RUSSIAN MARITIME REGISTER OF SHIPPING

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RULES
FOR THE CLASSIFICATION AND CONSTRUCTION OF SUBSEA PIPELINES

ND No. 2-020301-002-E

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LIST OF CIRCULAR LETTERS AMENDING/SUPPLEMENTING NORMATIVE DOCUMENT

ND No. 2-020301-002-E

Rules for the Classification and Construction of Subsea Pipelines, 2009

(Normative document No. and title)

Item No.	Circular letter No., date of approval	List of amended and supplemented paras
1.	003-4-481ц dated 16.06.2010	1.4.5.2

The Rules for the Classification and Construction of Subsea Pipelines of Russian Maritime Register of Shipping have been approved in accordance with the established approval procedure and come into force since 1 October 2009.

The Rules cover all technical aspects of design and construction of offshore subsea pipelines.

In development of the Rules experience of other classification societies has been taken into consideration.

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CONTENTS

1 GENERAL

1.1 SCOPE OF APPLICATION

1.1.1 The present Rules for the Classification and Construction of Subsea Pipelines (hereinafter referred to as "the SP Rules") cover the pipelines designed, constructed and operated offshore, subsea crossings of sections of shore main pipelines to the isolation valve nearest to the shoreline conveying liquid, gaseous and two-phase hydrocarbons as well as other media capable of being transported through the pipelines.

In addition to the present Rules during performance of the technical supervision Russian Maritime Register of Shipping (hereinafter referred to as "the Register") also applies the Guidelines on Technical Supervision During Construction and Operation of Subsea Pipelines, the Guidelines on Technical Supervision of Industrial Safety of Hazardous Production Facilities and their Equipment as well as the standards and rules of the national technical supervisory bodies.

1.1.2 In each particular case the scope of technical supervision carried out by the Register shall be stipulated by a special agreement with the pipeline owner and/or operating organization and, if necessary, agreed upon with the national technical supervisory bodies.

1.1.3 The SP Rules do not cover the hoses. Hoses shall comply with the requirements of Section 6, Part VIII "Systems and Piping" of the Rules for the Classification and Construction of Sea-Going Ships. Additional requirements may be imposed on the hoses within the subsea pipelines depending on the application.

1.1.4 The requirements specified by the SP Rules cover the documentation on subsea pipelines, the scope of surveys, strength, materials and welding, on-bottom stability, corrosion protection, laying methods, depth of burial into the seabed soil in the freezing water, testing, operation and safety assessment of subsea pipelines.

1.1.5 The SP Rules are applicable to single pipelines, pipeline bundles and pipelines of "pipe-in-pipe" type.

1.1.6 The Rules may be applied to existing pipelines built without the Register technical supervision for the purpose of carrying out survey of technical condition and confirming the possibility of their further service.

1.1.7 The Register may allow to use materials, structures, arrangements and products, other than those required by the SP Rules provided that they are as effective as those specified by the SP Rules. In the above cases, data shall be submitted to the Register enabling to ascertain that the materials, structures, arrangements and products in question meet the requirements ensuring the safety of media transportation through the subsea pipelines.

1.1.8 In case referred to in 1.1.6, the Register may require special tests to be performed during construction, and may reduce the intervals between periodical surveys or extend the scope of these surveys during operation.

1.1.9 The Register may approve subsea pipelines built in compliance with other rules, regulations or standards alternatively or additionally to the SP Rules. In well-grounded cases the pipelines shall be brought to conformity with the requirements of the SP Rules within the time period agreed upon with the Register.

1.1.10 Design, construction and operation of subsea pipelines shall meet the requirements of supervisory bodies in respect of environmental protection.

1.2 DEFINITIONS AND EXPLANATIONS

1.2.1 Atmospheric zone means the part of the pipeline above the splash zone.

Burial depth means the difference between the level of the pipeline top and the natural level of the seabed soil.

Pressure surge means an incidental pressure caused by a disturbance of steady flow in the pipeline system not exceeding the design pressure more than 10 per cent.

Splash zone height means the vertical distance between splash zone upper limit and splash zone lower limit.

Flexible pipes for subsea pipelines mean polimer-metal pipes with end connecting fittings, which allow large deflections from straightness without a significant increase in bending stresses (generally, the design pressure for flexible pipes shall comprise at least 1,6 MPa).

Sea depth means the vertical distance measured from the seabed to the average water level plus the total height of astronomical and storm tides.

Over-pressure means the difference between two absolute pressures, namely: outside hydrostatic and internal pressures.

Free span of pipeline means the pipeline length not touching the seabed or supporting facilities.

Permissible stresses mean the total maximum stresses in the pipeline (longitudinal, hoop and tangential) permitted by standards.

P i p e l i n e b u r i a l means placing of a subsea pipeline below the natural level of the sea bed soil.

S p l a s h z o n e means the pipeline section that is periodically in the water due to wave and current effects and water level fluctuations.

T e s t p r e s s u r e means the rated pressure applied to the pipeline during testing before its commissioning.

L e a k t e s t means a hydraulic pressure testing that ascertains absence of the transported medium leakage.

S t r e n g t h t e s t means a hydraulic pressure testing that ascertains structural strength of the pipeline.

I c e f o r m a t i o n is an integral solid substance made of sea or freshwater ice (e.g. stamukha, ridge, iceberg etc.) floating on the surface of the water.

I c e f o r m a t i o n k e e l is a portion of an ice formation that extends below the water line.

M i n i m u m y i e l d s t r e s s means the minimum yield stress specified in the manufacturer's certificate or standard, under which the steel pipes or products are supplied. It is assumed in calculations that the residual elongation will not exceed 0,2 per cent at the minimum yield stress.

P i p e n o m i n a l d i a m e t e r means an outside pipe diameter specified in the standard, under which the pipes are supplied.

N o m i n a l p i p e w a l l t h i c k n e s s means the pipe wall thickness specified in the standard, under which the pipes are supplied.

P i p e l i n e n e g a t i v e b u o y a n c y means a force directed downwards and equal to the weight of the pipeline structure in the air minus the weight of the water displaced by the pipeline submerged volume.

S u b s e a p i p e l i n e means the part of the pipeline system, which is located below the water level, including the pipeline itself, corrosion protection system of the pipeline components and other technical devices providing transportation of media under given operational conditions.

P i p e l i n e c o n s t r u c t i o n means a set of operations related to manufacture, laying and burial, if any, of a subsea pipeline.

D e s i g n p r e s s u r e means the pressure assumed as a permanent maximum pressure casued by the transported medium acting on the pipeline during operation, for which the pipeline system is designed.

S t i n g e r means a device installed on the pipe-laying vessel or barge and intended to provide a non-hazardous curvature of the pipeline and to reduce its bending stresses during laying.

Riser (production riser) means part of the subsea pipeline system connecting linear sections of piping on the seabed or subsea production facilities with the offloading/processing equipment installed on the floating/ fixed offshore platforms or floating structures.

Transported media mean liquid, gaseous and two-phase hydrocarbons and other media capable of being conveyed through pipelines.

Pipe-burying machines mean machines intended for burial of the on-bottom pipelines into the soil or for the preliminary trench excavation.

Pipe-layer (pipe-laying vessel/barge) means the special-purpose vessel intended for laying of subsea pipelines.

Laying of a pipeline by seabed pull means the operation consisting of the preliminary full-length installation of the pipeline on the site or seabed pull with successive tie-ins, using different pulling devices and equipment.

Pipeline laying by reeling means pipeline laying from a pipe-laying vessel with preliminary reeling on the special reel.

Pipeline laying by directional drilling means the combination of directional drilling operations and laying of subsea pipeline.

Pipeline laying by J-method means pipeline laying by free immersion on the seabed, using a sloped or vertical frame at sea depths more than 300 m. It consists of two stages: at the first stage the pipeline is lowered from a pipe-laying vessel vertically (or almost vertically) with tie-ins until the pipeline comes in contact with the seabed; at the second stage the pipeline bending occurs and the pipeline is laid on the seabed while the pipe-laying vessel is moving.

Pipeline laying by S-method means pipeline laying by free immersion on the seabed, in the course of which the pipeline section between the point of contact with the seabed and the stinger takes form of the S-curve.

Weight (ballasting) coating means the coating applied on the pipeline to provide its negative buoyancy and protection against the mechanical damages.

Gouging/Exaration is a ploughing of seabed soil by keels of ice formations.

1.3 CLASSIFICATION

1.3.1 The class notation assigned by the Register to the subsea pipeline consists of the character of classification, additional distinguishing marks and descriptive notations defining its purpose and structure.

1.3.2 The character of classification assigned by the Register to the pipeline consists of the following distinguishing marks: **SP⊛**, **SP★**, or **SP**$\underline{\bigstar}$.

Depending on the supervisory body, under which supervision the pipeline has been constructed, the character of classification is established as follows:

.1 subsea pipelines constructed in accordance with the Register rules and under technical supervision of the Register, are assigned a class notation with the character of classification **SP✪**;

.2 subsea pipelines constructed in accordance with the rules and under supervision of a classification body or national supervisory body recognized by the Register are assigned a class notation with the character of classification **SP★**;

.3 subsea pipelines constructed without supervision of the classification body or national supervisory body recognized by the Register are assigned a class notation with the character of classification **SP★̲**.

1.3.3 One of additional distinguishing marks:

L1, L2, L3, G1, G2 and G3 assigned to steel subsea pipelines in accordance with Table 1.3.3;

FP for subsea pipelines made of flexible pipes

shall be added to the character of classification.

Table 1.3.3

Additional distinguishing marks of steel subsea pipeline

Degree of operational reliability (reliability level)	Type of transported medium	
	Liquids and two-phase flows – L	Gas – G
High operational reliability	**L1**	**G1**
Transportation of aggressive media	**L2**	**G2**
Seismically active regions and ice resistant risers	**L3**	**G3**

1.3.4 The following descriptive notations shall be added to the character of classification and distinguishing mark:

geographical area;

type of transported medium;

working pressure, in MPa;

maximum temperature of transported medium, in °C;

nominal pipe diameter, mm/number of runs, pcs.

For example, **SP✪ L1**, **Baltic Sea**, **Crude Oil**, **6 MPa**, **40 °C**, **325/2.**

1.3.5 The Register may assign a class to the subsea pipeline on completion of its construction and assign or renew a class of the pipeline in service.

1.3.6 Assignment of the Register class to the subsea pipeline means confirmation of the pipeline compliance with the applicable requirements of the SP Rules, and acceptance of the pipeline under technical supervision for the specified period of time with performance of all surveys required by the Register to confirm the appropriate class.

1.3.7 Confirmation of class means confirmation by the Register of compliance of the pipeline technical condition with the class assigned and extension of the Register technical supervision for the set period of time.

1.3.8 Class of pipeline is generally assigned or renewed by the Register for 5 years, however, in sound cases the Register may assign or renew a class for a lesser period.

1.3.9 In case the subsea pipeline is not submitted to a mandatory survey within the prescribed time period, or it has not been submitted to survey after repair, or structural alterations not agreed with the Register have been made thereon, or the pipeline has been repaired without the Register supervision, the Classification Certificate for Subsea Pipeline ceases its validity, which results in suspension of class.

1.3.10 Withdrawal of class means termination of the Register technical supervision, and reinstatement of class is subject to a special consideration by the Register.

1.3.11 The Register may withdraw the class or refuse to perform technical supervision in cases when the pipeline owner or an operating organization regularly break the SP Rules, as well as in cases when the Party, which has made a survey agreement with the Register, violates it.

1.3.12 Materials and products used shall be subject to necessary surveys and tests during manufacture in the order and to the extent specified by the Register.

1.4 SCOPE OF SURVEYS

1.4.1 General.

1.4.1.1 The scope of surveys and classification covers the following stages of activities:

review and approval of technical documentation;

survey of materials and products intended for construction and repair of pipelines;

supervision during construction and repair of subsea pipelines;

surveys of subsea pipelines in service;

assignment, confirmation, renewal and reinstatement of the class, making appropriate entries and issue of the Register documents.

1.4.1.2 Any alterations made on the part of builders and owners in respect of the pipeline materials and structures, to which the requirements of the SP Rules apply, shall be approved by the Register before they are put into service.

1.4.1.3 Controversial issues arising during surveys may be transferred by the pipeline owners directly to the Register Head Office (RHO).

1.4.2 Survey of materials and products.

1.4.2.1 Materials and products shall be manufactured in accordance with the technical documentation approved by the Register.

During surveys the Register may check compliance with structural, technological, manufacturing standards and processes, which are not regulated by the Rules, but which influence the fulfillment of the requirements of the SP Rules.

1.4.2.2 Materials, products and manufacturing processes that are new or submitted to survey for the first time shall be approved by the Register. Specimens of materials and products or new manufacturing processes shall be tested according to the program and in the scope agreed with the Register subsequent to their technical documentation being approved by the Register.

1.4.2.3 The Register may perform supervision during manufacture of materials and products in the following forms:

survey by a surveyor;

survey of an enterprise by the Register;

survey in the form of review of the technical documentation by the Register;

survey on behalf of the Register.

The form of survey is selected by the Register when an agreement on technical supervision is made by the Register.

1.4.2.4 During survey materials and products shall be subjected to necessary tests according to the procedures and within the scope prescribed by the Register. The materials and products shall be provided with the documents specified by the Register and, where necessary, the brands confirming the fact of their survey, and marking enabling to determine their compliance with the above documents.

1.4.3 Technical supervision during construction, operation and repair of subsea pipelines.

1.4.3.1 Technical supervision during construction of subsea pipelines is performed by surveyors to the Register in compliance with the technical documentation approved by the Register. The scope of inspections, measurements and tests to be conducted during technical supervision is established by the Register with respect to the specific conditions for the pipeline.

1.4.3.2 During operation of the subsea pipeline their owners shall keep the terms of periodical and other surveys prescribed by the Register and properly prepare the pipeline for the surveys.

1.4.3.3 Pipeline owners shall notify the Register of emergencies and repairs of the pipeline and pipeline components covered by the requirements of the SP Rules that have taken place between the surveys.

1.4.3.4 Where the new components covered by the requirements of the Rules have been installed on the pipeline during its operation or repair, the provisions of 1.4.2, 1.4.3.1 to 1.4.3.3 shall be applied.

1.4.4 Types and frequency of surveys.

1.4.4.1 Subsea pipelines are subject to the following surveys:

initial, periodical (special, annual and intermediate) and occasional.

Initial surveys are divided into surveys carried out during construction of subsea pipelines under the Register technical supervision and surveys of subsea pipeline constructed under supervision of classification body recognized by the Register or national supervisory body.

Special survey for class renewal shall be generally carried out at 5-year intervals of the subsea pipeline operation in case of satisfactory results of annual surveys and one intermediate survey.

Annual surveys for confirmation of class shall be carried out every calendar year with a deviation from the prescribed date of the special survey within 3 months before and after this date.

Intermediate survey shall be carried out in the extended scope to confirm the class validity between special surveys.

Occasional survey shall be carried out after accidents, repairs and in other necessary cases.

1.4.4.2 Initial survey is performed with the aim to assign an appropriate class to the subsea pipeline that is initially submitted to the Register for classification. The subsea pipelines that were earlier classed by the Register, but which class was withdrawn by whatever reason, are also subject to initial survey. Initial survey includes thorough examination, inspections, tests and measurements, the scope of which is specified by the Register in each case depending on the environmental conditions of the pipeline operation, age of the pipeline, measures of its protection, technical condition of the pipeline, coatings, valves, etc.

1.4.4.3 Subject to initial survey are the subsea pipelines constructed not in accordance with the Register rules, without technical supervision of classification body recognized by the Register or national supervisory body. In such case, initial survey which scope is determined by the Register means thorough and overall survey, which shall be performed, where necessary, together with testing of the pipelines and components with the aim to confirm their compliance with the requirements of the SP Rules. Where documents issued for the subsea pipeline by classification body or national supervisory body recognized by the Register are available, initial survey is performed within the scope of special survey. In case the required technical documentation is not available to the full extent, the survey program may be extended for the components, the documentation on which is missing.

1.4.4.4 Surveys performed during construction of subsea pipelines shall be aimed at verifying compliance of the materials, components and manufacturing processes with the requirements of the technical design and detailed design documentation on the subsea pipeline. The scope of survey is subject to special consideration by the Register in each particular case.

The date of the pipeline survey upon completion of construction is the date of actual completion of the survey and issue of the Classification Certificate for Subsea Pipeline.

1.4.4.5 Special survey for class renewal is aimed to ascertain that the subsea pipeline is in a satisfactory technical condition and meets the requirements of the Rules. It is performed together with testing of the pipeline, valves, automated control system, alarm, protection and indication systems. Special surveys, which scope is determined by the Register, shall be carried out within the intervals established by the Register, as a rule, once every five years.

1.4.4.6 Mandatory annual survey means survey of the subsea pipeline, including valves, automated control system, alarm, protection and indication system, other components, in the scope adequate to confirm that the pipeline and its components keep complying with the requirements of the SP Rules, its class being thus confirmed.

The scope of annual surveys shall be established by the Register.

1.4.4.7 During special surveys of pipelines their testing under pressure shall be combined with testing in operation of their pump and compressor stations, shut-off and safety valves, remote by operated drives.

1.4.4.8 Intermediate survey of the subsea pipeline shall be carried out between special surveys instead of the second or third survey by agreement with the Register. The scope of survey shall be established by the Register.

1.4.4.9 Occasional surveys of the subsea pipelines or their individual components are performed upon submission for survey in all cases other than initial and periodical surveys. Occasional survey is carried out to assess permissible detected defects or damages after an accident, including those that result in pipeline leaks, spillage of fluids and emissions of gaseous transported media.

The scope and procedure of the surveys are defined by the Register on the basis of the survey purpose, age and technical condition of the subsea pipeline.

1.4.4.10 Occasional survey after an accident shall be aimed at identifying the type and nature of the damage, scope of work to be done for elimination of the accident consequences and at determining a possibility and conditions of retainment of class after elimination of the consequences.

1.4.5 Documents issued by the Register upon completion of the survey.

1.4.5.1 The Register documents are issued upon confirmation of the satisfactory assessment of the technical condition of the item of supervision made during surveys and tests.

1.4.5.2 The documents that confirm compliance with the requirements of the SP Rules are the Classification Certificate for Subsea Pipeline and the Certificate of Fitness of Subsea Pipeline for Operation.

1.4.5.3 Reports on survey (after construction, annual/intermediate/special survey) and other documents, if necessary, shall be issued by the Register during the supervision of subsea pipelines.

1.4.5.4 The Register may recognize fully or partially the documents of other classification societies, supervisory bodies and other organizations.

1.4.5.5 The Classification Certificate for Subsea Pipeline becomes invalid in the following cases: upon expiry;

if the subsea pipeline and its components are not submitted for periodical survey in terms with regard to the delays provided for periodical surveys in the Rules;

after repair conducted without the Register supervision or replacement of the components covered by the SP Rules;

in case the subsea pipeline is not in fit technical condition providing its safety;

when the pipeline is used for the purpose and under operational conditions different from those indicated in the class notation.

1.5 TECHNICAL DOCUMENTATION

1.5.1 Prior to commencement of the subsea pipeline construction, technical documentation, which allows ascertaining that the requirements of the Register rules for this subsea pipeline are met, shall be submitted to the Register for review.

The scope of the technical documentation is specified in 1.5.2 to 1.5.11. The additional instructions on the documentation composition given in the follow-up sections of the SP Rules shall be also taken into account.

1.5.2 General:

.1 specification;

.2 drawings (diagrams) of pipeline routing (rout location) with all data required for the design review;

.3 list of components and equipment with indication of the main technical characteristics, manufacturer and approval by the Register or another competent body.

1.5.3 Documentation on pipes.

1.5.3.1 The technical documentation to be submitted shall contain the dimensions, materials, technique and procedure for steel pipe welding. To be presented are:

.1 certificates for pipes and test reports thereof (specification for the pipe delivery or technical requirements for the pipe purchasing);

.2 drawings of pipe edge preparation for welding;

.3 drawings of pipeline sections;

.4 drawings of pipe strings (where pipes are laid in bundles);

.5 procedure for pipe welding;

.6 types and scope of tests;

.7 methods and scope of non-destructive testing;

.8 information on the medium to be transported;

.9 hydraulic calculation.

1.5.3.2 The following information and calculations shall be submitted together with the drawings:

.1 description of the laying method of the subsea pipeline on the seabed;

.2 necessary information for determination of external loads (forces and moments) due to wind, currents, water, ice and other parameters including accidental loads (caused by trawl nets, anchors, etc.) to be taken into account in the pipeline strength analysis;

.3 calculation of the pipe wall nominal thickness for appropriate load combinations;

.4 results of the required model tests, which may be used for confirmation or more accurate definition of substantiation and calculations;

.5 pipeline strength analyses during laying.

1.5.3.3 The flexible pipe documentation shall include the following particulars and calculations:

.1 certificates for pipes and test reports thereof (specification for the pipe delivery or technical requirements for the pipe purchasing);

.2 design of pipes and connecting elements (end fittings);

.3 properties of the metal and polymer materials used;

.4 methods of calculation of the parameters of all pipe layers including determination of design internal and external pressure, tensile and torsional strength;

.5 scope application of flexible pipes, including the parameters of transported medium;

.6 allowable types of exposure (static, dynamic, requirements for cycle and time resources) and permissible parameters of the environment;

.7 minimum bending radius during storage, laying and operation;

.8 strength calculations during laying, operation and tests including calculations of fatigue resistance;

.9 particulars on inspection and monitoring, including the design forecast of the pipe service life.

1.5.4 Documentation on weights used for the pipeline ballasting:

.1 calculation of subsea pipeline buoyancy (buoyant force);

.2 arrangement plan of ballast weight;

.3 design drawings of the ballast weight construction;

.4 ballasting calculations for the subsea pipeline when using concrete coated pipes.

1.5.5 Documentation on valves and their drives:

.1 arrangement plan for shut-off and safety valves;

.2 certificates and test reports on valves that confirm their suitability for the media to be transported and anticipated operational conditions;

.3 diagram of the pipeline valves remote control;

.4 design drawings of drives.

1.5.6 Documentation on shore crossings:

.1 description of the subsea pipeline on shore landfall;

.2 design drawings of shore crossing.

1.5.7 Documentation on laying the pipeline on the seabed:

.1 laying methods and process flow diagrams with indication of basic parameters;

.2 drawing of the trench or laying zone;

.3 description of trench backfilling.

.4 design of crossings with the preliminary laid pipelines and cables;

1.5.8 Documentation on the automated control and alarm systems:

.1 diagram of the alarm system that keeps under control transported medium characteristics, leakages, pump and compressor parameters; shut-off valve position;

.2 list of monitored parameters with the types of sensors and devices, and their characteristics specified;

.3 certificates for instrumentation, sound and light sources for instruments and other components of the alarm system.

1.5.9 Documentation on corrosion protection and isolation:

.1 certificates for corrosion-resistant coatings;

.2 substantiation for selection of the pipeline corrosion-resistant coating;

.3 scheme of the pipeline corrosion-resistant coating and isolation;

.4 instruction on preparation of the pipeline surface and application of corrosion protective coatings and isolation;

.5 cathodic protection scheme (anodes arrangement);

.6 determination of anodes weight.

1.5.10 Documentation on risk analysis.

Documentation shall be prepared in compliance with Section 10. It is allowed to perform risk analysis for the subsea pipeline through the stages of the offshore field development project design.

1.5.11 Where new components that are significantly different from the original ones and meet the requirements of the SP Rules are mounted on the subsea pipeline in operation, it is necessary to submit to the Register for review and approval the additional technical documentation on new products in the scope required for the subsea pipeline under construction.

1.5.12 In cases referred to in 1.3.5, the amount of technical documentation to be submitted to the Register is subject to special consideration by the Register in each particular case.

1.5.13 The standards for individual materials and products agreed upon with the Register may substitute an appropriate part of the technical documentation.

1.5.14 Prior to their implementation, amendments made in the technical documentation approved by the Register and dealt with the components and structures covered by the requirements of the Rules shall be submitted to the Register for approval.

1.5.15 The technical documentation submitted to the Register for review and approval shall be prepared in such a way or supplied with such additional information that it enables to make sure that the requirements of the SP Rules are met.

1.5.16 The calculations necessary for determination of the parameters and values regulated by the SP Rules shall be made in compliance with the provisions of the SP Rules or according to the procedures agreed upon with the Register. The procedures and methods used for calculations shall provide an adequate accuracy of the problem solution. Computer-aided calculations shall be made in accordance with the programs having a Type Approval Certificate. The Register may require performance of check calculations with the aid of any programme. The Register does not check the correctness of computing operations in calculations. The basic regulations regarding approval of the computer-aided calculation programmes and the calculation procedures are given in 12.2, Part II "Technical Documentation" of the Rules for Technical Supervision during Construction of Ships and Manufacture of Materials and Products for Ships.

1.5.17 Standards and normative documents on materials and products shall be agreed upon for the period of their validity. When revising the standards and normative documents, they shall be verified to take into account the requirements of the current rules and regulations of the Register.

1.5.18 The Register approval of the technical documentation is valid for a period of six years. Upon expiry of this term or in case where the interval between the date of approval and commencement of the pipeline construction exceeds three years, the documentation shall be verified and updated to take account of the amendments to the Register rules.

1.5.19 Approval of technical documentation is acknowledged by putting on it the appropriate stamps of the Register. The approval of the documentation by the Register does not relate to the elements and structures contained therein, to which the requirements of the SP Rules are not applicable.

2 DESIGN LOADS ACTING ON SUBSEA PIPELINES

2.1 Design loads acting on the subsea pipeline shall take into consideration operating conditions, test loads and loads during pipeline installation. Each type of loads defined in 2.2 to 2.8 shall be multiplied by significance factor γ. The values of factors are given in Table 2.1.

Table 2.1

Significance factors of load components γ

Type of load	γ
Weight of pipeline and auxiliary structures	1,1
Internal pressure:	
for gas pipelines	1,1
for oil- and petroleum product pipelines	1,15
External water pressure with regard to water level changes due to tides and waves	1,1
Pipeline icing in case the products with temperature below zero are transported	1,4
Seismic forces	1,1
Current force	1,1
Wave force	1,15
Wind force	1,1
Temperature action	1,0

2.2 Design pressure in the pipeline p_0, in MPa, is determined by the formula

$$p_0 = (p_i - p_{g\,\min}) + \Delta p \qquad (2.2\text{-}1)$$

where p_i – internal working pressure in the pipeline assumed in design, in MPa;

$p_{g\,\min}$ – minimal external hydrostatic pressure on the pipeline, MPa;

Δp – additional design pressure taking account of touch-up pressure of the transported medium in the pipeline and/or pressure of a hydraulic impact in the pipeline, in MPa. Additional design pressure is determined on the basis of the pipeline hydraulic calculation approved by the Register.

The value of $p_{g\,\min}$ is determined by the formula

$$p_{g\,\min} = \rho_w \cdot g \cdot (d_{\min} - h_w / 2) \cdot 10^{-6} \qquad (2.2\text{-}2)$$

where ρ_w – density of sea water (kg/m^3);
g – acceleration due to gravity (m/s^2);
$d_{\min}$ – the lowest still water level along the pipeline route, in m, taking into account tides and storm surges effects with 10^{-2} 1/year probability;
h_w – design wave height on the pipeline design section, in m, with 10^{-2} 1/year probability.

The value of the additional design pressure Δp, in MPa, taking account of the hydraulic impact shall be not less than the value determined by the formula

$$\Delta p = V_{int} \sqrt{\frac{\rho_{int} E \cdot t_c \cdot K}{E \cdot t_c + D_{int} \cdot K}} \cdot 10^{-3} \qquad (2.2\text{-}3)$$

where V_{int} – velocity of the medium to be transported in the pipeline, in m/s;
E – Young’s modulus of the pipe material, in MPa;
K – bulk modulus of the transported medium, in MPa;
ρ_{int} – density of the transported medium, in kg/m^3;
D_{int} – internal diameter of the pipe, in mm;
t_c – wall thickness of the pipe, in mm.

Where special structural measures are taken to reduce the hydraulic impact pressure (limitation of shut-off speed for valves, application of special devices for protection of the pipeline against transient processes, etc.) the value of Δp may be reduced in calculations by the value agreed with the Register.

2.3 The axial force due to temperature fluctuations shall take account of the loads arising from the changes in the pipeline length under the effect of temperature changes. Temperature difference in the pipe wall metal shall be assumed equal to the difference between the maximum and the minimum possible wall temperatures during operation and laying. The maximum and the minimum temperatures of pipeline walls during operation shall be determined depending on the environmental temperature, transported medium temperature, intensity of thermal interface between the pipeline and the environment.

2.4 The total linear load due to weight forces shall take into account weight of pipes, protective coatings, concrete coatings and ballast, different pipeline components (anodes, fittings, T-joints, etc.), transported medium, buoyancy forces. In case the pipeline is laid on the ground, and the temperature of the transported medium may be below zero, in buoyancy force calculations the possible icing of the pipelines shall be considered.

2.5 Linear loads: horizontal $F_{c,h}$, vertical $F_{c,v}$ and total F_c due to current, in N/m, are determined from the formulae:

$$F_{c,h} = c_x \frac{\rho_w V_c^2}{2} D_a; \tag{2.5-1}$$

$$F_{c,v} = c_z \frac{\rho_w V_c^2}{2} D_a; \tag{2.5-2}$$

$$F_c = \sqrt{F_{c,h}^2 + F_{c,v}^2} \tag{2.5-3}$$

where V_c – design current velocity projected on the normal to the pipeline axis at the depth of pipeline installation, in m/s, and determined for the given geographical region with 10^{-2} 1/year probability dased on the engineering survey;

ρ_w – sea water density, in kg/m^3;

c_x – pipeline resistance factor determined from Fig. 2.5-1;

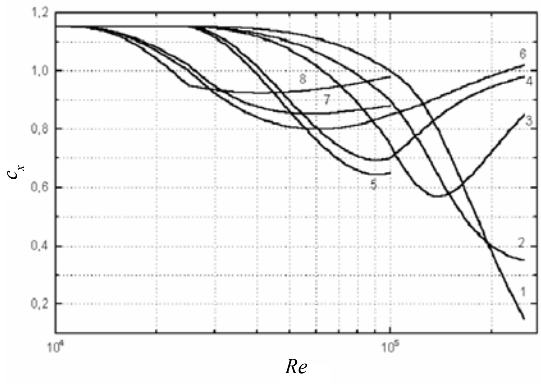


Fig. 2.5-1

Dependence of c_x factor from the Reynolds number and relative roughness of the pipeline surface:
1 – k = 0; 2 – k = 5,0 · 10^{-4}; 3 – k = 2,0 · 10^{-3}; 4 – k = 4,0 · 10^{-3}; 5 – k = 5,0 · 10^{-3};
6 – k = 7,0 · 10^{-3}; 7 – k = 9,0 · 10^{-3}; 8 – k = 2,0 · 10^{-2}

$c_x = c_x(k, Re)$

where $k = k_0/D_a$ – pipeline roughness factor;

k_0 – roughness ridge value, m;

Re – Reynolds number;

$Re = V_c D_a / \nu$;

D_a – pipeline outside diameter, in m;

$\nu = 1{,}2 \cdot 10^{-6}$, in m²/s, – seawater kinematic viscosity;

c_z – factor for on-bottom pipeline assumed equal to 0,8.

For pipelines laid at the distance d from the seabed, factors c_x and c_z are calculated according to the diagram in Fig. 2.5-2.

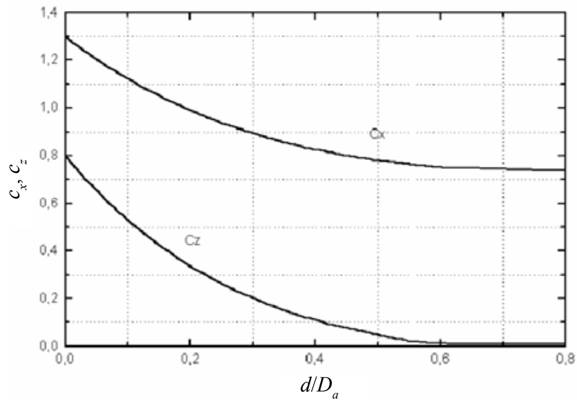


Fig. 2.5-2
Factors c_x and c_z depending on the relative distance of the pipeline from the seabed d/D_a

2.6 Horizontal linear wave load on the pipeline is calculated as superposition of resistance forces $F_{w,s}$, and inertia forces $F_{w,i}$, in N/m according to the formulas:

$$F_{w,s} = c_d \frac{\rho_w V_w^2}{2} D_a; \tag{2.6-1}$$

$$F_{w,i} = c_i \frac{\rho_w a_w}{2} D_a^2 \tag{2.6-2}$$

where ρ_w, D_a – refer to Formula (2.5-3).

The design wave particle velocity V_w, in m/s, and acceleration a_w, in m/s^2, projected onto the normal to the pipeline axis at the depth of pipeline installation shall be determined for the given geographical region with an exceedance probability of 10^{-2} 1/year for the most wave hazardous direction according to the results of a direct engineering survey lengthwise of the subsea pipeline route.

Appendix 5 provides the recommended data on the above components of the wave particle velocity and acceleration depending on the sea depth, height and period of waves with an exceedance probability of 10^{-2} 1/year, which shall be determined according to the results of the engineering survey. The Register reference data on wind and wave conditions may be used for specifying the wave height and period in those regions of sea water areas wherein these values were determined.

The total horizontal wave load $F_{w,g}$, in N/m, is determined by the formula

$$F_{w,g} = \sqrt{F_{w,s}^2 + F_{w,i}^2}. \tag{2.6-3}$$

Vertical linear wave load $F_{w,v}$, in N/m, is determined by the formula

$$F_{w,v} = c_v \frac{\rho_w V_w^2}{2} D_a. \tag{2.6-4}$$

Factors c_d, c_i, and c_v are determined depending on the Reynolds number and the pipeline relative surface roughness k according to the procedure agreed with the Register.

2.7 Linear wave loads F_{sl}, in N/m, due to wave impacts on the pipeline surface, in the splash zone are determined by the formula

$$F_{sl} = 1{,}6\,\rho_w V_{w,s}^2 D_a \tag{2.7}$$

where $V_{w,s}$ – design surface wave particle velocity projected on the normal to the pipeline axis, in m/s, and determined for the given geographical region with 10^{-2} 1/year probability for the most wave hazardous direction based on the engineering survey.

2.8 Linear wind loads $F_{w,d}$, in N/m, for the pipeline sections at a distance z, in m, above the still water level are determined by the formula

$$F_{w,d} = 0{,}23\, \rho_a V_{w,d}^2 z^{0,2} D_a \qquad (2.8)$$

where ρ_a – air density, in kg/m^3;

$V_{w,d}$ – design wind velocity, determined for the given geographical region whith 10^{-2} 1/year probability, in m/s.

2.9 Pipelines laid on the seabed in the freezing seas with an intensive gouging of the seabed due to the ice formations shall be protected against the ice effects by their burial into the seabed soil. Requirements for determination of subsea pipeline burial depth are given in 8.3 and in Table 2, Appendix 1.

2.10 Pipeline sections in water areas with seasonable seabed scouring caused by intensive river flow and specific environment (e.g. fast ice) shall be buried into the seabed soil for the depth h, in m, determined by the formula

$$h = h_{\max} + \Delta h \qquad (2.10)$$

where $h_{\max}$ – the maximum depth of the seasonal seabed scouring, in m, determined from the results of engineering survey of the pipeline section continuously during 5 years;

Δh = 1 m or according to Table 2 of Appendix 1.

2.11 Loads during the pipeline installation under keeping of standard environmental conditions (wind, waves, water and air temperatures) and installation procedure are determined depending on the laying method and environmental conditions.

2.12 The strength of a steel subsea pipeline shall be checked for the effect of seismic loads.

The vertical linear force, in N/m:

$$F_{s,z} = 0{,}06m \cdot \beta \cdot 2^{S-7} \cdot g. \qquad (2.12\text{-}1)$$

The horizontal linear force normal to the pipeline axis, in N/m:

$$F_{s,x} = (F_{s,z} + G) \cdot f \qquad (2.12\text{-}2)$$

where S – earthquake intensity with probability 1/1000 years;

m – linear pipeline mass with regard to ballast and the transported medium, in kg/m;

g – acceleration of gravity, g = 9,81 m/s^2;

β and f – dynamic factor and friction factor, respectively, depending on the type of a given soil, and being determined by Table 2.12.1;

G – linear weight of the pipeline in water, in N/m.

Table 2.12.1

Dynamic and friction factors

Type of soil	β	f
Rocky and semirocky	3,0	0,3
Clay, loam, grit stone	2,7	0,25
Fine-grained and medium sand, plastic clay	2,0	0,1

The total linear seismic force acting on the pipeline shall be determined by the formula

$$F_s = \sqrt{F_{s,x}^2 + F_{s,z}^2}. \tag{2.12-3}$$

The more precise assessment of seismic effects, which takes into account the orientation of the pipeline route relative to the probable direction of a seismic wave, parameters of the given type of soil, dynamic pipe-soil interactions, may be obtained by the procedure agreed with the Register.

3 STRENGTH OF SUBSEA PIPELINES

3.1 GENERAL

3.1.1 Strength analysis of the subsea pipelines shall be based on the classical or semi-empirical procedures that take into consideration the combination of external actual loads acting on the pipe and material resistance parameters of pipes having deviations from roundness.

3.2 DETERMINATION OF THE STEEL PIPELINE WALL THICKNESS

3.2.1 Selection of the steel subsea pipeline wall thickness, which is one of the most important design stages, shall be based on the necessity to ensure the pipeline strength (stability) and required safety level. The calculations shall be made for the most unfavorable combination of possible loads.

3.2.2 The wall thickness of the steel pipeline shall be determined based on the following conditions:

local strength of the pipeline characterized by the maximum values of hoop stresses;

adequate local buckling of the pipeline.

3.2.3 The wall thickness t_c of the steel pipeline, in mm, based on local strength calculations, is determined by the formula

$$t_c = \frac{p_0 D_a}{2\sigma\varphi} + c_1 + c_2 \qquad (3.2.3)$$

where p_0 – design pressure in the pipeline determined in accordance with 2.2;
D_a – outside diameter of the pipe, in mm;
σ – permissible stress of the pipe material (refer to 3.2.5), in MPa;
φ – strength factor determined depending on the pipe manufacturing method (refer to 3.2.4);
c_1 – corrosion allowance (refer to 7.2.4 and 7.2.5), in mm;
c_2 – manufacturing tolerance, in mm.

3.2.4 Strength factor φ is taken equal to one for seamless pipes and approved welded pipes recognized as being equivalent to seamless pipes.

For other welded pipes the value of strength factor is subject to special consideration by the Register in each particular case.

3.2.5 Permissible stress σ shall be taken equal to the least of the following values:

$$\sigma = \min\left(\frac{R_e}{n_e}, \frac{R_m}{n_m}\right) \qquad (3.2.5)$$

where R_e – minimum yield stress of the pipe metal, in MPa;
R_m – minimum tensile strength of the pipe metal, in MPa;
n_e – strength factor in terms of yield stress;
n_m – strength factor in terms of tensile strength.

The values of n_e и n_m based on the pipeline class are given in Table 3.2.5.

Table 3.2.5

Strength factors

Pipeline class	Submerged section		Shore and offshore sections in protected area	
	n_e	n_m	n_e	n_m
1	2	3	4	5
L1	1,18	1,75	1,23	1,78
L2	1,22	1,88	1,28	1,92
L3	1,25	2,0	1,33	2,05
G1	1,18	1,75	1,23	1,78

Table 3.2.5 – continued

1	2	3	4	5
G2	1,20	1,78	1,27	1,81
G3	1,22	1,81	1,33	1,92

N o t e s : 1. The protected area of the onshore pipeline sections is the main pipeline sections from the isolation valve nearest to the shoreline and further along the seabed at a distance not less than 500 m.

2. On agreement with the Register strength factors may be reduced in making special overall and local strength calculations, having regard to the particular local conditions in the area of pipeline laying and pipeline position on the seabed.

3.2.6 Maximum total stresses in the pipeline σ_{max}, in MPa, caused by the internal and external pressures, longitudinal forces (e.g due to thermal expansion and/or elastic bending of the pipeline sections), as well as the external loads referred to in Section 2 with regard to the pipeline out-of-roundness shall not exceed the permissible stresses:

$$\sigma_{max} = \sqrt{\sigma_x^2 + \sigma_{hp}^2 - \sigma_x \sigma_{hp} + 3\tau^2} \le k_\sigma R_e \qquad (3.2.6)$$

where σ_x – total longitudinal stresses, in MPa;
σ_{hp} – total hoop stresses, in MPa;
τ – tangential (shear) stresses, in MPa;
k_σ – strength factor in terms of total stresses.

Values of strength factors k_σ based on the pipeline class are given in Table 3.2.6.

T a b l e 3.2.6

Strength factors in terms of total stresses

Pipeline class	k_σ	
	For normal operational conditions	For short-term loads during construction and hydraulic tests
L1	0,8	0,95
L2	0,727	0,864
L3	0,696	0,826
G1	0,8	0,95
G2	0,762	0,905
G3	0,727	0,864

3.3 STEEL SUBSEA PIPELINE CALCULATIONS FOR BUCKLING (COLLAPSE) UNDER HYDROSTATIC PRESSURE

3.3.1 Along with the calculations for the internal pressure effect, the subsea pipeline shall be mandatory subjected to strength analysis in terms of external hydrostatic pressure p_e (refer to 3.3.3) capable to cause buckling of the pipeline wall at certain depths or cause hoop compressive stresses in excess of the permissible values (refer to 3.2.6).

3.3.2 Strength analysis of subsea pipelines for pure buckling shall be made for the most unfavorable conditions, i.e. for the minimum possible internal pressure and the maximum hydrostatic pressure:

generally the minimum internal pressure takes place during construction and drying of the pipeline internal surface after hydraulic tests (in such cases, it will be equal to the atmospheric pressure or even less where vacuum is used for drying);

the maximum water depth corresponds to the maximum hydrostatic pressure, taking into account the tides and storm surges, seasonal and many-year fluctuations of the sea level.

3.3.3 The value of the critical external pressure on the pipeline p_e, in MPa, that causes buckling of the cross-section but does not initiate plastic deformations in the pipe wall (so called elastic buckling) may be determined by the formula

$$p_e = \frac{1}{k_1} \cdot \frac{2E}{1 - \mu^2} \left(\frac{t_c}{D_a} \right)^3 \tag{3.3.3}$$

where E – Young's modulus of the pipe material, in MPa;
μ – Poisson's ratio;
D_a – outside diameter of the pipe, in mm;
t_c – wall thickness of the pipe, in mm;
k_1 – strength factor determined from Table 3.3.5.

3.3.4 Depending on elastic and plastic properties of the pipe material and with certain ratio between the pipe diameter and wall thickness, the level of hoop compressive stresses may reach the yield stress with an increase of the external load even before buckling occurs. The value of buckling pressure p_y, in MPa, is determined by the following formula:

$$p_y = \frac{2R_e}{k_2} \cdot \frac{t_c}{D_{int}} \tag{3.3.4}$$

where D_{int} – internal diameter of the pipe, in mm;
R_e – refer to Formula (3.2.5);
t_c – wall thickness of the pipe, in mm;
k_2 – strength factor determined from Table 3.3.5.

3.3.5 Bearing capacity of the subsea pipeline cross-section for pure buckling under the external pressure shall be checked by the formula

$$p_c \leq k_c \cdot p_{g\,\max} \qquad (3.3.5\text{-}1)$$

where p_c – bearing capacity of the pipeline cross-section, in MPa, determined by formula (3.3.5-2);
k_c – strength factor determined from Table 3.3.5;
$p_{g\ \max}$ – maximum external pressure acting on the pipeline, in MPa, determined by Formula (3.3.5-3);

$$p_c = \frac{p_y \cdot p_e}{\sqrt{p_y^2 + p_e^2}} \qquad (3.3.5\text{-}2)$$

where p_e and p_y – critical loads in terms of elastic and plastic buckling determined by Formulae (3.3.3) and (3.3.4) respectively;

$$p_{g\,\max} = \rho_w \cdot g \cdot (d_{\max} + h_w / 2) \cdot 10^{-6} \qquad (3.3.5\text{-}3)$$

where ρ_w – sea water density, in kg/m^3;
g – gravity acceleration, in m/s^2;
$d_{\max}$ – the highest still water level along the pipeline route, in m, taking into account tides and storm surges with 10^{-2} 1/year probability;
h_w – design wave height on a certain pipeline section, in m, with 10^{-2} 1/ year probability.

Table 3.3.5

Strength factors for pipeline pure buckling

Pipeline class	k_1	k_2	k_c
L1	2,0	1,05	1,5
L2	2,3	1,1	1,65
L3	2,5	1,2	1,8
G1	1,8	1,05	1,4
G2	2,0	1,1	1,5
G3	2,2	1,2	1,65

Formula (3.3.5-2) is valid providing that

$$15 < D_a/t_c < 45$$

and that initial (manufacture) out-of-roundness of the pipes shall not exceed 0,5 per cent. Out-of-roundness is determined by the formula:

$$U = \frac{D_{a\,\max} - D_{a\,\min}}{D_a} \tag{3.3.5-4}$$

where $D_{a\,\max}$ and $D_{a\,\min}$ – maximum and minimum outside diameter of the pipe respectively, in mm.

3.4 STEEL SUBSEA PIPELINE LOCAL BUCKLING ANALYSIS

3.4.1 Local buckling means buckling of the pipe initial shape in the form of breaking or distortion under the external hydrostatic pressure, longitudinal forces and bending moment.

3.4.2 Analysis of the subsea pipeline for buckling during laying under the loads referred to in 3.4.1 shall be made according to the inequality

$$\left(\frac{p_{g\,\max}}{p_c}\right)^{n_1} + \left(\frac{M}{M_c}\right)^{n_2} + \left(\frac{T}{T_c}\right)^{n_3} \le 1/n_c \tag{3.4.2-1}$$

where p_c – critical external pressure, which causes local buckling of the pipe, in MPa, and determined by Formula (3.3.5-2);
M_c – critical bending moment, in kNm, determined by the formula

$$M_c = (D_{int} + t_c)^2\, t_c\, R_e \cdot 10^{-6}; \tag{3.4.2-2}$$

T_c – critical longitudinal force, in kN, determined by the formula

$$T_c = \pi\,(D_{int} + t_c)\, t_c\, R_e \cdot 10^{-3}; \tag{3.4.2-3}$$

$p_{g\,\max}$ – refer to Formula (3.3.5-3);
M – design bending moment determined with regard to lateral forces due to waves, wind, current and bending moments during pipeline laying by various methods, in kNm;
T – design longitudinal force determined with regard to longitudinal forces during pipeline laying by various methods, in kN;
p_c, M_c and T_c – bearing capacity of the pipeline with regard to certain types of acting loads (rated values of individual force factors, provided there are no other types of loads);
D_{int}, t_c and R_e – refer to Formula (3.3.4);
n_c – safety factor taken from Table 3.4.2 may be reduced upon agreement with the Register after performance of testing on the pipe specimens;

n_1, n_2 and n_3 – factors determined experimentally on the pipe specimens under the combined loads, using the procedure approved by the Register. Where inequality (3.4.2-1) is met at $n_1 = n_2 = n_3 = 1$, no more exact determination is further required.

Table 3.4.2

Safety factor for pipeline local buckling analysis

	Pipeline class					
	L1	**L2**	**L3**	**G1**	**G2**	**G3**
n_c	1,2	1,4	1,6	1,1	1,3	1,5

3.4.3 In the calculations of subsea pipelines for buckling (collapse), the value of yield stress in compression under the combined effect of bending and compression shall be taken equal to 0,8 of the minimum pipe material yield stress.

3.5 STEEL SUBSEA PIPELINE PROPAGATION BUCKLING ANALYSIS

3.5.1 Propagation buckling means propagation of the local buckling of the subsea pipeline cross-section along the pipeline route. Propagation buckling occurs when the external hydrostatic pressure at large depths exceeds the critical value p_p.

3.5.2 The critical value of hydrostatic pressure p_p, in MPa, at which propagation buckling may occur is determined by the formula

$$p_p = 24 R_e \left(\frac{t_c}{D_a}\right)^{2,4} \qquad (3.5.2\text{-}1)$$

where t_c – wall thickness of the pipe, in mm;
D_a – outside diameter of the pipe, in mm;
R_e – minimum yield stress of the pipe material, in MPa.

Propagation buckling may be avoided provided that the following inequality is met:

$$p_{g\,\max} < 1{,}2\, p_p \qquad (3.5.2\text{-}2)$$

where $p_{g\,\max}$ is determined by Formula (3.3.5-3).

Where inequality (3.5.2-2) is not met, structural measures shall be taken to prevent propagation buckling of subsea pipeline or its section.

3.5.3 In order to prevent propagation buckling (for subsea pipeline protection) the following measures shall be taken:

increase in wall thickness of the pipeline along with increase of the sea depth;

installation of buckle arresters.

3.6 STEEL SUBSEA PIPELINE FATIGUE ANALYSIS

3.6.1 Pipeline strength shall be checked in terms of fatigue criterion on the basis of the linear accumulated damage hypothesis (Miner's Rule):

$$\sum_{i=1}^{m} \frac{n_i(\Delta\sigma_i)}{N_i(\Delta\sigma_i)} \leq 1/n_y \qquad (3.6.1)$$

where m – number of stress blocks;

$n_i(\Delta\sigma_i)$ – number of stress cycles in each stress block;

$N_i(\Delta\sigma_i)$ – appropnate points on the pipe material fatigue curve in each stress block;

$\Delta\sigma_i$ – change in stresses during a stress cycle determined as an algebraic difference of the highest and the lowest stresses during a cycle;

n_y – safety factor taken in accordance with Table 3.6.1.

Table 3.6.1

Safety factor for pipeline fatigue analysis

	Pipeline class					
	L1	**L2**	**L3**	**G1**	**G2**	**G3**
n_y	3,0	5,0	8,0	3,0	4,0	5,5

3.6.2 Fatigue strength assessment shall take into account asymmetric nature of cycle stress and two-dimensional stress of the pipe material.

3.6.3 The pipe material fatigue curve may be obtained by means of special tests or taken from an applicable international or national standard (such as GOST 25859-83) and agreed with the Register.

3.6.4 The following shall be taken into consideration in fatigue analysis:

operational cycles of pressure fluctuations between start and stop;

stress cycles during repeated pressure tests;

stress cycles caused by constraint of temperature deformation in operation;

vibration caused by vortex separation due to underwater currents;

periodical wave loads.

3.7 STRENGTH CALCULATION FOR STRUCTURAL COMPONENTS OF THE PIPELINE CONSISTING OF FLEXIBLE PIPES

3.7.1 Terms relating to unbonded flexible pipes.

Outer sheath means an extruded polymer layer used to protect the flexible pipe against the seawater, corrosion, abrasion and keep the axial armoring layer in design position.

Internal pressure sheath means an extruded polymer layer that ensures the pipe integrity (prevents leakage of transported medium in the environment).

Cage means an interlocked metal construction that can be used as the innermost layer to prevent collapse of the internal pressure sheath (or pipe) due to radial loads (internal and external hydrostatic pressure, local loads).

Unbonded flexible pipe means a pipe construction consisting of separate unbonded (unglued) polymer and metal layers that allows relative movement between the layers.

Axial armoring layer means a structural layer made of the helically wounded metal stripes with a lay angle 20° to 55° that provides the pipe resistance to the axial forces and internal pressure.

Intermediate sheath means an extruded polymer layer that prevents the contact abrasion of metal layers.

Radial armoring layer means a layer made of the interlocked metal stripes with a lay angle close to 90° that increases the resistance of the flexible pipe to the local loads.

Insulation layer means a material layer with low thermal conductivity that provides insulating properties of the flexible pipe.

3.7.2 Terms related to the bonded flexible pipes.

Armoring layer means helically wound cable integrated in elastomeric material with a lay angle, as a rule, 55º to the generating line that is used to sustain, totally or partially, tensile loads and internal pressure.

Additional layer means a material layer with low thermal conductivity that provides insulating properties of the flexible pipe.

Liner means a layer of elastomeric material in contact with the transported fluid/gas that provides the pipe integrity.

Coating means a layer of elastomeric material in contact with the external environment that is used to insulate the internal layers of the flexible pipe and prevent corrosion, abrasion and mechanical damage.

Bonded flexible pipe means a flexible pipe where metal reinforcement is integrated into solidified elastomeric material containing textile layers to obtain additional structural reinforcement or to separate elastomeric layers.

3.7.3 Requirements for the flexible pipe strength.

3.7.3.1 As a rule, design pressure of the flexible pipes shall generally comprise not less than 1,6 MPa. If the lesser values of the design pressure are used, the flexible pipes shall meet the requirements of Section 6, Part VIII "Systems and Piping" of the Rules for the Classification and Construction of Sea-Going Ships.

3.7.3.2 Calculations of the flexible pipe strength under operational, laying and testing loads shall be approved by the Register and executed by the procedure agreed with the Register. Calculation procedure shall be based on the national and international standards recognized by the Register as acceptable for use, e.g. ISO 13628-2 for unbonded flexible pipes and ISO 13628-10 for bonded flexible pipes.

3.7.3.3 The criterion of a limiting state for the polymer layers is an ultimate strains determined with due regard to creeping and potential strain ageing in operation.

3.7.3.4 Operational, laying and testing loads shall not result in the polymer layer strain, which exceeds:

.1 for unbonded flexible pipes in bending – 7 per cent, as well as 30 per cent wall thickness reduction due to creeping;

.2 for bonded flexible pipes – not more than 50 per cent of the ultimate strain of the aged material.

3.7.3.5 The strength criterion for the metallic layers of flexible pipes shall meet the condition:

$$\sigma_i \leq k_i \cdot \min (R_e, 0{,}9R_m) \qquad (3.7.3.5)$$

where σ_i – the maximum design stress in layer, in MPa;
R_e – the minimum yield stress of the layer metal, in MPa;
R_m – tensile strength of the layer metal, in MPa;
k_i – safety factor according to Table 3.7.3.5.

Table 3.7.3.5

Safety factors for calculating the flexible pipe strength

	Type of loading acting on flexible pipes in:		
	operation	laying	hydraulic testing
Armoring layers of bonded flexible pipes	0,55	0,85	0,91
Layers of unbonded flexible pipes:			
axial armoring layer	0,67	0,85	0,91
cage and radial armoring layer	0,55	0,85	0,91

3.7.3.6 The permissible bending radius of flexible pipes for storage/operation/laying shall be determined by the manufacturer considering the criteria in 3.7.3.3

to 3.7.3.5 and be specified in technical documentation for pipes subject to Register approval (refer to 1.5.3.3). For practical use in operation it is recommended to increase the maximum bending radius, as compared with the minimum one in storage (reeling the pipeline on the reel):

under static conditions of the flexible pipeline operation – by 10 %;

under dynamic conditions – by 50 %.

3.7.3.7 The flexible pipe cage shall be designed for buckling, at that the safety factor with regard to the critical stress value k_{ib} shall be equal to

$$k_{ib} = 0{,}67 \text{ if } (d_{\max} + h_w/2) \le 300 \text{ m};$$

$$k_{ib} = \left[\frac{(d_{\max} + h_w/2) - 300}{600}\right] \cdot 0{,}18 + 0{,}67 \text{ if } 300 < (d_{\max} + h_w/2) < 900 \text{ m}; \qquad (3.7.3.7)$$

$$k_{ib} = 0{,}85 \text{ if } (d_{\max} + h_w/2) > 900 \text{ m}$$

where $d_{\max}$ and h_w – values determined by Formula (3.3.5-3).

3.7.3.8 The end fitting design shall ensure its combined action with the sheath of a flexible pipe. The limiting state of the zone of joining the fitting and the pipe sheath shall be determined for all possible load combinations in accordance with the relation:

$$(\sigma_t, \sigma_e) \le k_f \cdot R_e \qquad (3.7.3.8)$$

where σ_t – tensile tangential stress, in MPa;
σ_e – equivalent (Mises) stress, in MPa;
R_e – the minimum yield stress of the material, in MPa;
k_f – safety factor equal to:
0,55 for operational conditions;
0,67 in laying;
0,91 for hydraulic testing.

3.7.3.9 The values of design parameters of pipe resistance (to external and internal pressure, tensile, torsion), as well as the bending radius of the flexible pipe are subject to confirmation upon the results of type tests (refer to 4.2.4).

3.7.3.10 For flexible pipes, durability shall be calculated taking into account effects of creeping and strain ageing of polymer layers, corrosion and erosion for metal layers (refer to 1.5.3.3.9). Design durability shall exceed the planned service life of the pipe not less than 10 times.

4 MATERIALS

4.1 GENERAL

4.1.1 The requirements of this Section cover the materials and products of carbon, carbon-manganese, low-alloy steel, and flexible pipes intended for subsea pipelines, which are subject to the Register technical supervision.

4.1.2 The requirements to the subsea pipeline steels shall take into account the features for both liquid pipelines (including oil, chemical and water pipelines) and gas pipelines in compliance with the subsea pipeline classification – refer to 1.3.

4.1.3 According to subsea pipeline classification (refer to 1.3) the requirements to the subsea pipeline steels shall take into account various pipeline reliability levels:

1 – steel used for high reliability pipelines;

2 – steel used for high reliability pipelines conveying aggressive media;

3 – steel used for pipelines operated in seismically active regions and for ice resistant risers.

4.1.4 The steels differing in chemical composition, mechanical properties, supply condition or manufacturing procedure from those indicated in the present Section are subject to special consideration by the Register. In this case the data confirming the possibility of these materials application in accordance with their purpose shall be submitted. It is allowed, upon agreement with the Register, to use materials that meet the requirements of national and/ or international standards.

4.1.5 For the flexible subsea pipelines, which meet the requirements of the SP Rules, an additional distinguishing mark is added to the character of classification, in accordance with 1.3.3. The requirements for the flexible pipes are specified by the Register, depending on the pipeline purpose (refer to 4.2.4).

4.1.6 The materials subject to the Register technical supervision shall be produced by the manufacturers recognized by the Register and having the relevant document – the Recognition Certificate for Manufacturer/Type Approval Certificate (refer to 4.2.1).

4.1.7 The general provisions regulating the scope and procedure of technical supervision of materials are set forth in Section 5, Part I "General Regulations for Technical Supervision" of the Rules for Technical Supervision During Construction of Ships and Manufacture of Materials and Products for Ships and in 1.3, Part XIII "Materials" of the Rules for the Classification and Construction of Sea-Going Ships.

4.2 SURVEY AND TECHNICAL SUPERVISION

4.2.1 Survey and recognition of manufacturers of materials and products.

4.2.1.1 The firms manufacturing materials and products in compliance with the requirements of the present Section shall be, as a rule, recognized by the Register prior to commencement of manufacture of products. For this purpose survey of the firm shall be carried out, which comprises the following:

review and approval of technical documentation specifying the properties of materials and conditions of production;

familiarization with the production and the quality control system of the firms, conducting of check testing.

In course of taking the above actions, a compliance of the manufacture parameters and the products with the requirements of the submitted documentation and the Rules of the Register shall be confirmed, as well as the appropriate level of quality stability;

issue of the survey results – the Recognition Certificate for Manufacturer (where the results are satisfactory);

drawing-up of the survey results in compliance with the requirements of the Nomenclature of items of the Register technical supervision of subsea pipelines (refer to 1.6 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines) – the Recognition Certificate for Manufacturer or Type Approval Certificate (if the results are satisfactory).

4.2.1.2 All the procedures necessary for obtaining the Recognition Certificate for Manufacturer and Type Approval Certificate and the documents, confirming the recognition of the firms and its products by the Register shall be executed in accordance with the requirements of Section 2, Part III “Technical Supervision During Manufacture of Materials” of the Rules for Technical Supervision During Construction of Ships and Manufacture of Materials and Products for Ships, 1.7 and 2.6.1 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines based on the application of the firms.

4.2.1.3 Where rolled products and/ or tubular billets are supplied to the tube-rolling mill by other firms, the manufacturers of the above mentioned semi-finished products shall be recognized by the Register (have the Recognition Certificate for Manufacturer).

4.2.2 Surveys during manufacture (carrying out of technical supervision).

4.2.2.1 All materials and products manufactured in compliance with the requirements of the present Section shall be subject to survey during manufacture including surveys and tests in the scope meeting the requirements of the present Section and/or technical documentation approved by the Register.

4.2.2.2 Technical supervision during manufacture includes:

tests and inspection;

issue of the Register documents.

4.2.3 Testing of steel rolled products and pipes.

4.2.3.1 Check testing in course of the firm recognition.

4.2.3.1.1 Testing shall be conducted in compliance with the program submitted by the firm and approved by the Register. The program is compiled on the basis of the respective requirements of the present Section (refer to 4.2.3.5), national and/or international standards and other technical documentation approved by the Register.

4.2.3.1.2 Testing shall be conducted in the presence of the Register representative following the procedures agreed with the Register.

The site and time of the tests shall be specified by the manufacturer in advance. Sampling, test procedures, specimen cutout diagrams shall be effected in compliance with the applicable requirements of the SP Rules (refer to 4.3) and the relevant standards.

4.2.3.2 Testing in the course of manufacture**.**

4.2.3.2.1 Testing shall be conducted in compliance with the requirements of the SP Rules and the documentation on the products to be delivered approved by the Register. The tests shall be also carried out in the presence of the Register representative.

4.2.3.3 General.

4.2.3.3.1 Testing methods and procedures shall be chosen in compliance with the requirements of 4.3. Special testing procedures as well as the relevant evaluation criteria, if no instructions are contained in the SP Rules, shall be agreed with the Register.

4.2.3.3.2 Where the tests cannot be carried out at the facilities of manufacturer of the products to be approved, the required tests shall be conducted in a laboratory recognized by the Register.

4.2.3.3.3 Unless otherwise specified, the Register representative shall brand the samples and specimens.

4.2.3.3.4 Test results shall be noted in the report, including:

identification number;

date of test performance;

name of the testing laboratory;

name of the customer;

test type;

type and size of metal products to be tested, trade mark of material and heat treatment;

number and name regulatory document on the test;

marking (number of cast, batch, plate, pipe, size of pipe/plate, etc.);

position and direction of cutting of specimens;

test results;

any deviations from the procedures;

type of a testing machine, metrological calibration.

The report signed by the authorized person of the testing laboratory shall be submitted to the Register for review.

4.2.3.4 Unsatisfactory test results.

4.2.3.4.1 Where the test results are unsatisfactory, unless otherwise specified in the relevant chapters of the present Section, re-testing shall be conducted with the following conditions being observed:

.1 during recognition of a firm (initial testing) in case of unsatisfactory test results, the Register may suspend its performance until the relevant explanations are received and stop testing, where the test results have been effected by the factors other than sampling, manufacture or specimen defects, malfunction of equipment, etc.;

.2 where the test results during manufacturing process are unsatisfactory with regard to at least one type of tests, additional testing shall be conducted on the double number of pipes from the submitted batch. In case of unsatisfactory results of one of the additional tests, the batch shall be rejected.

The pipes from the batch rejected may be submitted to tests item-by-item, and where the results are satisfactory, they may be accepted. However, the batch shall be also rejected, if the total number of the pipes rejected exceeds 25 per cent of the batch.

In this case, the Register may suspend the technical supervision of pipes manufactured by the same technological procedure as the batch rejected. The manufacturer shall submit the report on test results, and the Register is entitled to require performance of check tests in the scope of initial testing;

.3 in any case, where the test results are unsatisfactory with regard to any type of tests, the cause shall be identified and corrective actions specified.

Where the test results have been affected by such factors as sampling, manufacture or specimen defects, malfunction of equipment, etc., it is allowed to repair/replace the equipment and/or specimens by other specimens from the same pipe and to carry out re-testing.

During manufacture at the firm recognized by the Register, the pipes rejected with respect to mechanical properties, grain size and corrosion test results but subjected to reheat treatment may be submitted as the new batch upon agreement with the Register;

.4 where necessary, the requirements related to unsatisfactory test results specified in 1.3.2.3, Part XIII "Materials" of the Rules for the Classification and Construction of Sea-Going Ships may be additionally applied;

.5 if confusion of specimens or test results has been detected or the test results do not make it possible to assess the material properties with the required degree of accuracy, the Register may require the tests to be repeated in the presence of its representative;

.6 the product or a semi-finished product manufactured, the properties of which do not fully agree with the requirements of this Section, the deviations being not essential for the operation of the structure or product, may be used in accordance with the purpose only subject to special consideration of the deviations by the Register and in case a relevant application from the manufacturer and agreement of the customer are available.

4.2.3.5 Scope of testing.

4.2.3.5.1 The scope of testing during recognition a firm (initial survey).

4.2.3.5.1.1 The scope of testing of pipes or rolled sheets – pipe billets (skelp) shall be determined considering the requirements of Table 4.2.3.5.1.1. In order to confirm the stable quality of products, tests with respect to each production process and pipe size shall be carried out on two batches consisting of 10 pipes.

Where the same production process (including heat treatment modes) is used in the manufacture of pipes of different sizes, tests on pipes of the maximum (first batch) and minimum (second batch) sizes (diameter, wall thickness) are allowed to be performed.

A batch shall consist of pipes and tubes of the same cast, the same grade, the same heat treatment conditions, the same diameter and wall thickness.

The test results shall meet the requirements of 4.5, documentation agreed with the Register and/ or recognized national and international standards for steel to be delivered.

4.2.3.5.1.2 The scope of testing of rolled sheets (skelp) shall be determined considering the requirements of Table 4.2.3.5.1.1 on 10 plates selected one after another in the rolling process.

The properties of the rolled product shall meet the requirements of the present Rules, specifications of steel supply and recognized national and international standards.

4.2.3.5.1.3 Generally, samples for testing seamless pipes shall be cut out from the pipes directly, and those for testing welded pipes – from the rolled product and the pipe (refer to 4.3).

4.2.3.5.1.4 The welding procedure and welding consumables used for the pipe manufacture shall be approved by the Register during manufacturer survey.

4.2.3.5.1.5 Strain ageing sensitivity tests shall be carried out on samples taken from the pipes after maximum permissible rolling-off.

4.2.3.5.1.6 Types and number of tests may be elaborated by the Register based on preliminary information submitted by the manufacturer (refer to 4.2.3.1). In particular, the indicated number of casts, semi-finished products and steel grades to be submitted for testing may be reduced or, at the Register discretion, the tests can be omitted altogether. The decisions shall be taken based on the following provisions:

.1 the firm has already been recognized by other classification society, and the documentation is available confirming the completion of the required tests and their results;

.2 for pipes and steel grades, the recognition of production of which by the Register was applied for, some statistical data are available confirming the stability of chemical analysis results and properties;

.3 the production process, condition of supply, control and test procedure as compared to those mentioned in 4.2.3.5.1.6.1 were not changed;

.4 recognition of pipe manufacture from steel of one strength level may be extended to pipes made from steel of a lower strength level, provided that the latter is manufactured using the same manufacturing process, including deoxidation and grain-refinement, as well as the casting method and condition of supply, diameter and wall thickness of the pipe, control and test procedures;

.5 changes in condition of the manufacturer recognition by the Register as compared to the application;

.6 recognition of manufacture of pipe steel, semi-finished products, such as slabs, blooms and billets by the Register or other classification society is available.

The number of pipes, casts and semi-finished products of various thicknesses to be submitted for testing may be increased in case of introduction of new manufacturing process or pipes differing in dimensions, steel grades and rolled product types from those specified in the original application.

4.2.3.5.1.7 Where special material properties required to be confirmed based on the application conditions, the results shall be additionally submitted or relevant tests carried out confirming these properties, e.g. tension at high temperature, fatigue tests, etc.

Table 4.2.3.5.1.1

Scope of tests for recognition of manufacturer

Type of tests	Position of samples, direction of cutting of specimens	Minimum number of plates taken from cast/batch (pipes taken from cast/batch)	Minimum number of samples taken from plate (pipe)	Minimum number of specimens taken from plate (pipe)	Notes	Total number of specimens taken from cast (batch of pipes)
1	2	3	4	5	6	7
Chemical analysis (4.3.4)	Pipe body, rolled product, from one end	2 X10 / 2	1	1	Complete analysis, including micro alloying + ladle sample	2
Tensile tests (4.3.2)	Pipe body, rolled product, from both ends, transverse	2 X10 / 20	2	2	Values of R_e, R_m, A_5, RA are determined	40
Tensile test with stress relieved (for steel subjected to thermo-mechanical controlled processing (TMCP)) (4.3.2)	Rolled product only, from both ends, transverse	2 X10 /20	2	2		40
Compression test after tension (4.3.2)	Rolled product only, from both ends, transverse	2 X10 /20	2	2	Values of R_e, R_m are determined under compression	40
Compression test (4.3.2)	Pipe only, from both ends, transverse	2 X10 /20	2	2	Values of R_e, R_m are determined under compression	40
Bend test (4.3.9.4; 3 of Appendix 4)	Pipe only, from both ends, transverse	2 X10 /2	2	2	Bending angle is determined	4

Table 4.2.3.5.1.1 – continued

1	2	3	4	5	6	7
Impact test to establish transition curve (4.3.3.3)	Rolled product, from both ends, transverse Form one end, longitudinal	2 X10 /2	2 1	24T 12L	Test temperature, in °C, + 20, - 10, - 20, - 40, - 60	108
Impact test on strain aged specimens (4.3.3.6)	Rolled product only, from one end (top), longitudinal, 1/4 of the width	2 X10 /2	1	12L	Test temperature, in °C, + 20, - 10, - 20, - 40, - 60	36
Sulphur segregation (4.3.4)	Pipe , rolled product, from one end	2 X10 /2	1	1		3
Metallography (4.3.5)	From one end	2 X10 /2	1	1		3
Corrosion test (4.3.9.5)	From one end	2 X10 /2	1	3		3
Drop-weight tear test (DWTT) (4.3.9.2; 1 of Appendix 4)	From one end, transverse	2 X10 /2	1	10	Determination of critical temperature	30
Test to determine the value of ductile-brittle transition temperature T_{kb} (4.3.9.6)	Rolled product only, from one end, transverse	2 X10 /2	1	10	Determination of critical temperature	30
Test to determine nill-ductility temperature (NDT) (4.3.9.7)	From one end, transverse to the plate, but longitudinally to the pipe	2 X10 /2	1	8	Determination of critical temperature	24

1	2	3	4	5	6	7
CTOD (crack tip opening displacement) test of the base material (4.3.9.3; 2 of Appendix IV) and weld joint (5.1.2)	From one end, transverse	2 X10 /2	1	12	Test temperature, in °C, - 10, - 20, - 40, - 60	36
Ultrasonic testing (4.3.8.3)	Throughout the length	2 X10 /20				
Hydraulic pressure test (4.3.7)	The whole pipe	2 X10 /20				
Weldability test (4.3.6)		2 X10 /2				

4.2.3.5.2 Scope of testing during manufacture.

4.2.3.5.2.1 The scope of testing during manufacture shall be determined based on the national and international standards recognized by the Register, the documentation on delivery of product approved by the Register and the requirements of the present Section (refer to Table 4.2.3.5.2.1). Table 4.2.3.5.2.1 contains the minimum required scope of testing.

4.2.3.5.2.2 Generally, one pipe out of a batch of 50 pipes shall be taken for tests.

A batch shall consist of pipes of the same cast, grade, heat treatment mode, diameter and wall thickness. For steel grades with the base temperature equal to –20 °C and lower (refer to 4.5.1.2) impact tests shall be carried out on each pipe.

The rolled product thickness (pipe wall) in a batch shall not differ by more than 10 mm. The pipe diameter in the batch shall not differ by more than 20 mm. As a rule, test samples are taken from the thickest rolled products (pipes) of the batch.

Table 4.2.3.5.2.1

Scope of tests during manufacture

Type of test	Position of samples, direction of cutting of specimens	Minimum number of plates taken from cast/batch (pipes taken from cast/batch)	Minimum number of samples taken from plate (pipe)	Minimum number of specimens taken from plate (pipe)	Notes	Total number of specimens taken from cast (batch of pipes)
Chemical analysis (4.3.4)	Pipe body, rolled product, from one end	50/1	1	1	Complete analysis, including micro alloying + ladle sample	2
Tensile test (4.3.2)	Pipe body, rolled product, from both ends, transverse	50/1 (refer to 4.2.3.5.2.2)	2	2	Values of R_e, R_m, A_5, RA are determined	40
Impact test (4.3.3.4)	Pipe body, rolled product, from one end	50/1 (refer to 4.2.3.5.2.2)			Base temperature for steel grade	3
Corrosion test[1] (4.3.9.5)	From one end	50/1 (refer to 4.2.3.5.2.2)	1	3		3
Ultrasonic testing (4.3.8.3)	Throughout the length	50/50 (refer to 4.2.3.5.2.2)				
Hydraulic pressure test (4.3.7)	The whole pipe	50/50 (refer to 4.2.3.5.2.2)				
Drop-weight tear test (DWTT) (4.3.9.2; 1 of Appendix IV)	From one end, transverse	50/1	1	10	Determination of critical temperature	30

[1] Corrosion tests shall be conducted for pipelines of class **L2** and class **G2** only (refer to 1.1.3)

4.2.4 Tests of flexible pipes.

4.2.4.1 General.

4.2.4.1.1 Tests of flexible pipes are conducted:

to the extent of the tests during the Register surveys of the manufacturer for issuing the Type Approval Certificate in compliance with 2.6.1 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines;

to the extent of tests during the flexible pipe manufacture.

4.2.4.2 Type tests of flexible pipes.

4.2.4.2.1 Type tests of the flexible pipes are conducted according to the programme agreed with the Register. The programme shall be based on the requirements of the SP Rules, national and/or international standards or other Register-approved technical documentation.

4.2.4.2.2 Type tests are conducted to confirm the basic design parameters of the pipes of a certain dimension-type series, which range shall be determined taking into account the following:

internal/external diameter;

number and purpose of layers;

design of metallic and polymeric layers;

manufacturing processes, including lay angles;

transported medium;

internal/external temperature of the medium;

operational conditions and service life.

4.2.4.2.3 Each type of flexible pipes shall pass type tests, which are generally conducted to the fracture of specimens and shall include:

internal pressure burst tests;

hydrostatic buckling (collapse) tests;

tension tests;

bending stiffness tests (checking the minimum bending radius of flexible pipes);

torsion resistance tests.

4.2.4.2.4 One to three specimens for each type test are sampled from each type of flexible pipes. During manufacture of the given type of pipes of various diameters, it is allowed to conduct the tests on the pipes of the maximum diameter.

4.2.4.2.5 Content of type tests for flexible pipes may be changed depending on the pipe purpose by agreement with the Register. Types and number of tests may be also detailed by the Register on the basis of the preliminary information submitted by the Register: availability of certificates of another classification societies, recognition of manufacturer, etc.

4.2.4.2.6 Methods and results of the type tests shall meet the requirements of 2.6.5.2 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines.

4.2.4.3 Tests during manufacture of flexible pipes.

4.2.4.3.1 Tests during manufacture of flexible pipes are conducted in compliance with the requirements of the SP Rules according to the programme approved by the Register and developed on the basis of the national and/or international standards.

4.2.4.3.2 Each flexible pipe after manufacture shall be subjected to:

drift test;

hydrostatic internal pressure test;

adhesion test (for bonded flexible pipes only);

vacuum tests (for bonded flexible pipes only).

4.2.4.3.3 Depending on the flexible pipe purpose, the special tests are conducted by agreement with the Register, namely:

tests for electrical resistance measurement (for flexible pipes with an internal cage and when using the cathodic protection of end fittings);

tests of the capability to be operated at low temperatures, i.e. cold resistance (where the pipe sections above the water surface are provided);

tests for resistance to corrosive transported media;

fire tests (where the pipe sections above the water surface are provided).

Scope of specialized tests shall be agreed with the Register, proceeding from the operational conditions of the pipes.

4.2.4.3.4 Test procedures and results shall meet the requirements of 2.6.5.3 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines.

4.3 PROCEDURES OF TESTING STEEL ROLLED PRODUCTS AND PIPES

4.3.1 General.

4.3.1 Unless otherwise specified, the rolled products and pipes shall be tested in compliance with the requirements of the Rules, Section 2, Part XIII "Materials" of the Rules for the Classification and Construction of Sea-Going Ships and national and international standards and the documentation agreed with the Register.

4.3.1.1 The mechanical tests shall be conducted on pipes after heat treatment, rolling-off and final moulding and shall meet the requirements of national or international standards and/ or the documentation approved by the Register. Unless otherwise specified, for pipes with the diameter of 300 mm and more the mechanical test specimens shall be cut out parallel to the pipe axis.

4.3.1.2 Depending on steel grade, strength level and test type, samples shall be taken from the rolled products in compliance with the requirements of 3.2.5, 3.13.5 and 3.14.4, Part XIII "Materials" of the Rules for the Classification and

Construction of Sea-Going Ships, Section 2, Part XII "Materials" of the Rules for the Classification, Construction and Equipment of MODU/FOP considering provisions of the present Section.

4.3.1.3 The specimens for tensile and impact tests shall be manufactured in compliance with the requirements of 2.2, Part XIII "Materials" of the Rules for the Classification and Construction of Sea-Going Ships.

4.3.2 Base metal tensile and compression tests.

4.3.2.1 Tensile tests for plate shall be carried out on flat specimens with full thickness. Test samples shall be cut out so that the middle of the specimen working part was at a distance of one quarter of the width from the plate edge, the specimens shall be located transverse to rolling direction.

4.3.2.2 Tensile tests shall be carried out on pipes with thickness of up to 32 mm – using billets straightening; for large sizes the testing of cylindrical specimens is allowed using straightening of billet gripped sections only. Samples shall be cut out from the welded pipes so that the middle of the specimens working part was located at an angle of 90° to the pipe weld seam.

4.3.2.3 Base metal shall be tested on compression after extension on 2...5 per cent to determine the yield stress (Bauschinger effect).

4.3.2.4 Base pipe metal shall be subject to compression testing on double-cylindrical specimens; during manufacture straightening of gripped sections only is allowed.

4.3.2.5 Compressive yield stress reduction up to 20 per cent is allowed as compared to the minimum tensile yield stress, unless otherwise stated by the Register.

4.3.3 Impact test.

4.3.3.1 Test samples shall be cut out from the rolled product at one quarter of the plate width and from the welded pipe at an angle of 90° to the weld seam. Tests shall be carried out on V-notch specimens. Besides impact energy, percentage of tough (brittle) component shall be determined.

4.3.3.2 Impact test for steel of grade F (refer to 4.5.1.2) shall be conducted at the temperature of – 80 °C during the initial survey of manufacture.

4.3.3.3 During initial survey of pipe manufacture the impact tests shall be conducted at minimum three temperatures given in Table 4.2.3.5.1.1 to establish the transition curve. The Register may require these tests to be carried out on the rolled metal or on the pipe metal.

4.3.3.4 During pipe manufacture under the Register technical supervision the impact bending tests shall be carried out at the base temperature for this grade of steel (refer to 4.5.1.2).

4.3.3.5 Where steel grades not specified in the Rules are used, the tests may be conducted at design temperature. The test temperature shall be determined when approving the documentation on delivery of pipes. To ensure comparability of test results for different steel grades the temperature closest to the one divisible by 10 °C shall be taken as the test temperature.

In any case, the test temperature shall be stated in quality certificates issued by the manufacturer.

4.3.3.6 Strain ageing sensitivity tests shall be carried out during initial survey of manufacture on specimens cut out from the rolled product; samples shall be selected similar to impact tests samples. Metal strips from which specimens are cut out shall be subjected to tensile strain by the value corresponding to the maximum permissible one for the pipe bending, as a rule, up to 5 per cent.

Impact test specimens made of strips subjected to tensile strain are subject to even heating (artificial ageing) up to 250 °C, with 1 hour exposure at this temperature and subsequent cooling in the air.

Impact tests of these specimens shall be carried out at room temperature (within 18 to 25 °C) and at base temperature corresponding to the stated steel grade. Unless otherwise specified, tests are carried out at the initial survey of the manufacturer, at steel production process alterations and in doubtful or arguable cases related to the rolled products quality on the surveyor to the Register demand.

4.3.4 Chemical analysis, sulphur segregation.

Chemical analysis and sulphur segregation samples shall be taken from the center of the plate width, and in case of the welded pipe – from the side opposite to the weld seam.

4.3.5 Metallography.

4.3.5.1 Macro structural analysis is performed to determine strained structure, discontinuities, flakes etc. As a rule, for macro structural analysis transverse specimens are taken from the forward end of prototype semi-finished product or head of the breakdown. Unless otherwise specified, the macro structural analysis is required at the initial survey of the manufacturer, at production process alterations and, on the surveyor to the Register demand, in doubtful or arguable cases related to the quality of the rolled products to be delivered.

4.3.5.2 Micro structural analysis is performed to determine steel grain size.

The samples for metallographic analysis shall be taken from 1/4 ± 1/8 of the plate width and from a position located at an angle of 90º to the pipe weld seam. The photographs shall be representative of the surface structure, one quarter and one half of the plate thickness. The photomicrographs shall be taken at X100 and X400 magnification. The grain size and original grain shall be determined. Unless otherwise specified, the micro structural analysis is required at the initial survey of the manufacturer, at production process alterations and, on the surveyor to the Register demand, in doubtful or arguable cases related to the quality of the rolled products to be delivered.

4.3.6 Weldability.

The weldability tests at the initial survey of the manufacturer shall be carried out in compliance with the requirements stated in 5.1.2.2 and 5.2.4. The weldability tests, unless otherwise specified, shall cover all the acceptable welding technique, including pipe manufacture, pipe installation and repair welding. The necessary information concerning post-weld heat treatment shall be submitted.

4.3.7 Hydraulic pressure tests.

Each pipe shall be subjected to hydraulic pressure test.

The information concerning the test pressure calculation method shall be submitted.

The testing equipment shall be duly checked.

The reports shall contain the information concerning the pressure applied and the duration of tests for each pipe. The soaking times at test pressure shall be not less than 10 s.

The hydraulic pressure tests may be omitted on the pipes manufactured on U-shaped and O-shaped bending presses. In this case, the proposed alternative method of checking the pipe strength and continuity shall be subject to special agreement with the Register as soon as the data indicating the equivalence of methods are submitted.

4.3.8 Non-destructive testing.

4.3.8.1 The testing shall be carried out in compliance with the national and international standards recognized by the Register.

The testing procedures (technological methods, parameters, sensitivity, criteria) applied by the manufacturer shall be agreed with the customer.

4.3.8.2 Each pipe shall be tested. The examination shall be carried out after cold straightening, moulding, heat treatment and rolling-off. Testing procedure of the pipe ends and longitudinal welds shall be agreed separately considering the requirements of 5.3.2.

4.3.8.3 The ultrasonic testing of rolled products shall be carried out on each plate/pipe.

4.3.9 Special tests.

4.3.9.1 Table 4.3.9.1 contains the requirements to the nomenclature of base metal special tests based on the pipeline reliability level (refer to 4.1.3). Steel may be accepted for the pipeline manufacture only after performance of special tests given in Table 4.3.9.1. On the Register request, the scope of special tests at the initial survey of manufacture may be increased for any reliability level of pipelines.

The minimum required scope of special tests shall be determined upon agreement with the Register considering the stability of properties of metal to be delivered and the pipeline class.

Table 4.3.9.1

Nomenclature of special tests for subsea pipelines

	Level 1	Level 2	Level 3
Group L (liquid)	Not required	Corrosion tests, CTOD	DWTT, CTOD
Group G (gas)	DWTT	Corrosion tests, DWTT, CTOD	DWTT, CTOD

Notes: 1. Corrosion tests include sulphide stress cracking resistance tests and hydrogen-induced cracking/stepwise cracking resistance tests.
2. The DWTT requirements are mandatory only for steel of PCT36 grade and higher strength steels, for the pipes with a diameter of 300 mm and more.
3. The CTOD requirements are mandatory for all steel grades and thicknesses, for pipelines of levels 2 and 3 (**L2**, **L3**, **G2**, **G3** classes).

4.3.9.2 Determination of critical brittleness temperature using drop-weight tear testing (DWTT).

The sample (billet) used for manufacture of pipe specimens shall be cut out transverse to the longitudinal axis of the pipe, as regards the plate specimens – normal to the direction of rolling.

As a rule, tests shall be carried out on the pipe metal during the initial survey of the pipe manufacture. The tests may be also required during the initial survey of the rolled product manufacture.

The procedure and scope of testing, specimen cut out flow charts are given in para 1 of Appendix 4.

4.3.9.3 Determination of metal crack resistance properties (CTOD crack tip opening displacement)

The samples shall be taken from 1/4 ± 1/8 of the plate width and from a position located at an angle of 90° to the pipe weld seam.

At the Register discretion, the number of pipes, plates taken from the cast to be tested and their thickness, as well as the test temperatures may be changed proceeding from the intended use of steel or conditions of the order.

Definitions, general requirements to sampling and specimen manufacture, equipment are set forth in Section 2, Part XII "Materials" of the Rules for the Classification, Construction and Equipment of MODU/ FOP.

The CTOD testing procedure is specified in para 2 of Appendix 4.

As a rule, the tests are carried out on the pipe metal during the initial survey of the pipe manufacture. The tests may also be performed during the initial survey of the rolled product manufacture.

4.3.9.4 Determination of capability to withstand plastic strains, bending.

As a rule, the tests are carried out on the pipe metal during the initial survey of the pipe manufacture. The tests may be also required during the initial survey of the rolled product manufacture.

The testing procedure is specified in para 3 of Appendix 4.

4.3.9.5 Corrosion tests.

The tests shall be carried out where the relevant additional requirements of the customer's order documentation are available. The tests shall be performed during the initial survey of the pipe manufacture and in the course of delivery.

Unless otherwise specified, three specimens from each batch of pipes shall be tested.

4.3.9.5.1 Sulphide stress cracking resistance.

The test procedure is specified in para 4 of Appendix 4.

4.3.9.5.2 Determination of hydrogen-induced cracking, stepwise cracking resistance.

The test procedure is specified in para 5 of Appendix 4.

4.3.9.6 Tests for determination of ductile-brittle transition temperature T_{kb}.

The samples are taken from one quarter of the plate width. The Register may require to conduct tests of class **L3** and class **G3** pipes with the wall thickness equal to and exceeding 40 mm during the initial survey of the pipe manufacture.

The definitions, general requirements to test procedure, specimen manufacture and equipment are set forth in Section 2, Part XII "Materials" of the Rules for the Classification, Construction and Equipment of MODU/ FOP.

4.3.9.7 Tests for determination of nil-ductility temperature NDT.

The specimens shall be taken from $1/4 \pm 1/8$ of the plate width and from a position located at an angle of 90° from the pipe weld seam.

The Register may require to conduct tests of class **L3** and class **G3** pipes with the wall thickness equal to and exceeding 40 mm during the initial survey of the pipe manufacture.

The definitions, general requirements to test procedure, specimen manufacture and equipment are set forth in Section 2, Part XII "Materials" of the Rules for the Classification, Construction and Equipment of MODU/ FOP.

4.4 STEEL MATERIALS SELECTION

4.4.1 In general cases, steel materials shall be selected in compliance with the requirements of Sections 2 and 3, as well as considering the requirements of 4.1 and 4.5.

4.4.2 Properties of steel used for subsea pipelines shall comply with the pipeline specific application and operating conditions. Steel shall ensure structural and technological strength of pipelines conveying hydrocarbons at prescribed minimum operating temperature and operational loads. The allowance for degradation of the mechanical properties shall be taken into account during pipeline long-term service.

4.4.3 Steel grade shall be assigned for the pipeline (or its section) based on its operational conditions (the minimum value of temperatures specified in 4.5.1.2).

Unless otherwise specified, minimum temperature for the subsea pipelines shall be equal to - 10 °C, except for the sections located within the zone of complete freezing or the splash zone.

4.4.4 Clad steel for subsea shall be assigned considering the requirements of 3.17, Part XIII "Materials" of the Rules for the Classification and Construction of Sea-Going Ships.

4.5 STEEL FOR SUBSEA PIPELINES

4.5.1 General.

4.5.1.1 The requirements of the present Section cover the weldable steel plates and pipe steel intended for subsea pipelines subject to technical supervision during manufacture.

4.5.1.2 The following designations (identification marks) for grade of steel have been introduced:

.1 steel for the subsea pipelines shall have index PCT before identification mark for steel grade;

.2 then – identification mark for strength level.

The strength level shall be determined proceeding from the required minimum yield stress value:

for normal strength steel – 235 MPa

(strength level is omitted in the identification mark);

for higher strength steels – 315 MPa, 355 MPa, 390 MPa

(numerical designations 32, 36 and 40 are stated in the identification mark, respectively);

for high-strength steels – 420 MPa, 460 MPa, 500 MPa, 550 MPa, 620 MPa, 690 MPa;

(numerical designations 420, 460, 500, 550, 620, 690 are stated in the identification mark, respectively);

.3 after identification mark of strength level the alphabetical designation of temperature for steel grade may be added: B, D, E, F based on the impact test temperatures: 0 °C, – 20 °C, – 40 °C and – 60 °C, respectively.

For steels tested at a temperature – 10 °C the alphabetical designation is omitted;

.4 the marking may be ended with the alphabetical designation W – steel for welded pipes. Examples of identification marks:

PCTW: steel for welded pipes with a minimum yield stress of 235 MPa, temperature – 10 °C;

PCTE40: steel for seamless pipes with a minimum yield stress of 390 MPa, temperature – 40 °C;

PCT550W: steel for welded pipes with a minimum yield stress of 550 MPa, temperature – 10 °C.

Steel grade temperature, at the same time, determines the base temperature (T_B) of impact tests, CTOD and DWTT tests: 0 °C, – 10 °C, – 20 °C, – 40 °C and – 60 °C.

4.5.1.3 It is allowed, on special consideration by the Register, to deliver steel pipes in compliance with the requirements of national and international standards. In this case, special consideration means, except for comparison of reference data, the possibility to conduct additional tests, which may confirm compliance of steel with the above grades and its use for the intended purpose.

Table 4.5.1.3 based on comparison of strength characteristics contains the relevant analogs of domestic and foreign steel grades.

Table 4.5.1.3

Correspondence of steel grades to be delivered under national and international standards

Steel grade for subsea pipelines according to the Register rules	National pipe steel strength grade	Foreign pipe steel strength grade
1	2	3
PCT(W)	K38, K42	B
PCT32(W)	K50	X46
PCT36(W)	K52, K54	X52
PCT40(W)	K55	X60

Table 4.5.1.3 – continued

1	2	3
PCT420(W)	K56	X65
PCT460(W)	K60	X70
PCT500(W)	K60, K65	X70, X80
PCT550(W)	K65	X80
PCT620(W)	K70	X90
PCT690(W)	K80	X100

4.5.2 Chemical composition.

4.5.2.1 The chemical composition of steel and values of C_{eq} and P_{cm} shall meet the requirements of Table 4.5.2.1-1 – for the pipe plate and welded pipes; and Table 4.5.2.1-2 – for seamless pipes.

The chemical composition may comply with the requirements of national and international standards recognized by the Register. In any case, the chemical composition of steel shall be agreed with the Register during the initial recognition of manufacture of particular products.

4.5.2.2 The chemical composition of rolled products and pipes (welded and seamless) shall be controlled in the course of the manufacture.

4.5.2.3 Determination of C_{eq} is a mandatory requirement for the delivery of all steel grades up to the strength level equal to 500 MPa, including steels subjected to TMCP.

Determination of P_{cm} is a mandatory requirement for the delivery of all steel grades with the strength level equal to 460 MPa and more. In other cases, values of C_{eq} and P_{cm} are shown in certificates on the customer's request.

Carbon equivalent shall be determined by the formulae:

$$C_{eq} = C + Mn/6 + (Cr + Mo + V)/5 + (Ni + Cu)/15, \%; \qquad (4.5.2.3)$$

$$P_{cm} = C + (Mn + Cr + Cu)/20 + Mo/15 + Ni/60 + Si/30 + V/10 + 5B, \%.$$

Table 4.5.2.1-1

Chemical composition of rolled products and base metal used for the subsea pipeline welded pipes

	Content of elements, % by mass, not more									
Grade	PCTW	PCT32W	PCT36W	PCT40W	PCT420W	PCT460W	PCT500W	PCT550W	PCT620W	PCT690W
C	0,14	0,12	0,12	0,12	0,12	0,12	0,12	0,14	0,14	0,14
Mn	1,35	1,65	1,65	1,65	1,65	1,65	1,75	1,85	1,85	1,85
Si	0,40	0,40	0,45	0,45	0,45	0,45	0,45	0,45	0,50	0,55
P	0,020	0,020	0,020	0,020	0,020	0,020	0,020	0,020	0,020	0,020
S	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010
Cu	0,35	0,35	0,50	0,50	0,50	0,50	0,50	0,50	0,60	0,60
Ni	0,30	0,80	0,80	0,80	0,80	0,80	1,20	1,20	1,80	2,00
Mo	0,10	0,10	0,50	0,50	0,50	0,50	0,50	0,50	0,50	0,50
Cr	0,30	0,30	0,50	0,50	0,50	0,50	0,50	0,50	0,70	0,70
Al (total)	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06
Nb	–	0,04	0,05	0,06	0,06	0,06	0,06	0,06	0,06	0,06
V	–	0,04	0,05	0,07	0,08	0,10	0,10	0,10	0,10	0,10
Ti	–	0,04	0,04	0,05	0,06	0,06	0,06	0,06	0,06	0,06
N	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010
B	0,0005	0,0005	0,0005	0,0005	0,0005	0,0005	0,0005	0,0005	0,0005	0,0005
C_{eq}	0,36	0,34	0,37	0,38	0,38	0,39	0,41	0,44	–	–
P_{cm}	0,19	0,19	0,20	0,21	0,21	0,22	0,23	0,25	0,27	0,30

Notes: 1. For wall thickness δ exceeding 35 mm and for steel grades with strength higher than PCT550 the alteration of chemical composition is permitted subject to agreement with the Register.

2. Where scrap material has been used in steel production, the maximum content of the following elements shall be controlled: 0,03 % As, 0,01 % Sb, 0,02 % Sn, 0,01 % Pb, 0,01 % Bi and 0,006 % Ca.

3. For each reduction of 0,01 % carbon below the maximum specified value, an increase of 0,05 % manganese content above the maximum specified values is permitted with a maximum increase of 0,1 %.

4. Alloying of 0,5 – 1,0 % Cr is permitted subject to agreement with the Register.

5. For steel grades with strength higher than PCT550 alloying up to 2,2 % of Ni is permitted.

6. Al:N ≥ 2:1 (not applicable for titanium killed steel).

7. (Nb + V + Ti) shall not to exceed 0,12 %.

8. The Nb content may be increased to 0,10 % subject to agreement with the Register.

9. The B content may be increased to 0,003 % subject to agreement with the Register.

10. For class **L2** and class **G2** pipelines C ≤ 0,10 %, P ≤ 0,015 % and S ≤ 0,003 %.

Table 4.5.2.1-2

Chemical composition of seamless pipes of the subsea pipelines

Grade		Content of elements, % by mass, not more									
		PCT	PCT32	PCT36	PCT40	PCT420	PCT460	PCT500	PCT550	PCT620	PCT690
C		0,14	0,14	0,14	0,14	0,14	0,15	0,16	0,16	0,16	0,16
Mn		1,35	1,65	1,65	1,65	1,65	1,65	1,75	1,85	1,85	1,85
Si		0,40	0,40	0,45	0,45	0,45	0,45	0,45	0,45	0,50	0,55
P		0,020	0,020	0,020	0,020	0,020	0,020	0,020	0,020	0,020	0,020
S		0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010
Cu		0,35	0,35	0,50	0,50	0,50	0,50	0,50	0,50	0,60	0,60
Ni		0,30	0,80	0,80	0,80	0,80	0,80	1,20	1,20	1,80	2,00
Mo		0,10	0,10	0,50	0,50	0,50	0,50	0,50	0,50	0,50	0,50
Cr		0,30	0,30	0,50	0,50	0,50	0,50	0,50	0,50	0,70	0,70
Al (total)		0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06	0,06
Nb		–	0,04	0,05	0,05	0,05	0,05	0,05	0,06	0,06	0,06
V		–	0,04	0,07	0,08	0,08	0,09	0,10	0,10	0,10	0,10
Ti		–	0,04	0,04	0,04	0,04	0,06	0,06	0,06	0,06	0,06
N		0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010	0,010
B		0,0005	0,0005	0,0005	0,0005	0,0005	0,0005	0,0005	0,0005	0,0005	0,0005
C_{eq}	$\delta \le 15$	0,34	0,34	0,37	0,38	0,39	0,40	0,41	0,43	–	–
	$15 < \delta < 26$	0,35	0,35	0,38	0,39	0,40	0,41	0,42	0,44		
P_{cm}	$\delta \le 15$	0,20	0,20	0,21	0,22	0,22	0,23	0,24	0,26	0,29	0,32
	$15 < \delta < 26$	0,21	0,21	0,22	0,23	0,23	0,24	0,25	0,27	0,30	0,33

Notes: 1. For wall thickness δ exceeding 26 mm and for steel grades with strength higher than PCT550 the alteration of chemical composition is permitted subject to agreement with the Register.

2-10. Similar to those given in Table 4.5.2.1-1.

4.5.3 Mechanical properties.

4.5.3.1 The mechanical properties of steel shall meet the requirements of Table 4.5.3.1.

For rolled products, allowance for plastic strain shall be considered in the course of pipe manufacture. Unless otherwise specified, for a skelp the maximum permissible yield stress to tensile strength ratio shall be less than that for the pipe metal at least by 0,02.

Table 4.5.3.1

Mechanical properties of pipe metal

Grade	PCT PCTW	PCT32 PCT32W	PCT36 PCT36W	PCT40 PCT40W	PCT420 PCT420W	PCT460 PCT460W	PCT500 PCT500W	PCT550 PCT550W	PCT620 PCT620W	PCT690 PCT690W
Yield stress R_{eH} or $R_{p0.2}$, in MPa, min	235	315	355	390	420	460	500	550	620	690
Tensile strength R_m, in MPa	400–520	440–570	490–630	510–660	530–680	570–720	610–770	670–830	720–890	770–940
Yield stress to tensile strength ratio, max	0,90	0,90	0,90	0,90	0,92	0,92	0,92	0,92	0,92	0,92
Elongation A_5, %, min	22	22	21	20	19	18	18	18	16	15
Bending angle, °, min	120									
Group L (liquid)										
Impact energy, KV, in J, in the transverse direction, at T_B										
For all *D*	29	31	36	39	42	46	50	55	62	69
Critical brittleness temperatures, NDT, T_{kb}										
$\delta \le 20$ mm $20 < \delta \le 30$ mm $30 < \delta \le 40$ mm	NDT $\le T_B$ NDT $\le T_B - 10°$ NDT $\le T_B - 10°$, $T_{kb} \le T_B - 10°$									
Group G (gas)										
Impact energy, *KV*, in J, in the transverse direction, at T_B										
D ≤ 610 mm D ≤ 820 mm D ≤ 1120 mm	40 40 40	40 43 52	50 61 75	57 69 85	64 77 95	73 89 109	82 100 124	103 126 155	Subject to agreement with the Register	Subject to agreement with the Register
Critical brittleness temperatures, NDT, T_{kb}										
$\delta \le 20$ mm $20 < \delta \le 30$ mm $30 < \delta \le 40$ mm	NDT $\le T_B - 10°$ NDT $\le T_B - 20°$ NDT $\le T_B - 20°$, $T_{kb} \le T_B - 20°$									
DWTT: 85 % average fiber, 75 % minimum, at T_B										
CTOD, in mm, at T_B										
$\delta \le 20$ mm	0,10*	0,10*	0,10	0,10	0,10	0,10	0,15	0,15	0,15	0,20
$20 < \delta \le 30$ mm	0,10	0,10	0,15	0,15	0,15	0,20	0,20	0,20	0,25	0,25
$30 < \delta \le 40$ mm	0,15	0,15	0,20	0,20	0,20	0,25	0,25	0,30	0,35	0,35
Sulphide stress cracking resistance: no cracks after soaking in solution within 720 hours under pressure 85 % of the minimum rated yield stress.										

Table 4.5.3.1 – continued

Hydrogen-induced cracking/stepwise cracking resistance: CLR ≤ 15 % and/or TAS ≤ 20 %
N o t e s : 1. The required average values of impact energy are obtained at testing three specimens at the base temperature T_B. Reduction of impact energy up to 70 % of the required value is permitted on one specimen. 2. The required impact energy values in the longitudinal direction exceed 1,5 times impact energy values obtained in the transverse direction. 3. For *D* and δ dimensions beyond the specified limits the requirements shall be subject to agreement with the Register. 4. * – for class **L2**, **L3**, **G2** and **G3** pipelines only.

4.5.4 Condition of supply.

4.5.4.1 The condition of supply shall meet the requirements of Table 4.5.4.1.

4.5.4.2 There are following heat treatment procedures: normalizing (N), controlled rolling (CR), thermo-mechanical controlled processing (TMCP), quenching and tempering (Q + T) quenching from rolling heat and tempering (Q* + T).

4.5.4.3 The welded pipes are manufactured using bending and subsequent welding procedures. Seamless pipes are manufactured using cold and hot rolling procedures. As a rule, the pipes undergo cold expansion to achieve the required dimensions.

T a b l e 4.5.4.1

Condition of supply of rolled products and pipes

Steel grade	Condition of supply	
	δ < 12,5 mm	12,5 ≤ δ ≤ 40 mm
1	2	3
PCTW	any	N, CR, TMCP
PCTDW, PCTEW	any	N, CR, TMCP, Q + T
PCTFW	CR	TMCP, Q + T
PCT32W, PCTD32W	any	N, CR, TMCP, Q + T
PCTE32W	any	N, TMCP, Q + T
PCTF32W	CR	TMCP, Q + T
PCT36W, PCTD36W	any	N, CR, TMCP, Q + T
PCTE36W	CR	CR, N, TMCP, Q + T
PCTF36W	CR	CR, TMCP, Q + T, Q* + T
PCT40W, PCTD40W	any	TMCP, Q + T
PCTE40W	CR	TMCP, Q + T
PCTF40W	CR, TMCP, Q + T, Q* + T	

1	2	3
PCT420W, PCTD420W, PCTE420W, PCTF420W	CR, TMCP, Q + T, Q* + T	
PCT460W, PCTD460W, PCTE460W, PCTF460W	CR, TMCP, Q + T, Q* + T	
PCT500W, PCTD500W, PCTE500W, PCTF500W	CR, TMCP, Q + T, Q* + T	
Higher strength	TMCP, Q + T	

4.5.5 Inspection.

4.5.5.1 The requirements for rolled product surface quality, repair and removal of surface defects shall comply with 3.2.7, Part XIII "Materials" of the Rules for the Classification and Construction of Sea-Going Ships. Tolerances on rolled product thickness shall meet the standards recognized by the Register and be subject to agreement with the customer.

4.5.5.2 Non-destructive testing shall be carried out in compliance with the requirements of 4.3.8. The steel shall be free from any defects prejudicial to its use for the intended application. The manufacturer shall guarantee the absence of surface defects and internal discontinuities which dimensions prevent performance of non-destructive testing of welded joints.

4.5.5.3 Examination and verification of dimensions, geometry and mass of rolled products and pipes shall be carried out by the manufacturer. The availability of the Register certificate does not relieve the manufacturer of the responsibility if a material or product is subsequently found defective or does not comply with the agreed technical documentation or standards as regards its dimensions, geometry and mass.

The recommended requirements for dimension deviations and quality of rolled products and pipes are given in Tables 4.5.5.3-1 and 4.5.5.3-2, respectively.

Table 4.5.5.3-1

General requirements for rolled products

Characteristics	Scope of examination	Value
1	2	3
Deviations from flatness equal to 1 linear metre	100 %	Not more than 6 mm
Camber equal to 1 linear metre	100 %	Not more than 1 mm

Table 4.5.5.3-1 – continued

1	2	3
Rolled product continuity	100 %	Delaminations are not permitted if their size exceeds 80 mm in any direction or the area exceeds 5000 mm^2. Delaminations of any size are not permitted along the zones near edges
Surface quality	100 %	Cracks, skins, blisters,laps are not permitted. Separate roll marks, hairlines and rippling are permitted
Thickness δ*, in mm	100 %	7,5...40 with a tolerance – 0,4 / + (0,016 δ + 1,2)
Width W, in mm, depending on the pipe thickness and diameter	100 %	$W = \pi (D - \delta)$ with a tolerance – 20/0
* other thicknesses shall be subject to agreement with the Register		

Table 4.5.5.3-2

General requirements for the pipe dimensions

Characteristics	Scope of examination	Welded pipe	Seamless pipe[1]
1	2	3	4
Diameter pipe ends $D \le 610$ mm	R[2]	± 0,5 mm or ± 0,5 % D (whichever is greater), but max. ± 1,6 mm	
Diameter pipe end $D > 610$ mm	R[2]	± 1,6 mm	± 2,0 mm
Greatest difference in end diameters of one pipe (each pipe measured)	R[2]	12,5 % δ (δ – nominal wall thickness)	
Diameter pipe body, $D \le 610$ mm	R[2, 3]	± 0,5 mm or ± 0,75 % D (whichever is greater), but max. ± 3,0 mm	± 0,5 mm or ± 0,75 % D, (whichever is greater)
Diameter pipe body, $D > 610$ mm	R[2, 3]	± 0,5 % D, but max. ± 4,0 mm	± 1 % D
Out-of-roundness, pipe ends, $D/\delta \le 75$	R[2]	1,0 % D, but max. 8 mm	
Out-of-roundness, pipe ends, $D/\delta > 75$	R[2]	1,5 % D, but max. 8 mm	
Out-of-roundness, pipe	R[2, 3]	2,0 % D, but max. 15 mm	
Wall thickness, $\delta \le 15$ mm	100 %	± 0,75 mm	+12,5 % / – 5 % δ
Wall thickness, $15 < \delta \le 20$ mm	100 %	± 1,0 mm	+12,5 % / – 5 % δ
Wall thickness, $\delta > 20$ mm	100 %	+ 1,5 / – 1,0 mm	+10 % / – 5 % δ, but max. ± 1,6 mm

1	2	3	4
Total curvature	R[2]	≤ 0,2 % *L*[4]	
Local curvature	R[2]	≤ 1,5 mm for 1 m of *L*	
Ends squareness	R[2]	≤ 1,6 mm from true 90°	
Radial offset from the weld (LBW – laser-beam welding and HFW – high frequency welding)	R[2]	[5]	–
Radial offset from the weld (SWA – submerged arc welding)	R[1)]	≤ 0,1 δ, but max. 2,0 mm	–
Pipe length	100 %	Upon the customer's request	
Pipe weight	100 %	– 3,5 % / +10 % of nominal weight	

N o t e s : 1. The requirements for continuity and surface quality of seamless pipes are similar to those for a skelp (refer to Table 4.5.5.3-1)

2. R means random testing of 5 per cent of the pipes, but minimum 3 pipes per shift.

3. Dimensions pipe body shall be measured approximately in the middle of the pipe length.

4. *L* = the pipe length.

5. Thickness considering offset from the weld shall be within the limits of pipe wall thickness tolerance; in this case not less than actual minimum wall thickness of each pipe.

4.5.6 Documentation.

4.5.6.1 Every batch of skelps and pipes, which passed the tests shall, be accompanied by the Register certificate or manufacturer's document certified by the Register representative. The certificate, as minimum, shall contain the following data:

.1 order number;

.2 building project, if known;

.3 name, number, dimensions and mass of skelp/pipes;

.4 grade (mark) of steel;

.5 batch number or identification number, which enables to identify the supplied material.

4.5.6.2 The obligatory supplement to the Register certificate shall be the Manufacturer Quality Certificates attested by the duly authorized representative. The Certificate shall contain the results of chemical analysis, mechanical tests and, if required, ultrasonic testing of the rolled products (pipe). The form and contents of the Manufacturer Quality Certificate shall be agreed with the Register and the purchaser.

4.5.7 Marking.

Every rolled product and pipe shall have clearly visible manufacturer's marking and Register brand marked by the specified method and in specified location.

The marking, as minimum, shall contain the following data:

.1 name and/ or identification mark of the manufacturer;

.2 steel grade in accordance with the requirements of the present Section and Part XIII "Materials" of the Rules for the Classification and Construction of Sea-Going Ships;

.3 batch number, cast number or identification number in accordance with marking system of the manufacturer, which enables to identify the whole process of production of rolled products (pipe).

4.6 MATERIALS OF FLEXIBLE POLYMER-METAL PIPES AND THEIR END FITTINGS

4.6.1 General.

4.6.1.1 Selection of materials shall be carried out at the design stage of the flexible subsea pipeline structure to ensure its integrity, strength, reliability and durability, considering the potential changes of operational conditions and material properties during the design pipeline service life.

The possible changes of the flexible pipe shape and material properties during the whole sequence of operations associated with the pipeline storage, transportation and laying with use of reels (bundles) shall be also taken into account.

4.6.1.2 Properties of the flexible pipe layer materials for polymer-metal pipes shall correspond to their purpose and the operating conditions of the pipeline.

All the armoring layers (cage, radial armoring layer, axial armoring layer) shall be made of steel profiled strips (including an interlocked metallic construction) or wire. These layers shall ensure structural and technological strength of pipelines conveying hydrocarbons at prescribed minimum operating temperature and operational loads.

Inner (internal sheath, outer sheath, liner), separating (intermediate sheath) and insulation layers shall be made of polymer materials.

End fittings shall be fabricated from the steels meeting the requirements of 4.4.

4.6.1.3 All the materials used in the flexible pipe construction shall be certified for application in the corresponding environment (seawater) and the transported (natural gas, oil, etc.) medium within the range of design operating temperatures.

4.6.1.4 Service life of the flexible pipeline shall be specified taking into account the allowance for degradation of the mechanical properties of the material during the pipeline long-term service.

4.6.2 Polymer materials.

4.6.2.1 Nomenclature of the Register-controlled properties of polymer materials used in fabrication of the inner and intermediate layers of the flexible pipe is specified upon the design and purpose of the flexible pipes, proceeding from the following range of parameters:

Mechanical properties:

tensile strength;

ultimate elongation;

compressive strength;

shear strength;

bending strength;

modulus of elasticity;

impact strength;

hardness;

abrasion resistance;

residual compressive strain.

Physical properties:

density;

coefficient of thermal expansion;

melting point;

softening point;

range of working temperatures;

water absorption;

gas-/watertightness.

Other properties:

coefficient of thermal conductivity;

ageing;

creeping;

chemical resistance to the environment and the transported medium;

resistance to rapid depressurization;

endurance;

acceptable defects (notch sensitivity).

4.6.2.2 When the internal sheath of the flexible pipe is composed of multiple layers, the manufacturer shall experimentally confirm that the dissimilar material complies with the design requirements for the specified operating conditions and service life.

4.6.2.3 For polymer materials composing the insulation layers of the flexible pipes, the following shall be determined:

tensile strength;

ultimate elongation;
compression strength;
modulus of elasticity;
density;
coefficient of thermal conductivity (in dry and flooded conditions);
melting point;
softening point;
range of working temperatures;
water absorption;
endurance.

4.6.2.4 For sheath materials, the following shall be determined:
integrity properties;
melting point;
range of working temperatures;
endurance.

4.6.2.5 The effect of hydrostatic compression, water absorption and creeping shall be determined for buoyancy components.

4.6.3 Metal materials.

4.6.3.1 Nomenclature of the controlled properties of metal materials used in manufacture of the composite flexible pipes and end fittings includes the following.

Mechanical properties:
chemical composition;
metal macro- and microstructure;
tensile strength;
yield stress;
elongation;
Charpy impact strength for end fittings having a wall thickness over 6 mm at the minimum operating temperature below 0 °C;
hardness of base metal and welded joint metal;
results of a collapse test and drift test for all-metal pipes;
modulus of elasticity and Poisson's ratio;
data on corrosion resistance to transported medium and the environment (seawater);
data on erosion resistance to transported medium;
stress-cycle diagram during loading in air and corrosive media, which simulate the transported medium and seawater;
coefficient of thermal expansion.

Other properties:
chemical composition;
coefficient of thermal expansion;
corrosion resistance;
erosion resistance;
cyclic fatigue/fatigue endurance;
resistance to hydrogen cracking and sulphide corrosion cracking.

5 WELDING

5.1 GENERAL

5.1.1 The requirements of the present Section cover welding of subsea pipeline system structures made of steel, subject to the Register technical supervision and survey in accordance with the requirements of other Sections of the Rules.

5.1.2 Scope of technical supervision.

5.1.2.1 During manufacture of welded pipes and welding of pipelines and products for subsea transportation systems requirements of Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships and Part XIII "Welding" of the Rules for the Classification, Construction and Equipment of MODU/FOP shall be met having regard to the requirements of the present Section.

There are two different objects of technical supervision:

base metal of pipes, weldability tests;

technological procedures of welding and welded joints, realized during manufacture.

5.1.2.2 The scope of inspection during weldability tests of base metal is given in Table 5.1.2.2.

5.1.2.2.1 Testing for determination of standard mechanical properties of the welded joint.

Skelp samples are cut out from 1/4 ± 1/8 of the width. Samples from the pipe shall have the weld in the middle. Skelp welding is performed at the level of heat input agreed with the Register and usually corresponding to the pipes manufacture.

Tensile test of the skelp welded joint are carried out for the full thickness. Tensile test of the factory welded joint of pipe is carried out for the thickness less than 32 mm – straightening of billets, for greater thicknesses the tests on cylindrical specimens with straightening of the gripped billet parts only is allowed.

Full thickness specimens without straightening are tested for the face/root bend. Preliminary deformation between two planes of pipe specimens is allowed for the root bend.

Straightening of specimens for the side bend is not recommended.

5.1.2.2.2 CTOD test of the welded joint.

Skelp samples are cut out from 1/4 ± 1/8 of the width. Samples from the pipe shall have the weld in the middle. Skelp welding is performed at the level of heat input agreed with the Register and usually corresponds to the pipes manufacture. Two HAZ are usually inspected: close to the fusion line ("adjacent" to the welded joint) and close to the etching boundary ("distant"). Number of specimens at each temperature and for each HAZ zone under consideration shall be sufficient to gain three correct results. Generally, it is enough to test 7 specimens at each temperature with a notch at the "adjacent" HAZ and 5 specimens at the "distant" HAZ.

At the Register discretion the number of the cast plates subjected to testing and their thickness, as well as the test temperature may be changed depending on the intended use of steel or conditions of order.

Table 5.1.2.2

Scope of inspection during weldability test

Type of test	Location of samples on skelp/pipe and location of specimens cutting out	Minimum number of plates taken from cast/batch (pipes taken from cast/batch)	Minimum number of samples from sheet (pipe)	Minimum number of specimens from the plate (pipe)	Note	Total number of specimens from the cast (batch of pipes)
1	2	3	4	5	6	7
Welded joint testing (butt weld and longitudinal/spiral weld of pipe)						
Testing of standard mechanical properties (5.1.2.2.1)	From one end	1/1	2 pcs. from a plate for 1 butt weld, 1piece with a weld from the pipe		One heat input	
Welded joint tensile testing	Transverse to the weld, for the full thickness of skelp	1/1	2	2	Room temperature	2

1	2	3	4	5	6	7
Bend testing	Transverse to the weld	1/1	3	3	Face bend from two sides and side bend at room temperature	3
Impact testing	Transverse to the weld (notch along the weld metal, fusion line, heat affected zone at a distance of 2 and 5 mm from the fusion line)	1/1	12	12	Test temperature is assigned by the Register	12
Macrostructure examination, hardness testing according to Vickers	Template transverse to the weld	1/1	1	1		1
Welded joint CTOD testing (5.1.2.2.2 and 5.4.4)	From one end	3/1	8 pcs. from a plate for four butt welds; 4 pcs. with weld from a pipe	36: $(7+5)\cdot 3$	One heat input. At three temperatures assigned by the Register	36
Sulphide stress cracking resistance test	From one end	3/1	1	3		3
Hydrogen-induced cracking/stepwise cracking resistance tests	From one end	3/1	1	3		3

5.1.2.3 The scope of testing during approval of welding procedures shall meet the requirements of Section 6, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships considering requirements of the present Section. In this case, prior to production full-scale tests considered as principal ones shall be applied to the specimens welded in production conditions.

Unless otherwise specified, the test program for determination of standard mechanical properties shall be carried out (refer to Table 5.1.2.2) to measure the number and location of the test specimens for the impact bend tests. One set of specimens each of three specimens located at the weld centre, at the fusion line and at a distance of 2 and 5 mm from the fusion line, from each side of the weld shall be manufactured. Where metal thickness exceeds 26 mm the same set of specimens for the weld root side shall be additionally prepared. Three cylindrical specimens for metal weld tensile testing (from the centre of weld and along it) shall be additionally manufactured. Weld fracture tests may be carried out on the Register request on the "nick-break" specimens according to API 1104 standard with the analysis of defects in fracture according to the agreed procedure.

5.1.2.4 Weld metal CTOD tests shall be mandatory for welded joints of pipelines with reliability levels 2 and 3 (refer to 4.1.3). Weld metal CTOD tests for the pipelines of the 1 level of reliability may be carried on the Register request.

5.1.2.5 Corrosion tests shall be mandatory for the pipelines with reliability level 2 (refer to 4.1.3). In other cases tests may be carried out on the Register request.

5.1.2.6 The scope of testing of welded joints shall comply with the requirements for approval of technological procedure of welding, unless otherwise agreed. CTOD and corrosion tests of weld metal are carried out on the Register request. The scope of inspection of welded joints shall be not less than 1 per cent of the butt welds, unless otherwise agreed with the Register.

5.1.3 Technical documentation.

Technical documentation on welding submitted for approval under the subsea pipeline design is determined in 1.5. Technical documentation subject to review by the Register during approval of welding procedures and welding consumables shall meet requirements of 6.1.3 and 4.1.2.1, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships.

5.2 TECHNOLOGICAL REQUIREMENTS FOR THE MANUFACTURING PROCESS OF THE SUBSEA PIPELINES WELDED STRUCTURES

5.2.1 General requirements.

The present Section covers welding operations performed in workshop conditions, during laying or installation. Welding of carbon, low-alloy and clad steels shall be considered. The latter shall be used with the cladding inside for the pipelines with reliability level 2 (refer to 4.1.3) transporting aggressive media where the base metal – carbon and low-alloy steels – doesn't comply with the requirements for corrosion.

General welding recommendations shall be in compliance with Section 2, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-

Going Ships, as well as Section 2, Part XIII "Welding" of the Rules for the Classification, Construction and Equipment of MODU/FOP.

5.2.2 Welding techniques.

Unless otherwise agreed with the Register, the following welding procedures may be used:

manual metal arc welding with coated electrodes MMAW (SMAW:USA*)*;

self-shielded tubular-cored arc welding (FCAW:USA);

tubular-cored metal arc welding with gasshield (G-FCAW:USA);

metal inert or active gas welding MIG/MAG (GMAW:USA);

tungsten inert gas welding TIG (GTAW:USA);

automatic submerged arc welding (SAW:USA);

plasma arc welding (PAW:USA);

heigh frequency welding (HFW:USA).

In workshop conditions it is recommended to use an automatic submerged arc welding and arc welding with gas shield.

5.2.3 Production personnel and qualification of welders.

5.2.3.1 All operations in welding of structures of subsea transportation systems subject to the Register technical supervision shall be performed by the qualified welders only duly certified and having valid Welder Approval Test Certificate issued by the Register according to Section 5, part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships.

General requirements for the qualification of personnel shall comply with Section 2, Part XIII "Welding" of the Rules for the Classification, Construction and Equipment of MODU/FOP taking into account requirements of the present Section.

5.2.3.2 Through training and practice prior to certification tests a welder shall have understanding of:

fundamental welding techniques;

welding procedure specifications;

relevant methods of non-destructive testing;

acceptance criteria.

5.2.3.3 Welders certification tests are performed for the respective positions of weld during welding, material grades and welding procedures. Welders shall be certified for single side butt welding of pipes in the required principal position. Welders may be certified for part of the weld, root, fillers or cap by agreement. Repair welders may be certified for thickness defects repair provided only such weld repairs are made.

5.2.3.4 Certification shall be carried out using the same or equivalent equipment to be used during production welding (installation) and at actual premises at workshop, yard, and pipe-laying ship. Other conditions are allowed on agreement with the Register. Additional certification may be required if welding has been interrupted for a period more than 6 months.

5.2.3.5 Welders performing underwater welding using “dry welding” shall be first certified for surface welding and shall have received relevant training for underwater welding. Underwater welding certification tests shall be carried out for the specific certified technological procedure.

5.2.4 Base material. Weldability.

5.2.4.1 Welding of test assemblies for approval of base metal weldability shall be carried out by certified welders, heat input at sample welding shall comply with that used in production process. The Register has the right to require change of welding conditions of the certification test assemblies.

5.2.4.2 The geometry of the welded joint shall include one straight edge. Examples of edge preparation and structural components of the welded joint are shown in Fig. 5.2.4.2. On agreement with the Register, it is allowed to carry out weldability tests on the welded joints with an actual (production) geometry. In this case the number of tested specimens necessary for the correct results may be increased.

5.2.5 Welding consumables.

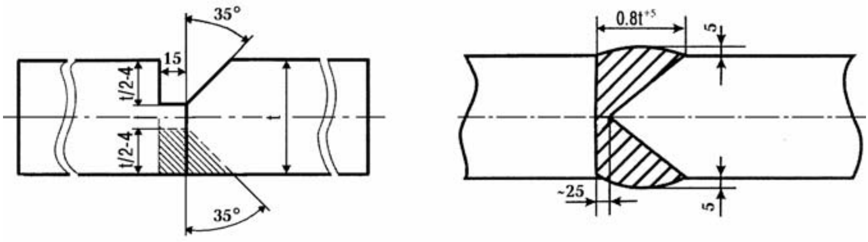
5.2.5.1 Welding consumables used for welding of structure of subsea transportation systems and subject to the Register technical supervision shall be approved by the Register, as a rule. Application and approval of welding consumables shall comply with 2.5, Part XIII “Welding” of the Rules for the Classification, Construction and Equipment of MODU/FOP considering the requirements of the present Section.

5.2.5.2 Welding consumables for pipe steel welding shall be selected similar to those intended for ship steel of the relevant strength level. Low hydrogen consumables of H5 or H10 category shall be employed for the pipe steel welding. Welding consumables for the pipelines with reliability level 2 (refer to 4.1.3) shall provide sufficient corrosion resistance of welded joints.

Special consideration shall be given to the ensuring safety against of cold cracking in the heat affected zones and in the weld metal during welding of higher and high strength steels. Besides, attention shall also be given the requirements for the relationship between the yield stress and tensile strength of weld metal and base metal.

5.2.5.3 Detailed instructions shall be drawn up for storage, handling, recycling and repeated drying of welding consumables. Special attention shall be paid to handling with welding consumables during underwater “dry welding”. Operating instructions shall be prepared for storage and handling of welding consumables on

Automatic submerged arc welding



Semi-automatic gas welding

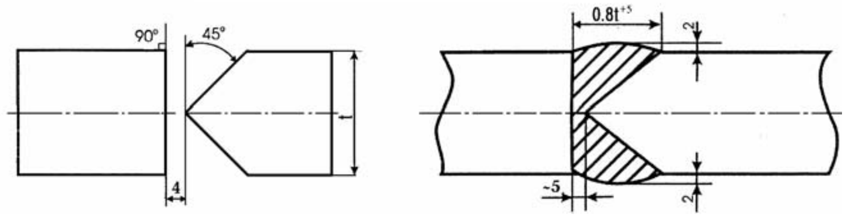


Fig. 5.2.4.2
Welded joints for weldability tests

support vessels and welding booths, as well as hermetization and transfer to the welding booth.

5.2.6 General requirements for welding operations.

5.2.6.1 Welding Procedure Specification (WPS) shall be prepared for all welding procedures covered by the present Section and subject to approval in accordance with the Register requirements. Welding Procedure Specification shall provide that all the specified requirements can be fulfilled.

5.2.6.2 Welding Procedure Specification shall as minimum contain the following information:

base metal grade in compliance with the Rules requirements and the pipeline class;

pipe diameter and wall thickness (or range);

edge preparation and welded join configuration, including tolerances;

welding procedure;

number and location of welders;

welding consumables (approved by the Register);

gas mixture and flow rate;
welding rod / wire diameter;
quantity of filler wire and flux;
welding parameters: current, voltage, type of current, polarity, welding speed, wire stick out and wire angle for each arc (or range);
number of welding arcs and heads (cold and hot wire addition);
welding position(s) and direction;
stringer or weaving;
nozzle size;
number of passes (for girth butt welds – before pipe-laying vessel move-up);
clamping (inside or external);
preheat temperature (if applicable);
time intervals between passes;
interpass temperature range;
post weld heat treatment.

5.2.6.3 Welding Procedure Specification for underwater "dry welding" shall also contain the following information:
water depth (minimum/maximum),
pressure inside the chamber,
gas composition inside the chamber,
maximum humidity level inside the chamber,
temperature inside the chamber (minimum/maximum),
length, type and size of the welding umbilical;
position for voltage measurements;
welding equipment.

5.2.6.4 Welding Procedure Specification for repair welding shall be prepared based on a welding procedure certification record for the type of weld repair to be applied. A repair WPS shall contain the following additional information:
method of removal of the defect, preparation of the weld area;
minimum and maximum repair depth and length;
type and scope of non-destructive testing to be performed after removal of defects and after weld repair.

5.2.6.5 Where the welding technological procedure changes the new tests shall be conducted in the following cases, unless otherwise agreed with the Register:
Base metal:
change from lower to a higher strength grade;
change in the supply condition;
change in the manufacturing process;

any increase of P_{cm} of more than 0,02, of C_{eq} of more than 0,03 and C content of more than 0,02 per cent;

change of manufacturer.

Geometry:

change in the pipe diameter (upon the Register approval);

change in the skelp/pipe wall thickness outside the interval from 0,75δ to 1,5δ;

change in the groove dimensions outside the tolerances specified in the agreed Welding Procedure Specification;

line-up clamps during pipe welding: change from external to internal or vice versa.

Welding process:

any change in the welding type;

change from single-wire to multiarc welding and vice versa;

any change in the equipment type and model (including underwater welding);

change in the arc parameters affecting the transfer mode or deposit rate;

change of type, diameter and brand of welding consumables;

change in the wire stick-out outside the tolerances specified in the agreed Welding Procedure Specification;

change in the gas shield mixture, composition and flow rate outside (more than 10 per cent);

change in the welding position to a principle position not complying with Table 5.2.6.5;

change in the welding direction from "vertical down" to "vertical up" or vice versa;

change in the number of runs from multi-run to single-run or vice versa;

change in the polarity;

change in the heat input during welding beyond the range of +/- 10 per cent, unless otherwise agreed with the Register;

change in the time intervals between passes beyond the limits approved by the Welding Procedure Specification;

decrease in the pre-heating temperature (if applicable);

any change in the cooling method resulting in shorter cooling time than certified by the test (installation welding);

any change in the post weld heat treatment procedure (if applicable);

stringer/weave more than three times the nominal diameter where weaving is not provided;

decrease in the number of welders.

Table 5.2.6.5

Certified welding positions

Welding position of test assemblies	Welding position which don't require additional certification
PA	*PA*
PC	*PA, PC*
PF/PG	*PA, PF/PG*
PC + PF/PG	*All*
H-L045	*All*

For underwater "dry welding" additionally:

any change in the pressure inside the welding chamber;

any change in the gas composition inside the chamber;

increase of humidity inside the beyond 10 per cent from the level of certification testing.

5.2.7 Welding of pipelines made of clad steel.

5.2.7.1 General requirements for welding of pipelines with internal cladding layer shall comply with 2.8, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships and 2.9, Part XIII "Welding" of the Rules for the Classification, Construction and Equipment of MODU/FOP, as well as considering the requirements of the present Section.

5.2.7.2 Production welding corrosion resistant cladding portion may be performed by one of the welding processes listed in 5.2.2, except self-shielded tubular-cored arc welding (FCAW) and high frequency welding (HFW). The welding shall be double sided, whenever possible. Welding of the root pass in single sided (field) joints will generally require welding with manual metal arc welding with coated electrodes (MMAW), tungsten inert gas welding (TIG); gas metal arc welding (GMAW).

5.2.7.3 The final weld bevel preparation shall be made by machining. Additional grinding is allowed providing that the grinding wheels shall not have previously been used for carbon or low-alloy steels. Thermal cutting shall be limited by the plasma arc cutting.

5.2.7.4 Stainless steel wire brushes shall be used for interpass cleaning of the corrosion resistant weld metal and clad material.

5.2.7.5 Welding consumables for welding of cladding layer shall be selected considering corrosion resistance of welded joint. The application of low-alloy welding consumables for welding of corrosion resistant materials is not permitted. If it is impossible to guarantee compliance with this requirement, the whole joint is welded by the corrosion resistant material.

5.3 INSPECTION OF WELDED JOINT

5.3.1 General requirements.

Requirements for the inspection of welded joints of subsea pipeline structures shall be assigned considering provisions of Section 3, Part XIII "Welding" of the Rules for the Classification, Construction and Equipment of MODU/FOP considering requirements of the present Section.

5.3.2 Scope of non-distructive testing and assessment of welded joint quality.

5.3.2.1 The scope of testing of subsea pipeline welded joints is set forth as follows:

visual examination– 100 per cent;

ultrasonic and radiographic examination – 100 per cent, total.

Then, the scope of testing using each method may vary from 0 per cent to 100 per cent depending on the welding technique (typical defects), as well as possible application (operational limitations) and employed equipment.

magnetic particle examination – 100 per cent, unless otherwise agreed with the Register.

5.3.2.2 For pipeline girth welds made of steel grade PCT550(W) but not higher, where the accumulated plastic strain resulting from installation and operation exceeds 0,3 per cent, as well as 0,4 per cent for pipelines made of higher strength steels, the safety assessment shall be carried out simultaneously with the risk analysis according to Section 10.

5.3.2.3 Quality assessment criteria for welded joints in the course of visual and magnetic particle examinations are given in Table 5.3.2.3-1. Quality criteria in the course of radiographic examination are given in Table 5.2.3.2-2. Any defects not listed in the tables are allowed on agreement with the Register.

5.3.2.4 The size of permissible defects in the course of ultrasonic examination conducted with the manual echo-technique using flaw detector of general purpose is given in Table 5.3.2.4.

5.3.2.5 It is allowed to use mechanical, automated and automatic ultrasonic or radiographic testing testing ensuring 100 per cent length of welded joint examination, providing that, upon the Register requirement, the scope of simultaneous use of radiographic and ultrasonic testing may exceed 100 per cent.

Non-destructive testing techniques with updating quality assessment criteria of welded joints considering type of equipment to be used shall be developed for each type of testing and approved by the Register.

Table 5.3.2.3-1

Quality assessment criteria for the visual and magnetic particle examinations of welded joints

Type of Defect	Criterion	
External profile	Welds shall have a regular finish and merge smoothly into the base metal, and shall not extend beyond the edge preparation by more than 3 mm (6 mm for automatic submerged arc welding)	
Reinforcement	Outside reinforcement: less than 0,2δ, maximum 4 mm Inside reinforcement: less than 0,2δ, maximum 3 mm	
Concavity	Outside concavity: not permitted. Inside concavity shall merge smoothly into base metal, and at no point shall the weld thickness be less than δ	
Displacement of edges	Longitudinal/spiral weld: less than 0,1δ, maximum 2 mm. Girth butt: less than 0,15δ, maximum 3 mm	
Cracks	Not permitted	
Undercuts	Individual	
	Depth d	Permissible length
	d > 1,0 mm	Not permitted
	1,0 mm ≥ d > 0,5 mm	50 mm
	0,5 mm ≥ d > 0,2 mm	100 mm
	d ≤ 0,2 mm	unlimited
	Accumulated length in any 300 mm length of weld: < 4δ, maximum 100 mm	
Surface porosity	Not permitted	
Arc burns	Not permitted	
Dents	Depth: < 1,5 mm, length less than 1/4*D* (*D* – pipe diameter)	

Table 5.3.2.3-2

Quality assessment criteria for the radiographic testing of welded joints

Type of defect	Criterion	
1	2	3
Separate defects		Maximum accumulated size in any 300 mm weld length
Porosity		
Scattered	Diameter less than δ/4, maximum 3 mm	Maximum 3 per cent of the area in question
Cluster	Pores less than 2 mm, cluster diameter maximum 12 mm, pore cluster area less than 10 per cent.	One cluster
Pores “on-line”	Diameter less than 2 mm, group length less than δ.	Two lines

1	2	3
Slag Isolated Single or parallel lines	 Diameter less than 3 mm Width less than 1,5 mm	 12 mm, maximum 4 off separated minimum 50 mm 2δ, maximum 50 mm
Inclusions Tungsten Copper, wire	 Diameter less than 3 mm Not permitted, if detected	 12 mm, maximum 4 off separated minimum 50 mm –
Lack of penetration	Length less than δ, maximum 25 mm. Width less than 1,5 mm	Less than δ, maximum 25 mm
Lack of fusion	Not permitted	–
Cracks	Not permitted	–
Weld concavity inside the pipe	See Table 5.3.2.3-1	–
Undercuts inside the pipe *Excessive penetration*	Depth less than δ/10, maximum 1 mm Less than δ/5, maximum 3 mm over the length to δ, maximum 25 mm.	Less than δ, maximum 25 mm Less than 2δ, maximum 50 mm
Notes: 1. Group of defects separated by less than the width of the smallest defect in a group shall be considered as one defect. 2. Isolated defects are separated by more than 5 times the size of the largest discontinuity. 3. Total accumulation of discontinuities in any 300 mm weld length (total size) – less than 3δ, maximum 100 mm excluding porosity; total weld length – less than 12 per cent. 4. Accumulation of discontinuities in the cross section of weld that may constitute wormholes or reduce the effective weld thickness with more than δ/3 is not acceptable. 5. No defects are allowed over the intersection of welds.		

Table 5.3.2.4

Quality assessment criteria for the ultrasonic testing of welded joints

Maximum permitted defect echo amplitude	Maximum length of permitted discontinuities L, mm
1	2
Base level[1] + 4 dB	$L \leq \delta/2$, maximum 10 mm
Base level – 2 dB	$L > \delta/2$, maximum δ or 25 mm
Base level – 6 dB	$L > \delta$, maximum 25 mm In the near-surface zones excluding the centre of the welded joint with thickness δ/3[2], the accumulated length of defects in any 300 mm of weld length less than δ, maximum 50mm

1	2
Base level – 6 dB	In the centre of the welded joint with thickness δ/3 the accumulated length of defects in any 300 mm weld length less than 2δ, maximum 50 mm
Transverse defects of any length (type “T” defects) are not permitted [3)]	
[1] The base (reference) level of sensitivity is obtained from 3mm ∅ side hole drilling in the reference specimen. Other methods for setting the base level are allowed if they provide the same sensitivity of testing. Requirements for specimens to alignment sensitivity shall be specified in the testing procedure. [2] Where the base metal thickness is less than 12 mm the mid-thickness of the welded joint is not considered. [3] Defect shall be considered as transverse if its echo amplitude transversely exceeds the echo amplitude from the weld longitudinally with more than 6 dB greater than the echo amplitude at an angle of 90 ± 15^0 to the longitudinal weld axis. Notes: 1. Where only one side of the welded joint can be tested the maximum permissible defect echo amplitude (the left column in the table) shall be reduced by 6 dB (twice). 2. Weld sections, defects interpretation that are doubtful and cannot be established with certainty shall be tested with the radiographic method and evaluated on the basis of the radiographic testing criteria. 3. Accumulated discontinuity length with echo amplitude equal of reference level – 6 dB and above shall not exceed 3*δ*, maximum 100 mm in any weld length of 300 mm nor more than 12 per cent of total weld length. 4. No defects are allowed over the intersection of welds.	

5.4 TESTING PROCEDURES

Testing procedures for the welded joints are similar to those for the base metal specified in Section 4, except ones described below.

5.4.1 Determination of sulphide stress cracking resistance.

Three welded specimens from the longitudinal weld of one pipe in a batch are subjected to test. Tests are carried out on a four-point bend full thickness specimen with the weld transverse and with reinforcement being soaked in the test solution within 720 hours under stress of 85 per cent of specified minimal yield stress for base metal of the pipe. The test solution and result assessment shall be the same as for the base metal.

5.4.2 Determination of hydrogen-induced cracking/stepwise cracking resistance.

Testing procedure shall be the same as for the base metal, test specimens are taken transverse to the weld with reinforcement, the weld shall be located in the middle of the specimen length.

5.4.3 Determination of capability to withstand plastic deformations during bend tests.

Bend tests shall be conducted the same way as for the base metal.

The weld reinforcement shall be removed flush with the surface of base metal. When reinforcement is removed, the specimen machining shall be made in the direction along its length.

5.4.4 Determination of CTOD value.

General procedures for billet straightening, testing and the size of welded joint specimens shall be the same as for the base metal. Special features of welded joints testing are stated bellow.

5.4.4.1 Notched specimens with a fatigue pre-crack are used for determination of CTOD values. Cutting out of specimens and notches in the weld metal and HAZ shall be made on the post heat material providing that the notch is located through thickness, and the direction of crack extension is along the weld centre line, unless otherwise specified in the normative documents on the metal products.

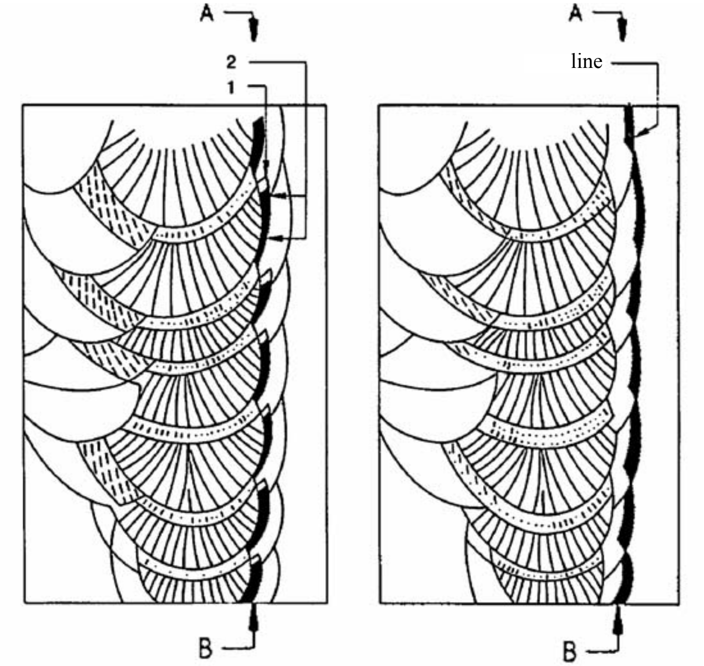
During certification of welding procedures where the CTOD testing is required the notch shall be located in accordance with the certification program approved by the Register, generally, in the centre of the weld.

5.4.4.2 During certification of material weldability the those HAZ structural components shall be tested that tend to exhibit the lowest crack resistance: zones with coarse-grain structure adjacent to the fusion line and zones with the incomplete structural transition or its absence adjacent to HAZ boundary with the base metal. The scheme of multi-run weld HAZ with the structural zones for which the CTOD value shall be determined is shown in Fig. 5.4.4.2.

5.4.4.3 Where the longitudinal welded joint of pipe with an actual geometry without straight edge is subject to testing the notch shall be marked so that it crossed the largest possible percent of the coarse-grained component at the fusion line (for testing of area with a coarse-grained structure adjacent to the fusion line boundary) or the ”distant” HAZ (for testing area with incomplete structural transition adjacent to the HAZ boundary with base metal) as shown in Fig. 5.4.4.3.

5.4.4.4 Simultaneously with preparation of welded specimens the transverse macrosections shall be cut out from the weld ends of each test assembly. They shall be subjected to metallographic analysis for checking the presence of metal zones inside the specimens central zone in sufficient quantity of 75 per cent of their thickness.

5.4.4.5 When marking-out the notch location in the weld specimen the end surfaces of the specimen (normal to the welding direction) shall be etched and the notch line shall be marked so that to clearly reveal them in the area in question.



a) double heated between change points (1) and at subchange point (2) in coarse-grained HAZ

b) line between HAZ areas, heated between change points and at subchange point

Note. AB – notch line.

Fig. 5.4.4.2
Multi-run weld HAZ. Investigated zones in question are marked

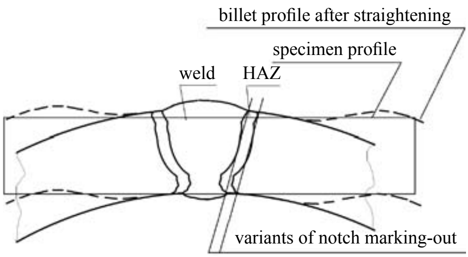


Fig. 5.4.4.3
Marking-out of pipe specimens

The angle between the notch line and the lateral surfaces of the specimen shall be within the range of 90 ± 5°, the deviation from this range shall be stated in the test report.

5.4.4.6 As far as test assemblies are tested after welding and have a high level of welding residual stresses the scope of requirements for the permissible deviations from the fatigue crack front straightness may be provided by means of the edge milling before crack growth on the part of the net section from 88 per cent including notch top with the accumulated plastic strain not more than 1 per cent. Multiple load application is allowed during edge milling. Edge milling depth measurement to evaluate plastic deformation shall be carried out with an accuracy not less ± 0,0025 mm.

5.4.4.7 Verification of treatment efficiency shall be conducted by measuring the fatigue crack front in the fracture.

An indirect method of yield stress determination shall be considered for the cases when a material with high structural inhomogeneity is tested and for which direct evaluation of σ_{ys} is not applicable. Due to the measurement results of the Vickers method HV in HAZ and in the base metal the yield stress σ_{yts} at a room temperature shall be determined; for HAZ see the following formula:

$$\sigma_{yts} = 3,28\ HV - 221. \qquad (5.4.4.7)$$

5.4.4.8 Metallographic analysis shall be carried out after tests to check whether the microstructure in question is located inside the control zone – the centre of crack front within 75 per cent of the specimen thickness. The fractured specimen is cut to polished sections as shown in Fig. 5.4.4.8 including the following operations:

cutting out of fractures from both ends of a specimen – from the weld metal and from the base metal;

fracture cutting across the fracture plane along the fatigue crack line. The low fracture part shall contain a fatigue crack of 2/3 of thickness;

making pollished sections and revealing heat affected zones, taking photographs.

Based on the metallographic results the location and length of the required microstructure inside the control zone shall be stated. At least 15 per cent of the microstructure shall be tested to ascertain the correctness of a test, unless otherwise specified by the Register.

Percentage determination of the structure in question along the crack front using analysis of the coarse-grained structure adjacent to the fusion line is shown in Fig. 5.4.4.8.

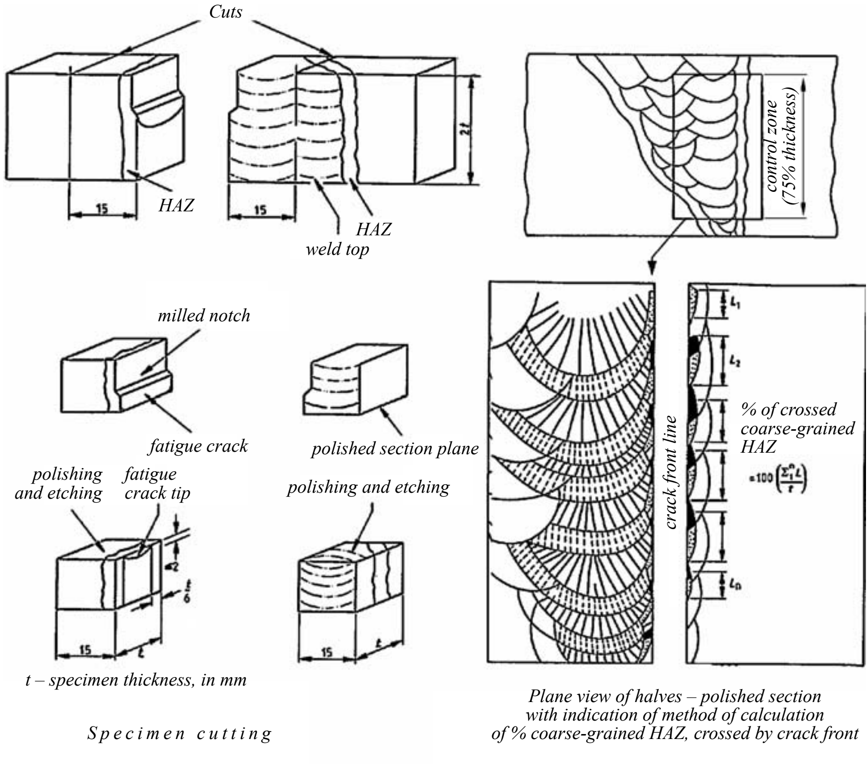


Fig. 5.4.4.8
Metallographic examination after tests

5.5 WELDING CONSUMABLES

5.5.1 General.

5.5.1.1 Welding consumables and their combinations, as a rule, approved by the Register may be used for welding of subsea pipelines. General provisions for approval of welding consumables shall be established in compliance with Section 4, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships, as well as according to 4.2, Part XIII "Welding" of the Rules for the Classification, Construction and Equipment of MODU/FOP considering requirements of the present Chapter.

5.5.1.2 The categories of welding consumables shall comply with those accepted in Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships. Other materials shall be allowed to use if it is proved that the properties of welded joints made of them comply with the requirements of the present Section.

5.5.2 Additional requirements.

Requirements for the weld metal and welded joint metal shall comply with the requirements for the base metal and be correspondingly differentiated for the categories of subsea pipelines. Requirements for the standard and special characteristics are given in Table 5.5.2. Impact and CTOD tests are carried out at temperature equal to base temperature T_B for the pipe steel grade to be welded.

5.6 APPROVAL TEST FOR WELDERS

5.6.1 The approval test for welders shall comply with Section 5, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships in respect of pipe welding. In the course of certification the full-scale specimens are used for welding, the heat input and other welding parameters shall be the most representative on agreement with the Register. The pipe metal and welding consumables for certification shall be approved by the Register.

5.7 APPROVAL OF WELDING PROCEDURES

5.7.1 Prior to preliminary approval of welding procedures the manufacturer shall submit documentation containing general information on technological procedure, data on the experience of its application as well as information about welded joint quality (according to the requirements of 6.1.3, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships).

5.7.2 Approval of welding procedure shall comply with Section 6, Part XIV "Welding" of the Rules for the Classification and Construction of Sea-Going Ships in respect of pipe welding considering the requirements of the present Section.

5.7.3 Welded joints submitted for approval shall undergo 100 % visual examination and measurement, ultrasonic or radiographic testing and surface crack testing. The scope of mechanical tests shall comply with 5.1.2 of the present Section. Special attention shall be given to the possibility of specimen straightening specified in 5.1.2.2.1 of the present Section and para 2 of Appendix 4.

Table 5.5.2

Physical and mechanical properties of welded joints

Welded steel	PCTW	PCT32W	PCT36W	PCT40W	PCT420W	PCT460W	PCT500W	PCT550W	PCT620W	PCT690W
1	2	3	4	5	6	7	8	9	10	11
Yield stress of the weld metal, MPa (minimum)	235	315	355	390	420	460	500	550	620	690
Tensile strength of the weld metal and transverse welded joint, MPa (minimum)	400	440	490	510	530	570	610	670	720	770
Vickers hardness of welded joint (maximum)	300	300	300	300	320	350	370	370	400	400
Bend angle, ° (min.)	120									
Impact energy KV, in J, on specimens transverse to the weld, at T_B										
Group L (liquid)										
For all D	29	31	36	39	42	46	50	55	62	69
Group G (gas)										
$D \le 610$ мм $D \le 820$ мм $D \le 1120$ мм	40 40 40	40 43 52	50 61 75	57 69 85	64 77 95	73 89 109	82 100 *	* * *	* * *	* * *
CTOD of weld metal and HAZ, mm, at T_B										
$\delta \le 20$ мм	–	–	–	–	0,10	0,10	0,10	0,10	0,10	0,15
$20 < \delta \le 30$ мм	–	0,10	0,10	0,10	0,10	0,10	0,15	0,15	0,20	0,20

1	2	3	4	5	6	7	8	9	10	11
30 < δ ≤ 40 мм	0,10	0,10	0,10	0,15	0,15	0,15	0,20	0,20	0,20	0,25
Sulphide stress cracking resistance: no cracks after soaking in a solution within 720 hours under stress of 85 per cent of the specified minimum yield stress.										
Resistance to hydrogen induced cracking/stepwise cracking: CLR ≤ 15 % and/or TAS ≤ 20 %										
N o t e s : 1. Average values of impact energy for three specimens at base temperature T_B are given. The impact energy may be reduced to 70 per cent of the required value for one of the specimens. 2. *Requirements on agreement with the Register. 3. *D* and δ beyond the specified limits shall be assigned on agreement with the Register.										

6 BALLASTING OF SUBSEA PIPELINES

6.1 GENERAL

6.1.1 Ballasting of the subsea pipeline is required for ensuring positive buoyancy compensation and on bottom stability by creating resistance to current and wave induced horizontal and vertical forces, as well as for ensuring protection against impacts during transportation, installation and operation.

6.1.2 Ballasting of subsea pipelines may be performed using continuous bulk concrete and asphalt concrete coatings applied on the insulation as well as by placing single cast iron, reinforced concrete and concrete weights.

6.1.3 Weight coating for ballasting and mechanical protection of pipelines shall comply with the following requirements:

have sufficient density and thickness to provide necessary negative buoyancy to the pipeline;

have sufficient mechanical strength to withstand damage during pipe transportation, installation and operation;

have sufficient durability, chemical and mechanical resistance to the sea water.

6.1.4 Split hinged or split saddle-shaped weights made of cast iron and reinforced concrete as well as other constructions approved by the Register may be used as single weights.

6.1.5 Pipeline weight including weight of the pipes, insulation, weight coating lining, if any, weights, etc. shall ensure the weight force sufficient for creating negative buoyancy to the pipeline. The value of this force shall be equal to the difference between the pipeline weight with all components and coatings in the air, and the weight of the water displaced by the pipeline.

6.1.6 Calculation of ballasting for the subsea pipeline shall be made as for the empty pipeline irrespective of the purpose (type of the conveyed medium) and environmental conditions in the area of the pipeline route. Weight of the medium conveyed is neglected.

6.1.7 Calculation of the ballast required and spacing between the single ballast weights shall be made based on the conditions for creating negative buoyancy to the pipeline, wave and current induced displacement resistance, as well as taking into account vertical forces occurring in curved sections of the pipeline. The required weight of submerged ballast Q_b, in kN/m, shall be determined by the formula

$$Q_b \geq \frac{F_g}{f_{fr}} \cdot k_{st} + (F_v + q_u + q_s) \cdot k_e - Q_p \qquad (6.1.7)$$

where F_g – total horizontal component of force action of waves and current determined in accordance with 2.5 and 2.6, in kN/m;

F_v – total vertical component of wave- and current induced force determined in accordance with 2.5 and 2.6, in kN/m;

f_{fr} – friction coefficient or tg φ, where φ – the smallest angle of soil internal friction along the pipeline route on sections where wave and current induced force is the biggest;

k_e – pipeline floating-up stability factor taken equal to 1,15 for pipelines of classes **L1** and **G1**; 1,2 for classes **L2** and **G2**; 1,25 for classes **L3** and **G3**;

k_{st} – pipeline shear stability factor taken equal to 1,1 for pipelines of classes **L1** and **G1**; 1,2 for classes **L2** and **G2**; 1,3 for classes **L3** and **G3**;

q_u – vertical force occurring during elastic bending of pipelines in the vertical plane, in kN/m;

q_s – vertical force occurring during lateral tensile pull in the curved pipeline, in kN/m;

Q_p – submerged pipe weight per unit length considering the weight of the corrosion protection and insulation (without weight of the transported medium), in kH/m.

Values of q_u and q_s shall be determined by the procedure agreed with the Register taking into account parameters of subsea pipeline route section (length and camber of the pipeline elastic deflection).

6.2 CONTINUOUS WEIGHT COATINGS

6.2.1 Concrete coating.

6.2.1.1 Design, calculation of principal parameters and application procedure of continuous concrete weight coating shall be based on the national state and branch standards, international standards related to concrete structures, such as EN 1992-1 Eurocode 2 (Design of concrete structures), EN 10080 (Steel for the reinforcement of concrete).

6.2.1.2 Initial parameters for the continuous weight coating are:

specific weight/weight in water;

coating thickness;

density;

compressive strength;

water absorption;

impact resistance;

bending resistance (flexibility).

6.2.1.3 The minimum thickness of the continuous coating shall be not less than 25 mm.

6.2.2 Raw materials for concrete manufacturing.

6.2.2.1 Properties and technical characteristics of raw materials for coating (cement, aggregates, reinforcement, water, etc.) shall comply with a performance specification, passport data and purchase specification.

6.2.2.2 Cement of domestic grades not less than 400 by GOST 10178-85, as well as similar cement grades meeting the requirements of EN197, BS 12, ASTM C 150, DIN 1164 or other national and international standards may be used for the concrete coating on agreement with the Register.

6.2.2.3 Concrete aggregates shall comply with the requirements of the national standards or regulations used in manufacture of the continuous concrete coatings.

The aggregates shall not contain harmful constituents in such quantities that could affect the concrete strength, for example, in pipeline bending or cause corrosion of reinforcing materials in case of water permeability of the concrete.

Use of aggregates with alkali-sensitive constituents is forbidden.

The maximum grain size and grading[1] curve of the aggregate shall comply with EN 206, ASTM C 33 or other standards.

The maximum grain size of gravel, iron or barium ore used as aggregates shall not exceed 10 mm.

6.2.2.4 Water for mixing concrete shall not contain harmful constituents in such quantities that could impair cement (concrete) curing, stiffening and strength or cause corrosion of reinforcing materials. Fresh water is normally used for concrete mixing.

6.2.3 Reinforced concrete coating.

6.2.3.1 Composition of the concrete, aggregate and water (refer to 6.2.2.1 to 6.2.2.4) shall be such that all the requirements for properties of stiffened and cured concrete, including its consistency, bulk density, strength and durability, as well as reinforcement protection against corrosion, shall be met.

Concrete shall comply with the following requirements:

minimum bulk density after curing shall be 2200 kg/m^3;

water absorption shall not exceed 5 per cent;

durability at the operating temperature shall be equal to the operational life of the subsea pipeline;

minimum compressive strength in a month after curing – 40 MPa.

Concrete compressive strength shall be determined at testing of check specimens taken from the batches and cut out directly from the concrete coating in accordance with the requirements of EN 206, ASTM C 42, BS 1881, BS 4019, BS 6089 or the national standards on agreement with the Register.

6.2.3.2 Steel reinforcement for the concrete coating shall consist of cylindrical cages mounted by resistance welding of longitudinal and hooped mild steel reinforcement or other reinforcement as required by the procedure approved by the

[1] G r a d i n g, g r a m - s i z e a n a l y s i s means the combination of methods for measurement of gram sizes in various media.

Register. Steel reinforcement may be applied in the form of thin bars, reinforcing mesh or helical reinforcement.

Diameter, surface condition, strength characteristics and marking of steel reinforcements shall comply with the requirements of international and national standards (e.g., EN 10080, BS 4482 and BS 4483, DIN 488).

Recommendations on size and setting of steel reinforcements are given in Table 6.2.3.2-1.

Table 6.2.3.2-1

Recommended diameters of reinforcement

Geometrical parameters	Longitudinal reinforcement	Hooped reinforcement	Reinforcement type
Bar diameter, in mm Bar distance (spacing), in mm Percentage of coating sectional area	6 – 8 75 – 400 0,08 – 0,2	6 – 12 75 – 150 0,5 – 1,0	Welded cage
Bar diameter, in mm Bar distance (spacing), in mm Percentage of coating sectional area	2 – 4 50 – 300 mm min. 0,08	2 – 4,0 65 – 100 mm min. 0,4	Wire mesh
Note. Alternative reinforcement materials, such as glass fiber may be used if they provide equivalent effective reinforcing.			

The bars for the values shaped like a welded cage shall be not less than 6 mm in diameter. The maximum spacing between hooped bars is 120 mm. The minimum cross-sectional area of longitudinal and hooped bars shall be 0,5 per cent and 0,08 per cent of the coating sectional area, respectively.

If a helical reinforcing mesh is used, the required number of layers depends on the concrete thickness and is determined from Table 6.2.3.2-2.

Table 6.2.3.2-2

Recommended number of layers of helical reinforcing mesh

Concrete thickness, in mm	Number of layers
< 60	1
61 – 100	2
101 – 140	3
> 140	4

6.2.4 Composite coatings.

6.2.4.1 On agreement with the Register, asphalt- or bitumen-based coatings may be used as weight coatings of the subsea pipelines.

6.2.4.2 In an asphalt mastic-based weight coating use may be made of the aggregates in the form of glass fiber and heavy-weight particles. The volume weight of such coatings shall be not less than 2,5 t/m^3.

6.2.4.3 An asphalt mastic-based weight coating shall be applied on the pipeline surface in hot state at temperature not higher than 140 °C. Upon application of the compound a layer of glass reinforced plastic is wound thereon, then the coating is pressed with pneumatic hammers and cooled down to the environmental temperature.

7 CORROSION PROTECTION

7.1 GENERAL

7.1.1 The entire external and internal surface of the steel subsea pipeline shall be protected with the corrosion-resistant coating. The type of the protective coating shall be selected depending on the pipeline structure and adopted method of laying. Elastic and strong coatings shall be used in cases where the pipeline is laid from a pipe-laying vessel by S- or J-method as well as by towing afloat with subsequent flooding. Where the pipeline is laid by seabed pull, the coating shall be strong enough to prevent damage from friction against the seabed soil, which may be rocky. The coating shall be applied in factory conditions, on special site or on board a pipe-laying vessel.

7.1.2 An insulating corrosion-resistant coating shall comply with the specification requirements during the entire lifetime of the pipeline considering of the following properties: breaking strength, elongation at the operational temperature, impact strength, adhesion to steel, the maximum area of sag in seawater, resistance to fouling, resistance to indentation.

7.1.3 The requirements for insulation of welded joints, valves and fittings shall not be lower than those for the pipe insulation.

Insulation of connections of electrochemical protection devices and instrumentation, as well as insulation restored in damaged areas shall provide reliable protection of the pipe metal against corrosion.

7.1.4 Special arrangements shall be made to prevent mechanical damages to the protective insulating coating during transportation, handling operations and storage of pipes.

7.1.5 The metal components of flexible subsea pipelines, in contact with seawater (connecting end fittings), shall be protected against the external corrosion by means of a combination of methods: the corrosion-resistant coating and electrochemical (cathodic protection or sacrificial anode system) protection.

7.2 PROTECTION AGAINST INTERNAL CORROSION

7.2.1 For steel subsea pipelines and flexible pipe metal components (end fittings, cage) conveying corrosive media, arrangements shall be made to protect the internal surface of the pipeline against corrosion. Referred to such arrangements are:

increase of the pipe wall thickness with regard to corrosion allowance;

application of corrosion-resistant materials meeting the requirements of 4.3.9.5.1 and 4.3.9.5.2 for steel pipes, end fittings and cages of flexible pipes;

application of the corrosion-resistant coating on the internal surface of the pipes;

pre-treatment of hydrocarbons before transportation in order to remove water or other substances contributing to corrosion;

inhibition of hydrocarbons.

7.2.2 The method of corrosion protection selected shall meet the pipeline operating conditions and comply with the requirements of the performance specification. Calculation results confirming the efficiency of the protection shall be approved by the Register.

7.2.3 The wall thickness of subsea pipelines shall be increased with regard to corrosion wear to compensate the loss of the pipeline strength resulting from the wall thinning due to overall uniform corrosion.

7.2.4 A necessity of introduction of the corrosion allowance and its value are based on consideration of the following factors:

design lifetime of the pipeline, corrosion activity of the transported medium and operating conditions;

suggested type of corrosion;

efficiency of additional measures on the pipeline protection to mitigate the corrosion processes, e.g., by chemical treatment of the transported media, coatings, etc.;

sensitivity of the internal corrosion instruments, frequency of inspections and checks;

consequences of accidental leakage of the transported media, reliability and safety requirements;

efficiency of the pipeline pressure monitoring system, etc.

7.2.5 The minimum corrosion allowance for carbon steel pipelines conveying non-aggressive media shall be not less than 1 mm. For pipelines conveying corrosive media, in particular liquid and gaseous hydrocarbons, likely to contain water, corrosion allowance shall be minimum 3 mm. For subsea pipelines made of stainless steel and alloys no corrosion allowance is required.

7.2.6 The following parameters shall be taken into consideration in case of using the pipelines made of stainless steel and alloys:

strength properties;

manufacturability, including weldability;

corrosion resistance, including intercrystalline corrosion.

7.2.7 When selecting corrosion-resistant coating, the following factors shall be taken into account:

chemical compatibility with hydrocarbons to be conveyed and with other substances, including probability of inhibition (refer to 7.2.8), likely to be contacted during instalation, laying and operation;

resistance to erosion effect of the transported media and to mechanical damages during cleaning of the internal surface of pipelines;

resistance to quick decompression;

availability of the reliable quality control systems of the basic coating of pipes and coating in the area of field joint.

7.2.8 For temporary corrosion protection of internal surfaces during storage, transportation and prior to filling, the end caps in the form of plugs and sockets shall be used, the preservative mixture shall be applied, the pipeline shall be filled with inhibited fluid.

7.3 PROTECTION AGAINST EXTERNAL CORROSION

7.3.1 Coatings.

7.3.1.1 In order to protect the subsea pipeline against external corrosion, a corrosion-resistant insulating coating (normally multilayer) approved by the Register shall be applied. Where necessary, the external coating shall have an outside layer for protection against mechanical damage during tie-in operations and laying in/on hard seabed. Field joint (weld) shall be protected with one- or multilayer coating.

7.3.1.2 The external coating shall be selected based on consideration of the following factors:

water permeability, solubility of gases and salts, adhesion, porosity, etc;

physical (mechanical), chemical and biological resistance, its diminution during storage and operation;

compatibility of the coating application, including areas of field joints, with construction, assembly and repair in field conditions;

compatibility with a concrete coating, if any;

compatibility with cathodic protection;

compliance with the requirements for insulating coating in case of performance as the latter;

adherence to occupational safety and health requirements with regard to harmful conditions of preparation, application and conditioning.

7.3.1.3 Physical and mechanical properties of the coating shall be given in the purchase specification. Referred to such properties are:

the maximum and the minimum thicknesses;

density;

adhesion;

tensile stresses and elongation;

impact resistance;

cathodic resistance;

transverse resistivity;

bending;

thermal conductivity;

electrical resistance;

wear resistance;

resistance to hydrostatic pressure;

curing behaviour.

7.3.1.4 Manufacturing specification for coating shall contain the following:

coating material (specification for material of the coating to be applied, including certificates for material property tests);

surface preparation (manufacturer's technical requirements for surface preparation class prior to coating application);

coating application (application process with indication of main parameter values: air temperature and relative humidity, pipe surface temperature, application time, dry and wet layer thickness of the coating; material consumption; time of the coating layer drying and its total conditioning depending on the air temperature, etc.);

inspection and testing (specification for the coating to be applied, including certificates of tests to determine the coating parameters referred to in 7.3.1.3 above);

coating repairing process;

transportation and storage of coated pipes (guidelines and instructions on transportation and storage of pipes).

7.3.1.5 Pipe surface preparation prior to coating application shall include: elimination of defects (weld leveling, rounding of sharp edges to a radius not less than 2 mm), cleaning from oil and other contaminants, as well as from slag and corrosion products.

Oil and other contaminants shall be removed with white spirit and water-based washing solutions. Scale and corrosion products shall be removed with the aid of abrasive-jet blasting units with subsequent removal of dust.

Coating shall be applied not later than in 4 hours after abrasive-jet blasting in the open air and not later than in 24 hours in enclosed spaces.

7.3.1.6 All coatings shall be subjected to inspections and tests, including:

visual examination;

thickness measurement;

determination of coating integrity;

adhesion tests of separate pipes.

7.3.2 Special coatings for riser and shore crossing.

Peculiarity of corrosion protection of risers and shore crossings depends on the division into the splash, atmospheric and submerged zones.

Corrosion-resistant coating in the splash zone shall be designed for adverse corrosion conditions in this zone, particularly during transportation of heated fluids, for example, oil and petroleum products. Corrosion-resistant coating in this zone shall be protected against mechanical damage caused by hydrodynamic effects, ice or floating facilities.

For each specific riser or shore crossing, the division into corrosion protection zones (submerged, splash and atmospheric) shall be assumed depending on structural peculiarities of the riser or shore crossing and prevailing environmental conditions. For each of the above zones, different types of corrosion-resistant coating may be used, provided they are compatible and meet the requirements of 7.3.1.3 and 7.3.1.4.

7.3.3 Field joint coatings.

7.3.3.1 For pipes with concrete coating or thermally insulated coating, the field joint coating shall have a multiple-layer structure made up of corrosion-resistant protective coating and an in-fill. The latter shall provide a smooth transition of the field joint coating to the pipeline basic coating.

For thermally insulated pipelines, risers and shore crossings, the in-fill material shall have adequate insulating properties.

7.3.3.2 For the selection of field joint coating, the requirements of 7.3.1.2, 7.3.1.3, 7.3.1.5, 7.3.1.6 and 7.3.2 shall be met taking into account that welding seams are much susceptible to corrosion attacks. It is preferable to use multiple-layer cold coatings and special sleeves for the protection of field joints.

7.3.3.3 All field joint coating work shall be carried out in accordance with the procedure approved by the Register.

7.3.4 Cathodic protection.

7.3.4.1 Cathodic protection shall be used to protect subsea pipelines from corrosion wear. Refusal to use cathodic protection for subsea pipeline, taking into account that other means of corrosion protection are available, shall be subject to agreement with the Register.

7.3.4.2 Technical documentation on cathodic protection of subsea pipeline shall contain the following:

layout drawing of the cathodic protection stations, including the location of all test points;

specifications and data sheets of all the necessary equipment, i.e. transformer supports, electric cables and their protective devices, test points, etc.;

specifications for installation of the cathodic protection system;

specifications for start-up and acceptance tests;

operating and maintenance instructions for the cathodic protection system.

7.3.4.3 In order to provide adequate cathodic protection, a carbon steel subsea pipeline shall have a protection potential between – 0,90 and – 1,1V measured relative to a silver/silver chlorine/seawater (Ag/AgCl/seawater) reference electrode. These potentials relate to saline mud and seawater with salinity within 32 to 38 ‰. Under anaerobic conditions, e.g., saline seabed mud, and a possibility of microbiologically assisted corrosion, a protection potential value shall be assumed equal to – 0,90 V. For protection of stainless steel, a polarized potential more negative than – 0,55 V shall be used.

7.3.4.4 The negative limit of protective potential shall be determined to eliminate hydrogen-induced cracking and corrosion fatigue of the pipeline base material and welds.

7.3.4.5 To measure potential between the pipeline surface and seawater, the following types of reference electrodes may be used:

saturated calomel (KC1); saturated copper-sulfate;

silver-silver chloride/seawater (Ag/AgCl/seawater);

high-purity zinc (minimum 99,9 per cent of zinc with iron content not exceeding 0,0014 per cent) alloy/seawater; anode zinc alloy/seawater.

7.3.4.6 The value of cathodic protection current density shall be determined for:

polarization of subsea pipeline (initial, mean and final current density);

polarization maintenance (protective current density);

depolarization.

Initial current density shall be equal to 10 per cent of the protective current density. Current density control depending on subsea pipeline surface condition and environmental conditions shall be provided by cathodic protection system.

7.3.4.7 The cathodic protection system of subsea pipelines may be provided with one or two cathodic protection stations located on one or both ends of the pipeline. Installation and testing of the cathodic protection system shall be subject to the Register technical supervision.

7.3.4.8 The anode materials for the cathodic protection system may be mixed oxides, activated titanium and platinized niobium, tantalum or titanium, platinum-tantalum alloys, niobium or titanium alloys, including platinized titanium alloy, highly-conductive metal with the oxide coating layer, lead-silver alloys (lead with addition of 1 to 2 per cent of silver).

7.3.4.9 Selection of the type of rectifier for a cathodic station shall be based on the current and voltage values, which are determined by the calculation during design. Rectifiers shall be of a constant current and potential controlled type, and manually controlled, except for the special applications. Cables shall be provided with insulation suitable for marine environment and an external jacket for adequate protection against mechanical damages. The electrical connection between the anode and anode cable shall be watertight and mechanically sound.

7.3.4.10 The cathodic protection system shall be designed and based on the following conditions:

cathodic protection calculation results shall specify the end values of the following values and parameters: total protective current and design voltage; type, number and lifetime of anodes; types and cross-sections of cables; anode line circuits; type of cathodic protection stations;

the cathodic protection calculation is based on the condition that the recommended arrangement of anodes shall provide equal distribution of potentials on the surface protected;

cathodic protection system shall be calculated for two stages of its operation: for a period of cathodic deposit to be formed on the surface to be protected and for operational period.

Where, due to shielding by other components of the system, some areas are not adequately protected, and installation of additional external anodes is not possible, use of a combined protection by cathodic protection system and sacrificial anode system is allowed.

It shall be taken into account that distribution of potentials is different for impressed current protection and sacrificial anode protection system is different: in the first case the anode potential is more positive, in the second case – negative.

The transformer-rectifier current output shall be at least 25 per cent over the current required for the protection of the pipeline during its entire lifetime.

7.3.4.11 The cathodic protection system shall be buried on-shore or placed on the seabed.

The anodes shall have sufficiently low electrical insulation resistance in the electrolyte (seawater) to provide low electrical resistance in the current circuit of the cathodic protection in order that the output voltage of the transformer-rectifier at the maximum current output does not exceed 50 V for safety reasons.

The total anode material weight shall be greater than the anode material consumed during the design lifetime at the maximum current output of the transformer-rectifier.

7.3.4.12 In case of inert composite anodes (e.g., platinized titanium anodes), the anode operating voltage shall be lower than the breakdown voltage of the external anode layer.

In all cases, the distance of the anode from the pipeline shall be selected minimum in order that the protective potential of the pipeline section close to the anode is higher than the negative limit of the protective potential (refer to 7.3.3.4).

The anode current density shall be lower than the maximum current density of the relevant anode material recommended by the manufacturer.

7.3.4.13 Where the cathodic protection system is used for protection of subsea pipelines and risers, the requirements for electrical insulation from adjacent structures (platforms, pipe racks) shall be met (use of insulating flanges). The same applies to the pipeline section where it comes out of the sea to the shore.

7.3.4.14 Electrochemical protection shall be put into operation not later than during 10 days after the date of completion of the pipeline laying.

7.3.5 Sacrificial anode system.

7.3.5.1 Technical documentation on sacrificial anode system submitted to the Register for consideration shall contain the following:

technical requirements, drawings and specifications for the manufacturer's sacrificial anodes;

electrochemical test results (for electrochemical capacity in seawater, changing of closed circuit potential in seawater);

calculation of sacrificial anodes mass and number depending on the design pipeline lifetime;

calculation of sacrificial anode resistance;

calculation of the area to be protected and the protection current;

technical conditions, drawings and specifications for sacrificial anodes installation and fastening.

7.3.5.2 When selecting materials for sacrificial anode manufacture, preference shall be given to alloys having the following parameters:

high utilization factor of soluble metal;

low anode polarizability;

stability of electrochemical characteristics in time;

absence of conditions for formation of anode solution products and films on the sacrificial anode surface.

7.3.5.3 Selection of sacrificial anode material shall take into account the following:

sacrificial anode working conditions if immersed in seawater, seabed soil or in saline mud;

design theoretical ampere-hour efficiency;

required value of the pipeline protection potential (refer to 7.3.5.8);

design lifetime of the pipeline (sacrificial anodes);

environmental temperature, pipe walls and sacrificial anodes.

Aluminum alloys for sacrificial anode manufacture shall contain activating alloying additions limiting or preventing formation of an oxide surface layer. Zinc alloys shall be used to exclude hydrogen depolarization.

7.3.5.4 For pipelines with thermal insulation the sacrificial anodes shall be installed so as to eliminate their heating. When heated liquids are transported through the subsea (in salty water) pipeline and the sacrificial anode temperature exceeds 50 °C, installation of zinc anodes is prohibited.

7.3.5.5 The outside diameter of sacrificial anodes of the bracelet type is recommended to select equal to the diameter of the pipeline with weight coating and/or thermal insulation. When outside diameter of the sacrificial anode of the bracelet type is greater than that of the pipeline with weight coating and/or thermal insulation, as well as without weight coating and/or thermal insulation, the side surfaces of sacrificial anodes of the bracelet type shall be made in frustaconical shape.

7.3.5.6 The sacrificial anodes shall be mounted on the pipeline so as to avoid any mechanical damage of pipes and anodes, electrical discontinuity of sacrificial anodes with the pipeline, discontinuity of insulating and weight coatings. After each installation of sacrificial anode the circuit continuity shall be checked instrumentally.

Steel reinforcing of concrete weight coating shall not be in electrical contact with the pipe or anode.

7.3.5.7 The ways of anode installation on the pipeline, as well as the technological procedures of welding for sacrificial anodes and doubler plates shall be approved by the Register. Welding of the sacrificial anodes and their doubler plates to the pipeline welds is prohibited, the minimum distance from the welding area of the anode or the doubler plate to the pipe weld shall be 150 mm.

7.3.5.8 Continuous distribution of potentials on the entire surface of the subsea pipeline over the entire length shall be provided during the whole lifetime of the pipeline. The minimum and the maximum values of protection potentials for seawater are given in Table 7.3.5.8. The given potentials are valid for seawater with salinity 32 to 38 ‰ at a temperature between 5 and 25 °C.

Table 7.3.5.8

Values of protection potentials for subsea pipelines

Probe electrode	Minimum protection potential, V	Maximum protection potential, V
Saturated copper-sulphate	– 0,95	– 1,10
Silver chloride	– 0,90	– 1,05
Zinc	+ 0,15	0,00

8 PIPELINE INSTALLATION AND TESTING

8.1 GENERAL

8.1.1 Installation, laying and testing of subsea pipelines shall be carried out with due regard to the conclusions and recommendations obtained upon results of risk analysis of the above processes, based on the requirements of Section 10 and Appendix 3. Section related to risk analysis shall be included in the documentation submitted to the Register for review and approval – refer to 1.5.

8.1.2 Prior to installation, laying and testing of subsea pipelines, the following shall be submitted to the Register for review:

.1 technical documentation listed in 1.5.7, 1.5.3.2.1, 1.5.3.2.5;

.2 process documentation on:

storage, transport and handling of pipes;

assembly and welding of pipes and strings;

non-destructive testing, including visual examination;

application of coatings and insulation on weld area of pipes or strings;

repair and renewal operations for correction of defects detected.

8.1.3 Prior to installation and laying of subsea pipelines, pipe-laying vessel equipment (welding equipment, positioning systems, tensioning machinery) or other equipment used for other laying methods shall be surveyed by the Register.

8.2 PIPELINE ROUTING

8.2.1 The pipeline route and value of burial into the seabed soil shall be selected so that to minimize influence of lithodynamic processes on the operability and reliability of the pipeline.

8.2.2 Where possible, the subsea pipeline route shall avoid permafrost zones.

8.2.3 To minimize contact of the pipeline with the keels of drifting ice formations and stamukhas it is reasonable to lay the pipeline route along the line of maximum depth and parallel to the prevailing drift direction of ice formations.

8.2.4 Shore crossing of the pipeline in the areas with the seasonal ice cover shall be designed as a hydraulic structure capable to take up ice load (local and global) at effective ice thickness with 10^{-2} 1/year probability. It is recommended that the contact area of a protective structure with ice shall be inclined to the horizontal plane at an angle to the horizon not exceeding 45° within the height range from the mean water level to $\pm$ double effective ice thickness.

8.2.5 Selection of the route shall minimize environmental risks and risks for the sea bioresources.

8.2.6 In the course of subsea pipeline routing, on the sections of significant depth gradient, in order to avoid hazardous pipe bending the following requirement shall be meet:

$$R_l > 1000 \cdot D_a \qquad (8.2.6)$$

where R_l – radius of the pipeline route curvature (horizontal and vertical planes), in m;
D_a – outside diameter of the pipe, in m.

Application of radius values smaller than those specified in Formula (8.2.6) during pipeline routing shall be subject to special agreement with the Register.

8.2.7 It is recommended to move subsea pipeline shore crossing away from a river mouth in freezing and arctic seas to prevent possible erosion of the buried pipeline by vertical water flows at intense ice melting.

8.2.8 Prior to installation and laying of the subsea pipeline, additional studies along the pipeline route shall be carried out, when:

the period of time since the engineering survey to commencement of installation work is two years and above;

significant changes in seabed soil conditions is likely to have occurred;

the expected pipeline route is in areas exposed to hazardous effects, e.g., seismically dangerous;

new units, facilities, pipelines, etc. are present in the area.

8.2.9 During seabed preparation the following measures shall be taken prior to the pipeline laying along its route:

prevention of undesirable processes of any seabed soil erosion or drift;

removal of potentially hazardous facilities;

design of crossings with the preliminary laid pipelines and cables, pipeline shore approach;

underwater excavation.

8.2.10 Before laying the pipeline in a preliminarily excavated trench, the contractor with participation of a surveyor to the Register shall check invert levels of the trench longitudinal profile. Excess in the trench bottom depth shall not exceed 0,5 m. The pipeline shall be prepared for laying by completion of an underwater trench excavation.

8.2.11 Laying of the pipeline on the seabed for subsequent burial thereof shall be allowed only provided that preliminary checking measurements and calculations show that bending radii of the pipeline will be not less than the minimum permissible values based on strength requirements.

A concrete-coated pipeline may be laid after the concrete is cured to the design strength.

8.2.12 All preparation work on design of crossings whith pipelines and cables shall be carried out in compliance with a specification detailing the measures taken to avoid any damage to crossing installations.

The specification shall contain the requirements for:

the minimum distance between the existing installation and the pipeline;

co-ordinates of crossing;

marking of the pipeline route;

position and orientation of existing installations on both sides;

lay-out and profile of crossing;

anchoring of the pipeline and its structures;

installation of bearing structures (supports) or gravel beds;

measures to prevent erosion of the pipeline structural members;

monitoring;

tolerances;

any other requirements for pipeline structure and crossing.

8.3 ADDITIONAL MEASURES FOR PROTECTION OF THE PIPELINE IN THE AREAS OF INTENSE ICE GOUGING

8.3.1 In sea areas with seasonal ice cover (freezing seas: the Caspian Sea, the Baltic Sea, the Sea of Okhotsk, etc.) and on the shelf of Russian Arctic, where presence of ice gouging is revealed instrumentally (underwater TV survey, sonar survey, diver survey), the pipeline shall be buried into the seabed soil.

8.3.2 To determine maximum depth of the subsea pipeline laying along the pipeline route in the areas of intense ice gouging the following parameters shall be specified:

h_s – sea depth with regard to tide, in m;

h_k – mean value of keel draft of drifting ice formations, in m;

σ_h – mean-square deviation of keel draft of drifting ice formations, in m;

T_R – mean time of ice formation existence within a year (days);

V – average drift velocity of ice formations (km/day);

N – average number of drifting ice formations per 1 km^2 during ice period.

The said parameters shall be determined as a result of investigations for the particular sections of the pipeline route, within which the parameter values are assumed as constant.

Parameters h_k, σ_h, T_R, V, N shall be determined based on the data of long-term in-situ observations and measurements carried out along the pipeline route (route sections) for at least 5 consecutive years.

8.3.3 Maximum burial depth of the pipeline into the seabed soil at the particular ice formation properties stated in 8.3.2 shall be calculated in sequence as stated below.

8.3.3.1 Non-dimensional values of $\bar{h}$ and λ characterizing ice formation draft shall be determined by Formulae (8.3.3.1-1) and (8.3.3.1-2) respectively:

$\bar{h} = h_k/h_s$ – mean draft ratio of the drifting ice formation; (8.3.3.1-1)

$\lambda = \sigma_h/h_k$ – coefficient of variation of the drifting ice formation. (8.3.3.1-2)

8.3.3.2 The unit exceedance probability P_0 of the sea depth by the ice formation draft shall be determined from Table 8.3.3.2 by linear interpolation based on $\bar{h}$ and λ parameters.

Table 8.3.3.2

Probability P_0

P_0		$\bar{h}$				
		0,2	0,4	0,6	0,8	0,9
λ	0,2	0,0	0,0	0,002119	0,11043	0,473398
	0,4	0,0	0,002369	0,063711	0,238911	0,446778
	0,6	0,000069	0,023542	0,130977	0,280456	0,420216
	0,8	0,001554	0,055157	0,169684	0,289655	0,393701
	1,0	0,006738	0,082085	0,188247	0,286505	0,367879

8.3.3.3 Parameter *a* determined on the basis of the ice formation keel contact with the pipeline with 10^{-2} 1/year probability shall be determined by the formula

$$a = 0{,}99^{\frac{1{,}6}{P_0 \cdot N \cdot V \cdot T_R \cdot T}} \qquad (8.3.3.3)$$

where T – planned pipeline service life (yeas).

8.3.3.4 Parameter *Z* shall be calculated from Table 8.3.3.4 based on *a* and λ parameters:

Table 8.3.3.4

Parameter *Z*

Z		*a*		
		0,9999	0,99995	0,99999
λ	1,0	9,21	9,90	11,51
	0,8	10,70	11,43	13,11
	0,6	13,46	14,25	16,06
	0,4	20,00	20,91	22,99
	0,2	47,98	49,31	52,27

8.3.3.5 Burial factor *K* shall be determined by the formula

$$K = \mathrm{Z} \cdot \lambda^2 \cdot \overline{h}, \qquad (8.3.3.5)$$

being a criterion of necessity for the subsea pipeline burial into the seabed soil on the route section in question:

where $K \leq 1$ burial of the pipeline is not required;

where $K > 1$ burial of the pipeline is required.

8.3.3.6 Maximum theoretical value of the pipeline burial into seabed soil on the route section in question Δh, in m, shall be determined by the formula

$$\Delta h = h_s \cdot (K - 1). \qquad (8.3.3.6)$$

8.3.3.7 Design value of the pipeline burial Δh_p, in m, is assigned based on the theoretical value with regard to correction factors considering the seabed soil type the pipeline to be buried, as well as the pipeline class, and shall be determined by the formula

$$\Delta h_p = \Delta h \cdot k_g \cdot k_0 \qquad (8.3.3.7)$$

where k_g – factor, considering seabed soil properties, shall be assigned according to Table 8.3.3.7-1;
k_0 – factor, considering the pipeline class, shall be assigned according to Table 8.3.3.7-2.

Table 8.3.3.7-1

Factors considering the seabed soil type

Soil type	Sands	Clay sands, clay loams	Clay
k_g	0,95	0,60	0,20

Table 8.3.3.7-2

Factors considering the pipeline class

	Pipeline class					
	L1	**L2**	**L3**	**G1**	**G2**	**G3**
k_0	1,0	1,5	1,5	1,0	1,5	1,5

8.3.3.8 Design value of the pipeline burial into the seabed soil may be also determined using numerical stochastic modeling of the gouging process approved by the Register. This method shall take into consideration the wind and current conditions during ice period, tide-induced fluctuations in the water level, seabed soil properties, static characteristics of morphometric ice formation properties obtained from sufficiently representative sampling.

8.4 MARINE OPERATIONS FOR PIPELINE LAYING

8.4.1 The requirements of the present Chapter are applicable to pipe-laying vessels and barges performing the pipeline laying on the seabed. The pipe-laying vessel shall be classed with the Register or other classification society recognized by the Register. The vessel shall be fitted with all necessary systems, arrangements and equipment for pipe-laying operations with regard to provision of the adequate safety. The basic requirements for the vessel shall be given in the specification and cover the following:

anchors, anchor chains, wire cables and anchor winches;
anchoring systems;
positioning and supervision equipment;
dynamic positioning equipment and reference system;
alarm systems;
seaworthiness of the vessel in the region;

cranes;

pipeline assembly equipment.

8.4.2 A maintenance manual for all systems and equipment to provide safety of operations shall be available on board the ship. Prior to operation the vessel and systems shall be surveyed by the Register.

8.4.3 For anchoring of the pipe-laying vessel it is necessary to have a layout chart of anchoring systems. The pipe-laying vessel shall operate in strict compliance with the layout chart of anchors providing the required forces on the tensioners. The anchor layout chart shall contain the following information:

expected pipeline route and laying corridor;

location of existing pipelines and installations;

prohibited anchoring zones; position of each anchor and cable touch down point;

vessel position for running each anchor and working position of the vessel when the anchor running is completed;

anchor handling with regard to weather limitations.

8.4.4 The minimum distances shall be specified between the anchors, anchor chains (ropes) and any existing fixed structures of subsea installations, pipelines or cables.

8.4.5 Requirements shall be specified for the positioning system and its accuracy for each type of the vessel and appropriate environmental conditions. The accuracy of the horizontal surface positioning systems shall be consistent with the requirements for the permissible deviations of the pipeline centerline in the process of laying. In order to monitor the positioning, the appropriate monitoring systems shall be developed, reference points shall be established.

8.4.6 Positioning systems shall have at least 100 per cent redundancy to avoid errors and faults in positioning. Documentation showing that the system has been checked within the specified limits of accuracy shall be prepared for familiarization to the surveyor to the Register prior to commencement of the pipeline laying.

8.4.7 A vessel using a dynamic positioning system for station keeping and location purposes shall meet the requirements of IMO MSC/Circ. 645 (Guidelines for Vessels with Dynamic Positioning Systems).

8.4.8 Prior to commencement of assembly operations, the dynamic positioning system shall be tested to ensure that all control devices operate within the prescribed limits of accuracy. The remote control system of propellers shall be tested in operation with the reference system, as well as in different failure modes.

Monitoring, alarm and back-up systems shall be tested in accordance with the established test procedures. The tests shall be witnessed by a surveyor to the Register.

8.5 METHODS OF PIPELINE LAYING ON SEABED

8.5.1 Subsea pipelines may be laid on seabed using different methods, the basic methods are as follows: seabed pull, free immersion, laying from the pipe-laying barge or vessel, lowering from ice, directional drilling. Other methods or their combination may be applied.

8.5.2 During selection of the laying method account shall be taken of environmental conditions, sea depth, seabed soil properties, duration of ice formation period, type of medium to be transported, possibility of tensile forces in the pipeline during laying, geometrical pipe parameters and pipeline material properties.

8.5.3 The subsea pipeline laying procedure shall be based on its movement to the route cross section and lowering to the seabed. Subsea pipeline laying flow diagrams shall indicate location of the installation site, methods of pipeline movement to the route cross section, application of tensile forces to the pipeline, pipeline buoyancy control and tie-in of the strings.

For pipeline laying one of the following process flow diagrams may be used:

.1 pipeline laying from a pipe-laying vessel with successive tie-in of the strings or unreeling from a reel;

.2 seabed pipeline pull of the pipeline with the preliminary full-length installation at the coastal assembly site;

.3 seabed pull of the pipeline with successive tie-in operations;

.4 pipeline lowering by free immersion with preliminary installation in the route cross section;

.5 pipeline lowering by free immersion with successive tie-in of the strings;

.6 near-bottom tows and lowering of the strings into the cross section;

.7 lowering with the use of inclined drilling.

Combination of different laying methods at subsea pipeline sections may be applied depending on the environmental conditions and route profile.

8.5.4 Pipeline laying by seabed pull.

8.5.4.1 The laying flow diagrams referred to in 8.5.3.2 and 8.5.3.3 shall be used for short subsea pipelines, selection of the particular laying flow diagram shall consider the pipeline length, route profile, weight and buoyancy, pulling facilities and their possible location (ashore and/or aboard).

8.5.4.2 When pulling of the pipeline (string) its bending radius at launchways shall not be less than the value stated in 8.2.5. When the less bending radius is assigned (curvature radius of launchways) the pipeline (string) strength shall be confirmed by the relevant calculation.

To decrease pulling force it is acceptable to use pontoons relieving the pipeline strings due to their lifting force and reducing the force of friction with the seabed.

8.5.4.3 When the pulling method is used, the following process documentation shall be prepared and submitted to the Register for review:

assembly and welding procedure of the pipeline strings at the coastal assembly site;

pulling flow diagram with indication of force application parameters and ways of rope anchoring;

procedure of the pipeline string tie-in;

pontoon pattern and calculation of pipeline (string) strength near pontoon location;

calculation of the pulling force and the pipeline (string) drag force;

structural diagram of lauchways.

8.5.5 Pipeline laying by towing afloat.

8.5.5.1 Application of laying flow diagrams referred to in 8.5.3.4 – 8.5.3.6 related to sea operations with the floating pipelines (strings) shall be limited by the allowable weather conditions along he pipeline route during laying and shall consider the sea depth, pipeline (string) length, weight and buoyancy, applicable towing devices and method of pipeline lowering onto the seabed.

8.5.5.2 Where pipeline is laid by towing afloat the following shall be developed and submitted to the Register for review:

assembly and welding procedure of the pipeline strings at the coastal assembly site;

pipeline (strings) launching and towing flow diagrams;

pontoon structural diagram and pontoon patterns (in case of negative buoyancy to the pipeline or string);

pipeline (string) additional ballasting flow diagram at excessive positive buoyancy;

water filling or pontoons release flow diagram;

pipeline (string) strength analysis when lowering onto the seabed;

tie-in of the pipeline strings.

8.5.5.3 At significant sea depth resulting in excess of allowable stresses during laying, method of free immersion of the pipeline (string) shall be supplemented by application of tensile forces or self-tensioning of the pipeline (string) when fastening its ends to the fixed shore piers. Pipeline strength analysis for determination of the required tensile force value shall be submitted to the Register for review.

For this purpose, in case of excessive positive buoyancy to the pipeline (string) it is allowed to use temporary (while laying) weight ballasting.

8.5.5.4 While making a design model for strength analysis of the submerged pipeline (string) section, non-zero limit conditions of the floating pipeline (string) sections shall be considered.

8.5.6 Steel pipeline laying from a pipelayer.

8.5.6.1 Subsea pipeline laying flow diagram referred to in 8.5.3.1 shall meet technical parameters of the pipelayer (including pipeline lowering methods and work limitations due to weather conditions), take into consideration sea depth and route configuration, geometrical parameters and properties of pipe material.

8.5.6.2 The pipeline strength during laying operations shall be provided as well as the absence of initial pipe damages after laying, such as residual plastic deformations and corrugations (local buckling) of the pipe wall and breakdown of ballast system or insulation shall be ensured. Tensioners shall be used (tensile forces shall be applied) at considerable depths of the pipeline laying.

8.5.6.3 When method of the pipeline laying from a pipelayer with successive tie-in of the strings is used the following process documentation shall be prepared and submitted to the Register:

laying flow diagram and design model;

assembly and welding procedure of the pipeline strings;

pipeline strength analysis during laying.

8.5.6.4 Laying of pipeline by J-method shall assume application of the horizontal force to the upper end of the pipeline, sufficient to ensure safe laying. The force shall be created by tensioners, anchoring system or dynamic positioning system of the pipelayer. Reliable positioning systems having at least double redundancy of the total pulling force shall be used. It is preferable to use the pipelayers (pipe-laying vessels) of semisubmersible type or stop laying in waves which may cause initial pipe damage.

8.5.6.5 Horizontal force applied to the upper end of the pipeline during its laying by J-method shall not be less than the value of F, in kN, determined on the basis of the following:

$$S_x^2 - S_x \cdot S_{hp} < 0{,}9 \cdot k_\sigma \cdot R_e^2 - S_{hp}^2 \qquad (8.5.6.5\text{-}1)$$

where S_{hp} – hoop stress, in MPa, obtained from the formula

$$S_{hp} = \frac{\rho_w \cdot g \cdot h \cdot D_{int}}{2 \cdot t_c} \cdot 10^{-6}; \qquad (8.5.6.5\text{-}2)$$

S_x – total longitudinal stress, in MPa, obtained from the formula

$$S_x = S_1 + S_2; \tag{8.5.6.5-3}$$

S_1 – longitudinal stress due to the horizontal force, in MPa, obtained from the formula

$$S_1 = \frac{F}{(D_{int} + t_c) \cdot t_c} \cdot 10^{-3}; \tag{8.5.6.5-4}$$

S_2 – longitudinal stress due to bending in the minimum pipeline curvature, in MPa, obtained from the formula

$$S_2 = \frac{M}{\pi (D_{int} + t_c)^2 \cdot t_c} \cdot 10^{-6}; \tag{8.5.6.5-5}$$

M – maximum bending moment in the pipeline, in kNm, obtained from the formula

$$M = \frac{E \pi D_{\mathrm{int}}^4 [1 - (1 - 2 t_c / D_{\mathrm{int}})^4]\, h}{64 L^2} \cdot \frac{(1 + m)(2 + m)}{6^m \cdot [1 + (2 + m)^2 / 6^{(1+m)} \cdot h^2 / L^2]^{3/2}} \cdot 10^{-9}; \tag{8.5.6.5-6}$$

L – free span length, in m, obtained from the formula

$$L = \sqrt{\frac{2 \cdot F \cdot h}{\gamma_p \cdot A}}; \tag{8.5.6.5-7}$$

m – dimensionless parameter, obtained from the formula

$$m = \frac{h \cdot \gamma_p \cdot A}{3 F}; \tag{8.5.6.5-8}$$

A – pipe cross section area, in m^2, obtained from the formula

$$A = \pi \cdot t_c \cdot (D_{\mathrm{int}} + t_c) \cdot 10^{-6} \tag{8.5.6.5-9}$$

where E – Young's Modulus of pipe material, in MPa;
g – gravity acceleration, in m/s^2;
h – sea depth at the laying area, m;
γ_p – specific weight of the pipe in water, kN/m^3;
ρ_w – sea water density, kg/m^3;
D_{int} – internal pipeline diameter, mm;
t_c – pipe wall thickness, mm;
k_σ – strength factor assigned according to Table 8.5.6.5.

Table 8.5.6.5

Strength factor due to the pipeline class

	Pipeline class					
	L1	**L2**	**L3**	**G1**	**G2**	**G3**
k_σ	1,0	0,95	0,9	1,0	0,95	0,9

8.5.6.6 During pipeline laying from a pipelayer by *S*-method, the pipeline strength analysis shall be submitted to the Register for review, the minimum force in the tensioner shall be assigned as the result of above analysis, having regard to stinger or slip geometry, provided the pipe strength criteria is met at each pipe section

$$S_x^2 - S_x \cdot S_{hp} + S_{hp}^2 < 0{,}9 \cdot k_\sigma \cdot R_e^2 \qquad (8.5.6.6)$$

where S_x – longitudinal stress in the pipe at the risk sections of the minimum curvature, in MPa;

S_{hp} – hoop stress in the pipe at the risk sections of the minimum curvature, in MPa;

k_σ – strength factor assigned according to Table 8.5.6.5.

8.5.6.7 During pipeline laying from a pipelayer with unreeling from a reel, the following process documentation shall be submitted to the Register in addition to one specified in 8.5.6.3:

reeling the pipeline on the reel (changeable drum);

pipeline tension control.

8.5.6.8 Reeling of the pipeline (strings) shall not result in the axial pipe strain exceeding 0,3 per cent. The pipe-laying vessel shall be fitted with a device to restore the shape of the pipe cross-section while unreeling of the pipeline.

8.6 SUBSEA PIPELINE TESTING BY PRESSURE

8.6.1 General.

8.6.1.1 Subsea pipeline pressure test shall be performed after the complete installation of pipeline system or its section (full backfilling, setting of valves, instrumentations and protectors, etc.), pipeline interior smart pigging, as well as submitting the required documentation to the Register (refer to 8.6.2).

8.6.1.2 Subsea pipeline pressure testing shall be conducted in two successive steps: strength test and leak test. Strength and leak tests shall be carried out by hydraulic method; it is allowed to perform leak test of gas pipelines by pneumatic method.

Pipeline hydraulic testing by water at air temperature bellow zero and/or at sea freezing temperature is allowed provided that the pipeline, valves and instrumentation are protected against freezing. Testing by pressure is only allowed when hotline communication is provided.

8.6.2 Documentation.

The pressure test shall be described in a test program or process documentation, which is subject to approval by Register prior to testing. The documentation shall contain the following:

.1 operation manuals, including:

pipeline filling with test medium;

method and rate of pressurization;

equipment/sections to be isolated during a holding period;

method and rate of pressure relief;

dewatering and removal of the test medium;

internal drying of pipeline, if necessary;

emergency and safety procedures and precautions;

.2 equipment and systems:

description of the pipeline section to be tested (dimensions, valves, pumps, etc.);

description of the test medium, including possible use of chemical additives;

specification of instrumentation and measuring devices (temperature, pressure, flow rate), including their location and connection;

description of calibration and marking of equipment;

distribution of temperature measuring devices along the length of the pipeline;

.3 calculations:

temperature and other environment influence on pressure, including estimation of the sensitivity of the test medium temperature due to variations of the seawater temperature;

"pressure-volume" assumption diagram.

8.6.3 Safety measures.

The test area shall be surrounded with warning signboards displayed in order to prevent unauthorized personnel from entering during the pressure test.

8.6.4 Strength test.

8.6.4 Pipeline strength testing by pressure shall be carried out for verification of the pipeline capability to operate at the working pressure with a specified safety margin. Minimum pressure during the hydrostatic strength test shall be equal.

for oil-products pipelines and gas pipelines – 1,25 times working pressure.

During hydrostatic strength testing the total stresses in the pipe shall not exceed 0,95 the pipe metal yield stress.

When testing the pipeline, the pressure buildup/drop rate shall not exceed 0,1 MPa/min, as soon as the pressure value reaches 0,9 of the test pressure, the rate of pressure buildup/drop shall be reduced up to 0,01 MPa/min.

Holding time of the pipeline at test pressure (without regard of pressure buildup and/or drop time, as well as holding time for equalization of temperature and pressure) shall be minimum 12 hours.

The pipeline is considered as having passed the strength test, if over the test period the pressure drop shall not exceed 1 per cent under continuous monitoring of pressure and temperature values or their discrete measurements every 30 min.

8.6.5 Leak test of the subsea pipeline shall be carried out after the strength testing by reducing the test pressure to the value exceeding 1,10 times working pressure. Duration of leak test shall be determined by the time required for inspection of the whole route or the test section, the test duration shall be minimum 12 hours without regard of pressure buildup and/or drop time, as well as holding time for equalization of temperature and pressure.

The pipeline is considered as having passed the leak test, if over the test period no leakage was detected, and change of pressure shall not exceed ± 0,2 per cent under continuous monitoring of pressure and temperature values or their discrete measurements every 30 min. Pressure variations in the pipeline up to ± 0,4 per cent shall be allowed due to fluctuations in the ambient temperature and sea level during the test period.

8.6.6 Test medium.

The test medium shall normally be filtered fresh water or filtered seawater, which, in order to avoid internal corrosion in the pipeline, may be chemically treated.

8.6.7 Pipeline flooding and pressurization.

8.6.7.1 During flooding of the test section, precautions shall be taken to limit the air inclusion to less than ± 0,2 per cent of the total filling volume.

8.6.7.2 For all methods of strength and leak tests, the pressure shall be measured using calibrated remote instruments or pressure gauges with a range equal to 1,25 the test pressure and the accuracy class not less than 1.

8.6.7.3 Air inclusion measurement in the test section shall be carried out during initial pressurization. This may be done by establishing a “pressure-volume" diagram based on the pressure and volume values measured during the pressurization.

8.6.8 Conservation of the test section.

In order to avoid internal corrosion, conservation of the test section shall be done after the pressure test. Inert gas or inhibited water may be used for the purpose.

8.6.9 Dewatering and drying.

Disposal of inhibited water requires permission from the national supervisory bodies, as it may be associated with the environmental hazards. Where drying is required, in order to prevent internal corrosion or hydrate formation, the detailed description of the procedure shall be submitted to the Register for approval.

9 MAINTENANCE AND REPAIR

9.1 MAINTENANCE

9.1.1 General.

9.1.1.1 Safety, efficiency and reliability of subsea pipeline operation shall be ensured with the regulated pipeline maintenance system, which shall be developed by a pipeline owner on the basis of the requirements of supervisory bodies, standards of the firms the above owner is associated with, and the Rules requirements.

9.1.1.2 The maintenance of subsea pipeline items shall include:

periodic inspections of the pipeline route;

instrumental studies of the pipeline route and the pipeline itself (pipeline fault detection);

periodical monitoring of the pipeline items and systems condition;

hydraulic tests of the pipeline;

repairs and repair-and-prevention works, including those after potential exposure to the accidental extreme loads.

9.1.1.3 Periodical monitoring of the pipeline items and systems condition shall be carried out with regard to:

cathodic protection/sacrificial anode system and ballasting;

isolation valves;

automation and alarm systems;

flanged joints;

risers and pipeline shore approaches.

9.1.1.4 The Register participation in periodical inspections and studies depends on the quality of maintaining the pipeline transport system by its owner and is a prerequisite to confirm the Register class for the subsea pipeline.

9.1.1.5 Maintenance regulations for the subsea pipeline items included in the Nomenclature of items of the Register technical supervision of subsea pipelines (refer to 1.6 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines) are subject to the Register approval.

9.1.1.6 Any changes of the maintenance regulations regarding the subsea pipeline items specified in 9.1.1.5, including any repairs, shall be agreed with the Register.

9.1.2 Examination and inspection program.

The owner of the subsea pipeline transport system establishes the procedure for inspections, studies and the pipeline maintenance regulations, which specify their frequency and extent, including the extent of initial, periodical, special inspections and studies and methods of their performance (in-line inspection, measurements of the external defects, etc.). It is recommended to harmonize the owner's system of pipeline inspections and studies with the Register system of periodical surveys (refer to Section 1.4 of the Rules and Section 4 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines).

The document containing the above provisions shall be submitted to the Register for review prior to the subsea pipeline commissioning.

9.1.3 Periodical examination and inspections.

9.1.3.1 The subsea pipeline transport system in operation shall be subject to periodical inspections and studies. Their performance is mandatory for the owner who shall notify the Register about the terms, methods and extent of the inspection. The inspections and studies shall be carried out by the Register-recognized organization involved in the in-water surveys and/or in-line inspections of subsea pipelines, in accordance with the requirements of Section 1.8 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines, and shall be supervised by the Surveyor to the Register.

9.1.3.2 The basic requirements for examinations and inspections and evaluation of their results are set forth in 9.1.4 and 9.1.5.

9.1.3.3 The terms of periodical inspections and studies, and the composition of parameters to be monitored during their performance shall be specified in accordance with 4.1.2 and 4.1.4 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines. In so doing, the actual technicall condition of the subsea pipeline and potential subsea pipeline damages after extreme natural or technogenic impacts (earthquakes, storms, registered effects of fishing tools, etc.) shall be considered.

9.1.4 Frequency of periodical inspections.

Setting the dates for conducting periodical inspections and studies, the following shall be considered:

predicted values of corrosive and erosive wear of pipes and potential deterioration of the mechanical properties of material during multiyear operation;

presence of active lithodynamic processes of the seabed soil;

presence of seabed soil drift/erosion, including in way of the pipeline shore crossing;

unsteadiness of the hydrometeorological parameters in a water area;

results of the previous inspections and surveys.

Periodical inspections and studies shall be conducted annually according to the Register-agreed regulations, following therewith the instructions of Section 4.1.4 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines.

In the event of extreme natural or technogenic impacts on the subsea pipeline, provision shall be made for extraordinary inspections and surveys, as well as for pertinent repairs, which extent is agreed with the Register.

9.1.5 Scope of periodical examinations and inspections.

9.1.5.1 In order to assess the technical condition and to provide the further safe operation of the subsea pipeline, as well as to plan the maintenance, the periodical inspections and studies shall provide for the following kinds of works:

general study of the pipeline route, including determination of its attitude position and the length of its sagging sections;

determination of the depth of the protective layer of the seabed soil (for subsea pipelines buried into the seabed soil);

control of corrosion-resistant coating condtion;

control of ballasting condition;

in-line inspection and external underwater examination to detect defects (fault detection);

control of valves condition;

control of cathodic protection/sacrificial anode system condition.

The composition of subsea pipeline parameters recorded in the above works shall meet the requirements of 4.1.2 and 4.1.3 of the Guidelines on Technical Supervision during Construction and Operation of Subsea Pipelines.

9.1.5.2 For periodical inspections of risers, the following items apply, in addition to those listed in 9.5.1.1:

inspection of clamps and bolts;

inspection of flanges condition;

assessment of marine fouling.

9.1.5.3 The assessment of the technical condition of subsea pipeline valves shall provide for:

checking of the remote drive operation;

inspection for flange and fastenings defects;

hydraulic testing;

inspection for the valve body defects;

inspection for shut-off and sealing components.

9.1.6 Records of periodical examination and inspection results.

9.1.6.1 The subsea pipeline owner shall submit to the Register review the results of periodical inspections and studies performed in terms and to the extent specified in 9.1.4 and 9.1.5.

9.1.6.2 The subsea pipeline owner shall record and take into account the completed results of periodical inspections and studies during the entire pipeline service life.

9.1.7 Modification.

Modification of the existing pipeline system shall be subject to approval by the Register. All documentation with calculations and explanations shall be submitted to the Register for reveiw prior to commencement of modification work and shall contain the following information:

description of modification;

assessment of the environmental influence in performance of modification;

list of equipment to be used during modification;

quality control and acceptance criteria.

9.2 REPAIR

9.2.1 Documentation.

9.2.1.1 Any repair to be carried out on the pipeline system under construction or in operation shall be described in the repair procedure, which shall be submitted to the Register for approval.

9.2.1.2 The description of the repair procedure shall include the following:

type of damages to be repaired;

welding technique to be used, welding procedure specification and preliminary assessment of its compliance with the technical requirements;

conditions of repair;

list of tools and equipment to be used during preparation, repair and post-repair work;

detailed description of the preparation of the repair area;

detailed description of the repair procedure;

detailed description of the post-repair activities including the non-destructive testing methods, pressure testing and acceptance criteria;

safety requirements.

9.2.2 Repair procedure.

9.2.2.1 Any repair shall be carried out only under the favorable environmental conditions.

9.2.2.2 The pipeline shall be repaired in compliance with the technical requirements for its construction and operational procedure. A necessity of performance of the pressure test following the repair shall be considered in each particular case.

No pressure test is required after the repair, in which no more than two repair welds are made, provided the extent of non-destructive testing is increased. In such case, in addition to visual examination, 100 per cent radiographic testing, ultrasonic or magnetic particle testing is required.

9.2.3 Repair of pipeline constructions.

9.2.3.1 Pipeline or pipes with defects or damages not within the specification requirements shall be repaired. The pipeline system shall be repaired prior to the pressure test.

Damages to be mandatory repaired include;

outside damage to pipes;

damage to the corrosion-resistant coating, weight coating or anodes of the corrosion protection system;

weld defects;

deformation and buckling of the pipeline;

damage to field joints;

corrosion damages;

damage to fastening devices; monitoring equipment; manholes/mudholes, etc.;

damage to anchor tie rods, supports and clamps.

9.2.3.2 Outside damage to the pipeline sections, such as dents, surface roughness and etc., may be removed by grinding. The minimum wall thickness shall be within the tolerance limits.

9.2.3.3 Weld repair, where unacceptable defects were revealed by non-destructive testing or visual examination, shall be carried out according to the procedure approved by the Register, including methods of the defect removal and welding of the defective area.

Repair shall be carried by the qualified personnel approved for works in compliance with the requirements of Section 5. After repair, the repeated inspection of welding quality shall be carried out by the methods of visual and measuring testing and non-destructive testing.

9.2.3.4 Corrosion areas may be repaired only after their examination for defects and assessment of their condition for compliance with the specification requirements.

Erosion section repairs shall be carried out by the same methods.

9.2.3.5 Buckling or other major deformation damage shall be repaired by the total cutting out of the damaged portion with subsequent replacement thereof.

9.2.3.6 A decision on carrying out a repair shall not be made before identification of the corrosion defects.

9.2.4 Repair of pipeline system without interruption of its operation.

9.2.4.1 Repairs on the pipeline resulting in a temporary interruption of its operation are allowed only subject to the special consideration by the Register. Any such repair shall result in a restored pipeline serviceability or serviceability acceptable for the remaining lifetime of the pipeline.

9.2.4.2 Damages to the pipeline resulting in a temporary interruption of its operation are as follows:

corrosion and erosion damages (external and internal);

cracks of various nature;

damage to the integrity of coatings; surface and geometric configuration of the pipe caused by external impacts;

unacceptable sagging of the pipeline;

significant damage to the weight coating (loss of the ballast cargoes).

9.2.4.3 Reductions of wall thickness detected during examination of the pipeline for defects shall be assessed by the methods recognized by the Register.

9.2.5 Repairs of the damaged areas shall be carried out by the partial replacement of the damaged pipeline section or by cutting out of the section with a spool piece. Other repair methods, such as installation of bolted clamps may be used upon the special consideration by the Register.

Repair of cracks by welding is permitted in cases when the cause is known or cracks are restricted to the small areas.

Repair by grinding for elimination of small surface defects is allowed, provided the minimum wall thickness remains within the specified limits.

9.2.6 Special safety measures shall be taken in case of welding or thermal cutting of the pipelines intended for conveying fire-hazardous and explosive substances.

10 SAFETY ASSESSMENT

10.1 SCOPE OF APPLICATION

10.1.1 For the purpose of this Section the objects of safety assessment are:
subsea field oil, condensate and gas pipelines;
subsea main oil, condensate, gas and oil product pipelines;
subsea distribution oil product and gas pipelines;
technological product pipelines containing hazardous substances.

10.1.2 This Section does not apply to hoses and temporary assembled pipelines used on the offshore gas and oil producing facilities.

10.1.3 Safety assessment shall cover the accidents caused by the following impacts and loads:
extreme hydrometeorological conditions;
seismic events;
hazardous geological phenomena on the seabed;
hazardous hydrological phenomena;
external impacts on pipelines;
internal and external corrosion;
processing equipment failures;
human errors during pipeline operation;
combinations of these events, phenomena and conditions;

10.1.4 The following hazards and their consequences shall be considered for the safety assessment:
errors in the pipeline design;
leakages in the pipeline;
damage and failures of the pipeline protection;
pipeline displacement relative to the location within the design project;
explosions;
fires;
combinations of these accidents;
other possible accidents.

10.1.5 Pipeline safety assessment shall be submitted to the Register:
for the personnel of the operating company and for population;

for the environment;

for objects and structures located in the areas of pipeline route and installation facilities.

10.2 TERMS, DEFINITIONS AND EXPLANATIONS

10.2.1 The main terms, definitions and explanations relating to general safety terminology are given in 1.2.

10.2.2 For the purpose of this Section the following additional definitions are used.

Accident means a hazardous technogenic accident that causes at an object, certain area or water area a threat to the human life and health and results in destruction of buildings, structures, equipment and transport means, in manufacturing or transport process irregularity, or environmental damage.

Accident on the pipeline means an accident on the pipeline route resulting in the emission or spillage under pressure of hazardous chemical or fire-hazardous substances and resulting in occurrence of technogenic emergency. Hereinafter, only an occurrence will be considered that might result in abnormal ingress of the conveyed hazardous substance (oil, oil products, condensate and gas) in the environment.

Risk analysis means a process of hazard identification and assessment of risk for individuals or groups of population, property or the environment. The risk analysis means use of all available information for hazard identification (detection) and assessment of risk of a certain event defined earlier (accident and emergencies involved) caused by these hazards.

Free-failure operation means capability of an item (object) to retain its serviceability during the specified period of time or until the completion of a certain work without forced breaks, e.g. for repairs.

Safety in emergency situations means condition of population protection, objects of national economy and environment against hazards in emergency situations.

Hazard identification means a process of hazard identification, recognition of its existence, as well as determination of hazard characteristics.

Accident initiating event means an event, occurrence or external condition creating on its own or in combination with other event, occurrences and external conditions a possibility of origination and evolvement of an accident.

Working order means a condition of an object, at which it complies with all the requirements of the normative and technical and/or design documentation.

F a i l u r e c r i t e r i o n o f s u b s e a p i p e l i n e means an indication or a combination of indications of the pipeline operable condition disturbance as specified in the normative and design documentation.

Quantitative risk indications are as follows:

i n d i v i d u a l r i s k means a frequency of individual injury as a result of hazardous effects (factors of danger) originating from emergency situations;

p o t e n t i a l l o s s o f l i f e (P L L) means an expected number of people injured to a specified degree as a result of possible accidents during a certain period of time;

p o t e n t i a l t e r r i t o r i a l r i s k means spatial and time frequency distribution of materialization of a hazardous effect of a certain level;

s o c i e t a l r i s k means a relation between the frequency of events and severity of their consequences expressed as data on frequency of hazardous events (F) at which there is a possibility to strike the number of people at a specified degree in excess of the number determined (N).

R e l i a b i l i t y means a property of an object to retain with the time within the specified limits the values of the parameters characterizing capability to fulfill the required functions within the specified operating conditions and application conditions, maintenance, storage and transportation.

H a z a r d means an objectively existing possibility (probability) of a negative effect on the society, individual, environment, which can result in a loss or damage impairing the condition and giving undesirable dynamics or parameters to their development.

H a z a r d o f t e c h n o g e n i c n a t u r e means a condition specific to the technical system, industrial or transport object that realizes in the form of harm to the environment when it occurs or in the form of the direct or indirect damage to an individual and environment during normal operation of the objects.

H a z a r d o u s s u b s t a n c e s means flammable, oxidizable, combustible, explosive, toxic, highly toxic substances and substances causing hazard to the environment.

F a i l u r e means malfunction in serviceability of the object.

R i s k a s s e s s m e n t means a process of an extent of risk identification of a considered hazard to the health of individual, property or environment. Risk assessment includes the analysis of frequency of the risk occurrence, analysis of consequences and combination of both.

D a m a g e means disturbance of the conveyed order of the object, with the serviceable condition being maintained.

N e g l i g i b l e   r i s k means a degree of risk, above which measures shall be taken for elemination thereof.

A c c e p t a b l e   r i s k means the risk, which level is allowable and substantiated based on economic and social considerations. The risk of an industrial object (subsea pipeline) operation is acceptable, provided its magnitude is so insignificant that the society is prepared to run the risk to benefit from the object operation.

S e r v i c e a b l e   c o n d i t i o n means a condition of an object, at which values of all the parameters that characterize a capability to fulfill the specified functions are in line with the normative and technical documentation.

R i s k means a combination of event probability and its consequences.

A c c i d e n t   s c e n a r i o means a complete and formalized description of the following events: accident initiation event, accident process and emergency situation, losses in accident, including specific quantitative characteristics of the accident events, their space-time parameters and causal relationship.

T e c h n o g e n i c   e m e r g e n c y   s i t u a t i o n means a condition where, as a result of occurrence of the technogenic emergency situation source at the object, in certain area or water area, normal conditions of life and activities of people are disturbed, their lives and health are threatened, damage is done to the national economy and environment.

10.3 BASIC PRINCIPLES

10.3.1 Subsea pipeline is an object of high risk (potentially hazardous object, hazardous production facility). Accidents on subsea pipelines are caused by an extremely wide spectrum of factors due to the environment and other objects.

10.3.2 Safety assessment is based on the assumption that design, calculations, manufacture, construction, operation and maintenance of the subsea pipelines shall comply with all the requirements of the Register normative documents and best applied technologies.

10.3.3 Safety shall be assessed at all stages of the subsea pipeline lifetime beginning from giving birth to an idea and concept of its creation.

10.3.4 For safety assessment a designer shall submit the following information:

environmental conditions;

functions, modes and specifics of the pipeline operation;

design impacts and loads;

drawings of the pipeline route, ballasting, underwater trenches, sacrificial anode arrangement, shore crossing structures, etc.;

hydraulic calculations, calculations of ballasting, material substantiation and pipeline wall thickness calculation, effectiveness of corrosion protection, weight of sacrificial anodes, etc.;

information on associated structures and supporting facilities;

list and description of basic arrangements aiming at reducing probability of accidents;

description of measures aimed to reduce consequences of an accident;

acceptable risk criteria for personnel, population and environment;

confirmation based on calculations that consequences of extreme environmental conditions and accident effects meet the adequate safety criteria.

10.3.5 Safety assessment is carried out in accordance with safety concepts based on the following principles or combinations thereof:

principle of unconditional priority of safety and health of people as compared to any other technical and economic benefits and advantages;

principle of risk acceptability, in compliance with which the low permissible and upper desirable risk levels, and within this range an acceptable risk level are established having regard to the socio-economic factors;

principle of the minimum hazard, in compliance with which the risk level is established as low as reasonably practicable;

principle of successive approximation to the absolute safety.

10.3.6 The ALARP ("as low as reasonably practicable") concept that materializes principle "to foresee and to prevent" is adopted in the Rules and in most of the international and national classification societies.

10.3.7 Risk analysis is an integral part of the safety control system, which aim is to prevent and reduce hazards to pipelines.

Risk analysis being the main link in provision of safety is based on the information collected and defines the measures on monitoring of the subsea pipeline safety.

10.3.8 Safety assessment of the subsea pipeline at all stages of design cycle shall be made for the purpose of selection of the most favorable design solution meeting the basic principles and requirements of safety. The result of this assessment shall confirm that correct decisions were made in design, which provide the required safety level and would not result later in a necessity of making significant modifications in design and construction due to non-compliance with the safety requirements.

10.3.9 Positive safety assessment of the subsea pipeline shall demonstrate an adequately low probability of human and financial losses, social and environmental risk. Safety assessment shall result in confirmation of the fact that the subsea pipeline complies with the criteria of sufficient (acceptable) safety.

10.4 BASIC REQUIREMENTS FOR RISK ANALYSIS

10.4.1 Risk analysis for the personnel, population and environment shall be mandatory for subsea pipelines.

Risk analysis may be carried out on its own or as a part of safety declaration of hazardous production facility. Its results shall be considered in safety assessment and expertise, shall be taken into account during technical and economic analysis, as well as during safety analysis and assessment of industrial objects and regions.

10.4.2 Risk analysis is a tool for detection and determination of hazards and risks. Risk analysis shall be aimed at justification of objective decisions on acceptable and achievable risk levels on the pipeline. This will enable to develop requirements and recommendations on the safety control.

10.4.3 The process of risk analysis shall contain:

planning and organization of work;

identification of hazards;

risk assessment;

elaboration of recommendations on reduction of risk levels (risk control).

Appropriate documentation shall be prepared for every stage of the risk analysis.

10.4.4 Planning and organization of work.

10.4.4.1 At the stage of work planning it is necessary:

to describe the necessity of risk analysis;

to choose the system to be analyzed and provide its review in detail;

to appoint the risk analysis performers;

to identify sources of information and provide availability of information on the system to be analyzed including decisions to assure its safety, as well as information on similar systems;

to assess limitations on initial data, financial resources affecting the scope and completeness of risk analysis;

to define the final target and tasks of the risk analysis;

to select and justify the risk analysis techniques;

to develop and substantiate the acceptable risk criteria.

10.4.4.2 For the purpose of selection and appointment of the risk analysis performers the necessary and possibility to involve experts, specialists from the design organizations and the Register representatives shall be studied.

10.4.4.3 At defining target and tasks of risk analysis all stages of the subsea pipeline life cycle (design, construction, commissioning, operation and possible modification and decommissioning) shall be reviewed.

10.4.4.4 While choosing risk analysis technique, it is necessary to take into account the set target and tasks, complexity of the processes under consideration, the availability and completeness of the initial data.

10.4.4.5 The acceptable risk criteria may be:

based on the normative and legal documentation;

established at the risk analysis planning stage with possible clarification in the course of stage completion or obtaining analysis results.

The main requirements for choosing the risk criterion are:

compliance with the best world practices and best applied technologies;

its validity and certainty.

10.4.5 Hazard identification.

10.4.5.1 The hazard identification task is detection, definition and maximum complete description of all possible hazards for the particular pipeline. Detection of the existing hazards is made on the basis of the information on the given object operational conditions, operation experience of the similar systems and expert data.

10.4.5.2 Hazards shall be identified systematically to ensure a full scope review and assessment of importance of all detected hazards. For the subsea pipelines the importance of hazards is evaluated by the presence of hazardous substances and their mixtures in the pipelines, potentiality of their uncontrolled leaks (outburst), possibility of ignition (explosion) source occurrence and external (technogenic and natural) impacts.

The importance of hazard identification stage lies in the fact that the hazards not detected at the identification stage will not be later considered and not taken into account.

10.4.5.3 For the purpose of identification, analysis and control of the hazards associated with the subsea pipelines, regular and thorough recording of accidents shall be maintained aiming at minimizing the consequences of such accidents. The most hazardous accidents are damages and faults caused by the pipeline leaks due to breaks and fractures in the base metal of pipes and welds, corrosion wormholes, joint leaks, pipe wall thinning down to impermissible values, etc.

10.4.5.4 Information on the subsea pipeline accidents shall contain description of conditions at the beginning of the accident and measures of fighting against the accident taken to eliminate its consequences; information on development of accidents; physical and statistical models, etc.

10.4.5.5 The preliminary analysis of hazard identification permits to determine what components of the pipeline system require more careful analysis and what components are of lesser interest in terms of safety.

10.4.5.6 As a result of hazard identification, a list of undesirable events causing an accident is compiled. Hazard identification is completed with determination of further activities, namely:

whether or not to stop the further analysis because of hazard insignificance;

whether to make more thorough risk analysis;

elaborate recommendations on reduction of the hazard level.

10.4.6 Risk assessment.

10.4.6.1 At the stage of the risk assessment the hazards detected in the course of identification shall be analyzed in terms of their compliance with the acceptable risk criteria. In so doing, the acceptable risk criteria and results may be shown qualitatively as a text (tables) or quantitatively by calculation of risk indications (refer to Appendix 2).

Where there are grounds to believe that hazards and their associated consequences of events are insignificant or their probability is very doubtful, the simplified hazard assessment may be assumed and decisions to exclude them from further consideration may be taken.

10.4.6.2 In selecting methods of risk analysis the priority shall be given to the qualitative engineering methods for risk analysis based on the approved procedures, special auxiliary materials (e.g., detailed methodological guides) and practical experience of the experts. Along with that, qualitative methods for risk assessment may be very useful, and sometimes they are the only acceptable ones, e.g. for comparison of different design decisions and/or for comparison of importance of hazards of different origin, as well as for confirmation of results neutrality.

10.4.6.3 Risk assessment includes the frequency analysis of initial and intermediate events, analysis of intensity of hazardous effects and consequences of the events revealed and analysis of the result uncertainties.

For the purpose of the event frequency analysis and assessment, the following approaches are normally used:

statistical data on accidents and reliability of the subsea pipeline similar in design and operating conditions to the type considered are used;

logic methods of event tree analysis or fault tree analysis applied;

expert appraisal with consideration of the opinions of specialists in the area of subsea pipelines is performed.

10.4.6.4 It is recommended to use expert appraisals and risk ranking methods in case of statistical data lack. Where such approach is used, the events under consideration are subdivided by a probability, severity of consequences into several groups (categories, ranks) with risk assessment by combination of probability and severity, e.g. with high, intermediate, low and insignificant risk degree. Normally the high risk degree is unacceptable, the intermediate degree requires a complex of measures to be taken for reduction of risk, the low degree is recognized to be acceptable and insignificant degree is neglected (refer to Appendix 2).

10.4.6.5 The analysis of the accident consequences includes assessment of impacts on people, environment and third party property. Analysis of consequences shall consider assessment of physical and chemical characteristics of hazardous effects (fires, explosions, emissions of toxic substances). For this purpose, the tested accident models and criteria of damage to affected objects including the subsea pipeline itself shall be applied.

10.4.6.6 Environmental risk assessment includes calculation of the following indicators:

values of maximum design emissions of transported harmful substances into environment, their intensity and duration at accidents on pipeline sections considering the pipeline route, technical characteristics and operating modes under normal conditions of operation and failures of the leak monitor system and emergency shutdown system of pipage;

annual frequency of excess of the specified leakages (it is recommended to make calculation for excess of 0,5 t, 50 t, 500 t and 5000 t of harmful substance);

annual average of leak and emission frequency at pipeline leakage due to any reasons;

average values of leakages;

average total leakages;

Calculation of maximum leakages for all modes shall be combined with hydraulic calculations of pipelines or shall be carried out separately using tested hydraulic models.

10.4.6.7 In risk assessment uncertainty and accuracy of the results shall be analyzed. The main causes of uncertainties are insufficient information on subsea pipeline operating conditions, reliability of the equipment and components used, and a human factor, as well as assumptions in the accident models.

Analysis of uncertainties is transmission of the initial parameter uncertainties and assumptions used in risk assessment into result uncertainties. The causes of uncertainty shall be identified and presented in the results.

10.4.7 Recommendations on risk reduction.

10.4.7.1 The final stage of the risk analysis is elaboration of recommendations on risk reduction (risk control).

Risk may be reduced due to measures either of technical or organizational nature, at that, during subsea pipeline operation the organizational arrangements may compensate a limitation of possible measures on reduction of hazard.

When measures on risk reduction are developed, account shall be taken of their effectiveness (influence on the level of safety) and possible limitations of the resources (both financial and material). Primarily, simple recommendations and measures that require less expenses shall be considered.

10.4.7.2 In all cases, the measures that reduce probability of an accident shall prevail over the measures that reduce accident consequences. Selection of measures to reduce a hazard has the following priorities:

.1 measures that reduce probability of accident occurrence including:

measures that reduce probability of fault occurrence;

measures that reduce probability of fault development into accident;

measures related to accident prevention and monitoring;

.2 measures that reduce severity of the accident consequences;

measures that provide change in the subsea pipeline conception or design, for example, selection of an appropriate pipe wall thickness, corrosion protection, rerouting etc;

measures dealing with organization, equipment and readiness of emergency services.

With equal possibility to implement the elaborated recommendations, priority shall be given to the accident prevention measures.

10.5 METHODS OF RISK ANALYSIS

10.5.1 Methods of risk analysis shall be selected, having regard to the purpose and tasks of analysis, adopted acceptable risk criteria, specific features of the subsea pipeline, nature of potential hazards.

Availability of the required and reliable information, resources allocated for the analysis, experience and qualification of the personnel performing the analysis, and other factors shall be considered.

10.5.2 Methods of risk analysis shall meet the following requirements:

to be scientifically and methodically grounded and consistent with its scope of application;

to give the results in such a form that allows understanding of the risk nature in the best possible way, develop and evaluate the most effective ways for the risk reduction;

to be repeatable and verified.

10.5.3 Generally one or several methods of risk analysis described below shall be used at the hazard identification stage:

checklist;

"What-if...?";
combination of checklist and "What-if" analysis;
hazard and serviceability analysis;
failure type and consequences analysis;
failure and event tree analysis;
appropriate equivalent methods.

Brief information on the above methods of risk analysis and conditions of their application is given in Appendix 3.

10.5.4 Recommendations for selection of the risk analysis methods at different stages of activities and subsea pipeline operation (design, routing, commissioning and decommissioning, operation, modification) are shown in Table 10.5.1.

The methods may be used individually or in combination. Qualitative methods may include quantitative risk criteria, based mainly on the expert appraisals, using such hazard ranking matrices, as "probability – severity of consequences" (refer to Appendix 2). Complete quantitative risk analysis may include all the methods listed.

Table 10.5.4

Method	**Stages of activity and functioning**				
	Design	**Arrangement and routing**	**Commissioning/ decommissioning**	**Operation**	**Modification**
"What-if analysis	+	0	++	++	+
Checklist method	+	0	+	++	+
Hazard and serviceability analysis	++	0	+	+	++
Failure type and consequences analysis	++	0	+	+	++
Failure and event tree analysis	++	0	+	+	++
Quantitative risk analysis	++	++	0	+	++

APPENDIX 1

RECOMMENDATIONS ON PROVISION OF RELIABILITY AND SAFETY OF SUBSEA PIPELINES ON SEABED SOIL

1 GENERAL

1.1 At the current level of technical development of subsea pipeline systems a probability of their damage during construction and operation due to various causes may not be excluded.

Referred to the main causes may be:

pipeline vibration and movement under the effect of hydrodynamic factors;

physical damages of subsea pipelines and their coatings by anchors, trawls, scrapers, vessel keels, ice formations, etc.;

external and internal corrosion (refer to Section 7);

improper ballasting of the pipeline (refer to Section 6);

weld defects of the pipeline base metal;

subsea pipeline buckling on the seabed soil (refer to Section 3);

pipeline sagging in the area of the seabed soil erosion;

inadequate monitoring of the subsea pipeline condition during construction and operation (refer to Section 9).

The types of subsea pipeline damages are breaks and cracks on the pipe base metal and on welds, through corrosion flaws, joint leakages, thinning of the pipe wall to unacceptable limits in places of abrasion against the seabed soil, high corrosive wear, dents, discontinuity of protective coatings, etc. The most severe consequences of the subsea pipeline damages are leakages and emergency spills of oil and oil products, condensate, gases and liquefied gases in case of seal failure.

1.1.1 Seabed soil may be washed out under the pipeline due to erosion processes caused by waves and currents, seabed shape changes, which may result in the pipeline sagging at long distances. An opposite phenomenon – covering of the pipelines laid on the seabed or in a trench without backfilling – may take place due to the same causes. Under the effect of sand (movable) soil erosion, the pipeline may go deeper into the seabed, self-deepening will occur, and its stability in the seabed soil will improve.

For the pipeline laying on the stiff and rocky seabed soil, underwater currents may cause the lateral movement of the pipeline and excessive bending stresses.

Flow of the pipeline laid on the seabed creates pressurized area behind the pipeline (in the direction of the flow). Shear stresses in this area as compared with adjacent areas are higher. Seabed soil erosion becomes more intensive in the pipeline laying area due to the differential pressure.

1.1.2 In the area of the seabed soil erosion below the pipeline, significant static stresses act on the pipeline due to the internal pressure, its own weight, drag force, hydrostatic pressure, and dynamic stresses due to alternating hydrodynamic forces that cause pipeline oscillations (vibration).

1.1.3 One of the causes of the seabed soil erosion in the pipeline laying area may be the action of the heavy water flows produced by a running vessel propeller in shallow water. The danger of such effect increases with reduction in depth under the vessel bottom and increase in vessel engine power.

1.1.4 A significant danger for subsea pipelines, especially in shallow water areas and in the areas with considerable fluctuations of the water level are physical damages to pipelines and their coatings by anchors, vessel keels, trawls, scrapers, ice formations and other objects.

1.1.5 Most dangerous for subsea pipelines in the regions, water areas of which are covered with ice during long periods of the year, are ice formations. They are characterized by large diversity, variability of properties and can exist in different forms, such as: level ice, ice with ice brash beneath, hummocks, stamukhas, icebergs. Different types of ice formations affect the pipeline structures during installation and operation in different way.

Ice formation may be subdivided in terms of fast and drifting level ice thickness into four categories, namely: light – up to 30 cm, medium – up to 100 cm, heavy – up to 200 cm and very heavy – over 200 cm. Then all prospective oil- and gas sea areas in Russia may be subdivided into five categories (refer to Table 1). It should be noted that ice fields of the same thickness in the seas of Russia are observed far from being everywhere.

Analysis of seasonal changes in traveltime and morphological parameters of ice cover in the water areas of oil and gas deposits in the Arctic and the Far East seas of Russia shows that there exists nothing similar in the world practice.

1.1.6 Special place among dynamic phenomena that take place in the sea ice cover is taken by large ice formations, which in interaction with the seabed, may result in its gouging by hummocks, stamukhas and less frequently by icebergs.

Probability of seabed gouging by ice formations, possibility of occurrence of concentrated additional loads on the subsea pipelines under the effect of stamukhas and icebergs settled on the seabed soil may have a determining influence on selection of pipeline routes, pipeline structure, burial depth into the seabed, seasonal periods for pipeline assembly, and, most importantly, on safety of construction and operation.

Table 1

Classification of prospective oil- and gas sea areas in Russia

Water area	The Caspian and the Baltic Seas, the Sea of Azov and the Black Sea basin, south-western shelf of Sakhalin Island	South-western part of the Barents Sea	South-eastern part of the Barents Sea, north-eastern shelf of Sakhalin Island	Coastal shallow water of the Kara Sea	Shelf of the Kara Sea
Sea depths, m	30 – 200	70 – 330	15 – 100	0-10	50 – 150
Ice conditions	Light	Light, medium	Medium, heavy	Very heavy	Very heavy
Average ice period duration, months	0 – 2	0 – 2	3 – 9	9 – 10	9 – 10

1.1.7 The phenomenon of the seabed erosion by melt water plunge pools is not ordinary process. Plunge pools are craters formed in shallow areas of the seabed. River and melt water flowing to the fast ice surface when snow is thawing penetrate through scours under the ice and flow very fast vertically down. Due to inertia forces and gravitation flows of this water are vortexed and wash out plunge pools in the seabed for several meters in depth.

Wash-out plunge pools themselves are not dangerous for the subsea pipeline but through stripping the pipeline they cause hazardous sagging of the pipeline and situate conditions for pipeline vulnerability due to hummock and stamukha backbones, and in case of open water, due to anchors and other foreign objects.

1.1.8 Big areas of the Arctic seas are located under frozen soil with different geocryological conditions. In case of pipelines conveying hydrocarbons at a temperature higher than temperatures of frozen soils, the latter start to melt and settle. It can result in pipeline stripping accompanied by occurrence of additional stresses in the pipe and other associated negative phenomena.

In order to prevent the above phenomena, a feasibility study shall precede the selection of the pipeline burying depth in the frozen soil, and additional protective measures shall be taken. Referred to such measures may be, for example, application of pipes with thick insulation (up to several centimeters thick) covered with a protective metal jacket. In case of short lengths of frozen soils, a possibility of the pipeline engineering protection may be considered that provides combined laying in one trench of the main piping and a tracer line of a small diameter that has a negative temperature.

1.1.9 In the regions of high seismic activity the soil sliding may occur especially in the inclined layers forming seabed deformation. Tsunami may also lead to a great seabed erosion and increase of the hydrostatic pressure on the pipeline. That is why it is necessary to perform analysis of geological structure of the foundation soil and geodynamic risks to select the pipeline route.

2 PROTECTION OF SUBSEA PIPELINES AGAINST HYDRODYNAMIC AND MECHANICAL EFFECTS

2.1 General

2.1.1 In order to protect the subsea pipelines against damages and to ensure fail-safe operation, use may be made of various methods, most of which shall be developed at the pre-conceptual and conceptual design stages. Referred to such methods may be: redundancy, restrictions on the minimum permissible distance between the parallel pipelines, laying in a trench with subsequent backfilling, seabed reinforcement in shallow waters, inshore and coast revetment in the transition section of the pipeline exposed to the greatest wave effects.

2.2 Redundancy

2.2.1 In order to assure reliability of the pipeline system the redundancy of the subsea pipeline by installation the booster pipeline parallel to the main pipeline may be allowed. The expediency of redundancy shall be supported by technical and economic feasibility study.

2.3 Distance between the parallel pipelines

2.3.1 The correct selection of a distance between the pipelines laid in parallel provides to a considerable extent safety of the subsea pipeline operation and uninterrupted transfer of transported media. The distance between the parallel pipelines shall be determined based on the conditions, under which an accident or catastrophe of one pipeline does not cause failure of the nearest parallel pipeline.

2.3.2 In general case, the distance between the parallel subsea pipelines shall be specified based on geological and hydrological conditions, methods of digging underwater trenches, if any, convenience of laying pipelines therein, safety of the pipeline in case of an accident. In all cases, the minimum distance between the parallel subsea pipelines shall be:

for gas pipelines buried in the seabed:

30 m at diameters to 1000 mm inclusive;

50 m at diameters over 1000 mm.

for gas pipelines laid on the seabed:

100 m at all diameters.

For oil- and oil product pipelines these distances may be the same as for gas pipelines; they may be reduced subject to adequate substantiation and the Register agreement.

2.4 Pipeline burying in a trench with subsequent backfilling

2.4.1 An efficient protection measure of the subsea pipeline against a destructive effect of waves, currents, storms, ice formations, physical damages by anchors, trawls, scrapers, etc. is burying of the pipeline in a trench with subsequent backfilling. This is a labor-consuming and expensive arrangement that requires performance of big volume of underwater earthwork.

2.4.2 A necessity of the pipeline burying and burying depth are dictated by hydrogeological conditions of the region, probability of the pipeline damage under external and internal effects, economic considerations.

In shallow water, especially where a probability of ice formation occurrence exists, pipeline burying is mandatory. Pipelines may be laid without burying and backfilling only at large depths; however, burying is also required in the coastal areas. Depths from 25 to 30 m and over may be considered to be fairly safe. Smaller depths are subject to special consideration. Most reliable will be a decision that is based on the most thorough investigation of the pipeline routing area for each particular case.

2.4.3 Burying of pipelines in the seabed shall be normally done by laying them in preliminarily dug or washed-out trenches. Rocky soils excavation using both crushing equipment or explosive methods may be allowed and such technology shall be approved by the technical supervisory bodies. The designed trench profile is normally assumed to be a trapezium. The requirements for trench construction and selection of main geometrical parameters (slope grade, trench width, distance between the pipe side and a communication cable, etc.), having regard to a free passage for a diver for the pipeline inspection after laying of the pipeline in the trench, seabed sediments, pipeline diameters and burying depth, shall be specified in the technical design.

2.4.4 In certain circumstances, pipelines may be buried after laying them on the seabed with the aid of pipe burying vessels or other special mechanisms. Pipe burying vessels shall be used where pipeline can be preliminarily laid following the natural contour of the seabed with acceptable bending radii and where there are no underwater rocks.

2.4.5 In case of ice cover in shallow water, a trench may be dug by a mechanism operating through openings in the ice.

2.4.6 The increase of the trench depth requires a substantial increase of power inputs. Therefore deep trenches shall be dug using several passages. Digging of more narrow trenches with strengthening of their walls by temporary baffles to prevent their fall may be an alternative.

2.4.7 Pipelines laid in trenches are backfilled with a soil to the design reference marks selected so as to protect the pipeline against the physical damages. Having been laid in the trench and tested before backfilling, the pipeline shall be inspected by a diver.

The following shall be determined in the course of the diver's inspection:

local soil erosion, pipeline sagging and displacements in relation to the design route, deviation from the design reference marks;

damages to external corrosion-resistant coatings;

breaks in solid weight coatings and correct arrangement of weights on the pipeline.

The defective places found are marked with buoys, and measures are taken to eliminate the defects.

2.4.8 Upon laying, subsea pipelines are backfilled to the design reference marks indicated in the design specification. The thickness of the seabed soil layer above the pipeline shall be not less than the design value or shall exceed it by not more than 20 cm.

The method of trench backfilling shall be chosen depending on the season of the year (whether it is winter or summer), trench depth, water depth, current velocity and earthwork to be done.

Where the local seabed soil in terms of its mechanical-and-physical properties is not suitable for backfilling, it shall be substituted by a specially brought soil. Sometimes, under special conditions where drifting sand currents occur, a sanding-up phenomenon can be used for trench backfilling (refer to 1.1.1), as well as for plunge pool self-filling (refer to 1.1.7), which allows considerable decreasing of the earthwork cost.

2.4.9 In exceptional cases, where the subsea pipeline burying is not economically feasible, and the length of the subsea pipeline is relatively small, bags filled with sand or stones, or mattresses of various types may be put above the pipeline or it is covered with polymer boards, reinforced concrete slabs, or combinations of the above methods are used.

2.4.10 For safety reasons the pipeline route is sometimes transferred to the area with more favorable conditions for pipeline construction and operation although it may result in increase of the pipeline length and cost.

2.4.11 In all cases, to determine the subsea pipeline routing and the required burying depth, comprehensive investigation of the suggested area for the pipeline installation shall be conducted. Such investigation shall include thorough studies of the seabed relief, depths, composition of the seabed soil, statistical data on winds, waves, currents, local changes in seabed shape, duration of ice coverage period, ice cover dynamics, especially of large ice formation. It is also necessary to know local specifics, such as presence of frozen soils under the seabed, probability of a thermal action of the product conveyed through the pipeline on the frozen soils, formation of plunge pools in the seabed soil, etc.

2.4.12 There does not exist a strict regulation of the pipeline burying depth, and it cannot basically exist. An issue of each pipeline protection and its safe operation shall be decided in each particular case individually based on investigation of the situation in the area of the pipeline route. The more thorough investigation is conducted, the more exactly the burying depth of the pipeline will be determined and the safer its operation will be.

Some generalized recommendations on burying depths of subsea pipelines in the sea bed soil are given in Table 2 below. Where no more reliable data are available, these recommendations may be used at earlier stages of the subsea pipeline design.

Table 2

Recommendations on selection of pipeline burying depth

Nos.	Prevailing external factor affecting the pipeline	Burial depth	Remarks
1	2	3	4
1	Large ice formations	The burial depth shall be determined by the maximum depth of gouging furrow plus 0,4 m	Recommendation does not allow for extreme cases
2	Seabed plunge pools	The burial depth shall be equal to the depth of plunge pool plus 1,0 m	
3	Frozen soils	Where pipelines for conveying hydrocarbons at a temperature higher than the surrounding frozen soils are laid, their burial depth shall be selected based on the calculation made using numerical methods that would allow to exclude melting and settling process capable to result in pipeline stripping	

1	2	3	4
4	Seabed soil erosion by currents, waves, flows from operating vessel's propellers	The burial depth shall be determined by the maximum possible height of the washed-out soils plus 1,0 m	
5	Currents and waves	Where rocks penetrate the seabed, the burial depth shall be the sum equal to the pipeline diameter plus 0,5 m	
6	Horizontal displacements	Where currents and waves shall be taken into account, the burial depth shall be selected so as to exclude the dangerous horizontal displacements	
7	Anchoring of marine engineering facilities	The burial depth in the area of possible anchoring of vessels or other engineering facilities shall be assumed equal to 2,5 m	Use of trawls, scrapers and other objects towed along the seabed shall be taken into consideration separately
8	Ecological water purity	Where pipelines are laid below the seabed of fresh water lakes and basins, their burying depth shall be based on the conditions that totally exclude loss of the water purity in the lakes and basins	
9	Problems with burying	Where it is impossible to provide the required burial depth, the pipeline route shall be transferred to the area with more favorable conditions for the pipeline construction and operation	
10	Large ice formations	In the areas with large ice formations, the burial depth may be assumed equal to zero (laying on the seabed) at possitive results of morthometric anylisis of ice formations that ptove the absence of gouging with specified probality. Generally this condition may be met at depths from 25 m till 30 m and over	Recommendation does not allow for extreme cases

APPENDIX 2

INDICES OF RISK ANALYSIS

1 GENERAL PROVISIONS AND CHARACTERISTICS

1.1 The risk concept is used for measurement of hazards that objectively associated with industrial activities and leading to accidents resulted in a loss of health and fatalities, harmful effects on the environment, destructions of material objects and losses of property and benefits.

1.2 The risk is measured by evaluation of the degree of risk as a set of risk indices and their values. The degree is found based on the results of the risk analysis which is a means to identify existing and potential hazards, to determine undesirable events with assessment of possible frequency and consequences of their occurrence, and to develop recommendations on reduction of degree of risk in case of acceptable level of risk is exceeded.

1.3 Depending on the purpose of risk analysis and available information the quantitative or qualitative indicators and methods of risk analysis are used.

In case of quantitative analysis, the results are obtained by calculation of numerical indicators of the degree of risk.

In case of qualitative analysis its results are presented by ranking and/or classification of accident frequency and consequences of accidents using the predetermined appraisals and/or opinions of qualified experts.

Results of risk analysis are presented in the form of the text analysis, quantitative indicators, tables, diagrams, charts and other means.

1.4 The degree of risk of accidents with an engineering system is determined based on the analysis of all indices of risk found in analysis of undesirable events capable cause accidents under certain circumstances (e.g., leakage of pipeline and equipment, failure of warning, alarm and monitoring systems, errors of attending personnel, unfavorable weather conditions, external mechanical impacts, etc.).

Based on the principal cause of risk occurrence, risks are subdivided as follows:

natural risks mean risks associated with the natural disaster, such as earthquakes, floodings, storms, tornados, etc.;

engineering risks mean risks associated with the hazards caused by technical objects;

Based on the objects exposed to danger, risks are subdivided as follows:

humanitarian (social) risks mean risks associated with danger to life, health or living environment;

property (financial) risks mean risks associated with the hazard of inventory loss, malfunction of the subsea pipeline, reduction of results of financial and economic activities.

environmental risks mean risks associated with the adverse environmental impact;

2 POTENTIAL TERRITORIAL RISK

2.1 Potential territorial risk means a spatial distribution of frequency of consequences of a certain level or hazardous effects of a certain type leading to these consequences over a certain period of time. For example, the potential risk of fatality on a certain territory is determined by the frequency of at least one lethal of an accident on the considered area (shock wave, thermal effect of fire, chemical contamination, etc.).

Potential risk characterizes the hazardous object and territory regardless of presence of people in the area of hazardous exposures.

2.2 In practice the distribution of potential risk is defined as a set of frequency values of a certain level hazard occurrence on the territories for all or single sources (objects and accidents on them) and all or some damage effects of accidents.

2.3 Potential risk is an intermediate measure of a hazard used for assessment of individual and societal risks.

Individual risk is calculated by a given territorial risk using distribution of frequency of presence of an individual in the particular areas of the territory.

Societal risk is defined by a given territorial risk using distribution of number, places and time of staying of people in the area under consideration.

3 INDIVIDUAL RISK

3.1 Individual risk means a probability (frequency) of individual injury P of a certain degree caused by action of type A hazard factors over a certain period of time.

In case of technical hazards, individual risk is basically determined by a potential risk and probability of presence of an individual in the area of possible action of accident hazardous factors during the time sufficient for lethal effect.

Individual risk is determined in many respects by the taken safety measures (e.g., timely public alert, application of protection means, evacuation etc.), skills of people to act in hazardous situations and their protectability.

3.2 Individual risk is measured by a probability of a certain degree of consequences (fatality, injuries, disability) over a certain period of time (usually over a year).

3.3 At various effects (e.g., blast injury, thermal effect of fire, chemical poisoning with harmful substances or combustion products, etc.), the total individual risk may be determined as a sum of risks for separate effects provided their independence.

3.4 In practice, the individual risk analysis is made for groups of people characterized by approximately the same time of staying in different hazardous zones and use similar protection means rather than for an individual. Individual risk of attending personnel, personnel of an object in general and population of surrounding areas is normally considered.

4 SOCIETAL RISK

4.1 Societal risk characterizes the scale of possible accidents and catastrophes and is determined as a function called *FN*-curve. Depending on the purpose of the analysis, *N* may mean either the total number of people affected or the number of fatalities or another indicator of severity of consequences. *F* means the frequency of events with a severity of consequences exceeding the given value *N*. The example of plotting *FN*-curves is given in the Rules for the Classification and Equipment of MODU/FOP.

4.2 The criterion of the acceptable degree of risk is determined in such case not by damage from a single event but a curve plotted for all possible scenarios and consequences of accidents.

A general approach for the analysis is use of two curves – for the calculated societal risk and acceptable societal risk. Where the curve of calculated risk is above the curve of the acceptable risk at least on one line portion (the greater number of injured at the same frequency or higher frequency for the same consequences) then the relevant design decision and/or taken safety measures shall be considered unacceptable and they shall be subject to review. The area between these curves defines the intermediate degree of risk and the issue regarding how to reduce it shall be decided based on the feasibility study and on agreement with the Register.

4.3 Assumed as variable *N* may be proprietary or environmental damage, then, corresponding to these values *FN*-curves that will serve as a measure of insurance or environmental damage can be plotted.

5 POTENTIAL LOSS OF LIFE (PLL)

5.1 Potential loss of life (PLL) is an integral measure of a hazard and determines the expected number of injured resulted from an accident on the territory of an object over a certain period of time (e.g., over a year or over the whole period of object operation).

5.2 The individual and potential loss of life may be transferred into economic and financial categories. For this purpose, various approaches to define "the cost of life" are used in practice:

to develop safety measures – as a value of extra costs for object construction and operation necessary to reduce potential loss of life per unit;

to evaluate damage – as a value of costs and compensations in case of fatality.

The concept content definition and relevant values shall be defined to establish acceptable risks criteria.

6 ENVIRONMENTAL RISK

6.1 Environmental risk means damage to the environment after the accidents on hazardous objects.

6.2 The following indicators may be used to assess environmental safety:

the value of the maximum calculated volumes, intensity and duration of emissions of transported harmful substances into the environment at accidents on pipeline sections;

annual exceedance frequencies of the specified leakages (*FN* curves);

annual average frequency of leakages and emissions at pipeline leakage by any reason;

average volume and average total volume of leakages.

6.3 The following indicators may be used to determine environmental risk in value terms (e.g., for insurance purposes):

statistically expected compulsory payments and obligatory indemnifications for harmful substances emission into the environment;

statistically expected costs for remedial action.

The above indicators shall be calculated in direct value terms and as a risk of damage (the value determined by the product of the accident frequency by a damage).

APPENDIX 3

METHODS OF RISK ANALYSIS

The principal methods recommended for application in risk analysis are given in this Appendix. The representative scenarios of potential accidents at subsea pipelines are also provided as failure trees and a tree of events, which may develop after the occurence of an emergency event. For reference, the information on the accident rate of subsea pipelines is added.

1 Checklist and ”What-if” methods or their combination refer to a group of qualitative hazard assessment procedures based on studying compliance of the operating conditions of the object (the subsea pipeline) with the safety requirements in force.

1.1 The checklist is a method for identification of compliance of a designed or operated object with the existing standards. This method is used at any stage of the object's life cycle and allows identification of the existing hazards.

1.2 The checklist method is drawn up, where necessary, for specific situations and is used, for example, for assessment of correctness of marine operations, solution of the problems that require careful attention.

1.3 The result of the checklist method is a list of questions and answers regarding compliance of the subsea pipeline with safety requirements. An example of drawing up of the checklist for the analysis of accident situation is given in the Rules for the Classification and Equipment of MODU/FOP.

1.4 The checklist method differs from the “What-if” method in more complete presentation of the initial data and results of safety violation consequences.

1.5 The «What-if» method uses the questions beginning with “What-if” and considers the development of a situation after these words. The compilers of an analysis shall be very cautious and adequately realistic in order to avoid improbable scenarios of the event development in emergency situations.

1.6 The «What-if» method may be used during design, modernization or operation of the subsea pipeline. It results in a list of hazard zones that are potential for accidents and the methods supposed for accident avoidance and prevention.

1.7 The above methods are fairly simple if preliminary provided with auxiliary forms, unified forms for analysis and presentation of the results, relatively inexpensive and most effective in studying well-known objects with a minor risk of major accidents.

2. Failure Mode and Effect Analysis (FMEA) is used for qualitative safety assessment of engineering systems and is applied for determination of failures causing or contributing to occurrence of accidents. The specific feature of this method is consideration of possible failures of each engineering system part (the pipeline component) or an individual component (type and cause of failure) and failure effects during the subsea pipeline operation.

2.1 At the design stage of the subsea pipeline FMEA may be used to determine the necessity of additional safety measures or their reduction. In modernization of the subsea pipeline, FMEA permits to determine their influence on the existing structures and equipment. The method may be applied during operation of the pipeline for identification of single failures likely to result in severe consequences.

2.2 Subjectivity of FMEA method requires involvement of several experts in its application, competent in issues of the pipeline transport processes and the equipment used. The method of analysis of failure types and consequences may be used together with other methods of hazard identification, e.g., HAZOP.

2.3 Failure Mode, Effects and Critical Analysis (FMECA) is similar to FMEA but, different from that method, it allows to add results of analysis due to the fact that each type of failure is ranked with regard to two criticality components – combinations of probability (or frequency) and severity of failure consequences. Record of criticality parameters allows to substantiate the priority of safety measures. The concept of criticality is close to the risk concept and therefore may be used in quantitative analysis of accident risk.

2.4 FMECA results are presented in the form of standardized tables with a full list of equipment and components, types and causes of possible failures, frequency, consequences, criticality, failure detection means (alarms, monitoring devices, etc.) and recommendations on hazard mitigation.

2.5 The following criteria may be considered in terms of severity of consequences:

catastrophic – results in fatalities, causes long-lasting and large-scale damage to the environment, significant damage to material objects;

critical (non-critical) failure – threatens (does not threaten) human life, environment, material objects;

failure with negligible consequences – a failure which refers, in terms of its consequences, to none of the above three categories.

2.6 Recommended indicators (indices) of the level and criticality criteria in terms of probability and severity of consequences of failure (event) are shown below in the <u>“Probability – severity of consequences” matrix</u>.

Table 1

Expected frequency of occurrence (1/year)		Severity of consequences			Failure with negligible consequences
		Catastrophic failure	Critical failure	Non-critical failure	
Frequent failure	> 1	A	A	A	C
Probable failure	$1 – 10^{-2}$	A	A	B	C
Possible failure	$10^{-2} – 10^{-4}$	A	B	B	C
Infrequent failure	$10^{-4} – 10^{-6}$	A	B	C	D
Practically unlikely failure	$<10^{-6}$	B	C	C	D

In practice, four groups of affected objects to which damage may be caused by an accident, may be selected for the analysis, namely: attending personnel, population, environment, material objects. In the case under consideration, rank A corresponds to the highest (unacceptable) risk degree that requires immediate safety measures to be taken. Ranks B and C correspond to the intermediate risk degrees, and rank D to the safest conditions.

Depending on the hazard rank:

A – thorough detailed risk analysis is mandatory, special safety measures are required for reduction of risk;

B – detailed risk analysis is desirable, safety measures are required;

C – risk analysis and safety measures are recommended;

D – no risk analysis and safety measures are required.

In risk analysis, contributions of risks of the subsea pipeline component failures to the joint risk of an accident shall be assessed and these data shall be used for the development of recommendations.

2.7 FMEA and FMECA methods may be used for analyzing designs or during modernization of the subsea pipelines. The analysis with application of such methods is normally made by a team of 3 to 7 people with mandatory involvement of the independent experts.

3 Hazard and Operability Study (HAZOP) investigates the effect of deviations of technical parameters (pressure, temperature, etc.) from normal operating conditions from the viewpoint of hazard occurrence. HAZOP method may be used in design, modernization and operation of the subsea pipelines. In terms of complexity and detailedness of the results, the HAZOP method is consistent with the FMEA and FMECA methods.

3.1 In the course of analysis possible deviations in operation and their causes are identified, and a list of measures and recommended alterations, proposals or actions to improve safety and/or operability aimed to detect and prevent the deviations is compiled for each subsea pipeline and its equipment.

3.2 A standard set of key words that helps to reveal systematically all possible deviations (such as "no", "more", "less", "as well as", "another", "other than", "opposite to", etc.) are used to characterize the deviations. The concrete combinations of the words with technical parameters are determined by specifics of the media transported through the pipelines and appropriate conditions. The approximate combinations of key words are as follows:

"NO" – no direct supply of the transported medium when it shall take place according to the process;

"MORE" ("LESS") – increase (reduction) in values of operational variables in comparison with the specified values (pressure, throughput, temperature, etc.);

"AS WELL AS" – new components included (air, water, impurities);

"ANOTHER" – condition different from normal operation (start-up, stop, etc.);

"OTHER THAN" – total change of the process, contingency, destruction, depressurization, etc.;

"OPPOSITE TO" – logic opposition to intention, backflow of the transported medium.

3.3 The HAZOP method results are presented on special flow sheets (tables). The degree of hazard may be determined quantitatively by assessment of probability and severity of consequences of the accident under consideration, using criticality criteria similar to FMECA method.

In addition to identification of hazards and their ranking, the HAZOP method similar to FMECA permits to clear up uncertainties and inaccuracies in safety instructions and to improve them. Efficiency and effectiveness of this method depend to a considerable extent on qualification of experts. The disadvantages of HAZOP and FMECA methods can be explained by the absence of possibility to analyze combinations and cause-effect relations of events causing an accident.

4 Logic and graphic methods of "failure and event trees" analysis

4.1 "Failure and event trees" analysis methods are logic and graphic methods used to reveal cause-effect relations between the events.

4.2 Fault tree analysis (FTA) permits to detect combinations and sequence of equipment and component failures, personnel errors and external (technogenic, natural) effects causing the main event, i.e. an accident. The FTA method is used for analysis of likely causes of accident occurrence and calculation of frequency based on the knowledge of initial event frequencies. Examples of construction and application of the fault tree for analysis of accidents is given in the Rules for the Classification and Equipment of MODU/FOP.

4.3 The Event Tree Analysis (ETA) is an algorithm of plotting sequence of events resulted from some main event (accident), which under certain conditions (occurrence or absence of other events, actions and/or circumstances) may lead to an accident situation.

For analysis of accident development, the event tree is materialized in the form of risk distribution diagram. The plotting of the event tree branches starts from events suggested by information on accidents in the past, as well as compiling a priority list of hazards detected by qualitative methods of analysis.

The frequency of each stage of development of an accident is found by multiplying the previous stage by probability of occurrence or absence of the event or condition expected at this stage. For instance, accidents with leakage of subsea oil or gas pipeline (occurence of ignition source) can develop with and without ignition depending on the particular conditions. In turn, the ignition under certain circumstances (drop of pressure in an accident section) can develop following the jet fire or focal fire scenario (flood fire).

The tree is constructed until the occurence of events being subject of risk analysis (injury of people, emission of harmful substances into the environment, etc.). Particular probabilities of these events occurred during materialization of various scenarios are integrated to get consolidated risk indicators for the main analyzed event.

4.4 Fault and event tree techniques allow to review the events and conditions of various nature in combination – initial failures of processing and monitoring equipment, operation of safety systems, actions of operators, external effects, etc.

4.5 Fault and event tree techniques are labor consuming and are shall be used for analysis of designs or revamping of sophisticated engineering systems. Specific objects subject to the quantitative risk analysis (the pipeline system in general, its part or production assembly, certain types and scenarios of accidents, etc.) shall be determined at previous stages of risk analysis.

5 Quantitative methods of risk analysis are characterized by calculation of risk indices given in Appendix 2 and can include one or several of the above methods or use their results.

5.1 The efficiency of the quantitative risk analysis becomes mainly apparent:

at object design stage;

in safety assessment of the objects which have equipment of the same type;

where complex evaluation of accident impact on people, environment and material objects is necessary;

in development of a list of priority measures on protection of the hazardous object.

5.2 Performance of the quantitative analysis requires high qualification of personnel, big volume of information on failure rate of equipment, consideration of specific features of the locality, weather conditions, time of staying people in the risk area of the hazardous object territory, the conditions of population staying in the neighbouring regions and other factors.

Mathematical models and calculation procedures for the assessment of physical-chemical and other events accompanying the accident shall be used at intermediate stages of the analysis.

5.3 Limitations of the quantitative risk analysis methods are as follows: high labour intensity, cost and duration of preparation and analytical works, as well as possibility of obtaining results characterizing significant statistical uncertainty, which doesn't allow to justify practical safety measures.

6 Representative scenarios of potential accidents at subsea pipelines.

The example of the representative failure tree for the subsea pipeline is shown in Fig. 1.

The representative scenarios of potential accidents at subsea pipelines as the trees of failures resulting in breaking the pipeline integrity at external and internal corrosive wear are shown in Figs. 2 and 3.

The example of the tree of events, which may develop after the occurence of an emergency event (breaking the pipeline integrity due to corrosive wear) is shown in Fig. 4.

7 Information on the accident rate of the subsea pipelines on the basis of foreign experience of subsea pipelines operation.

At present the systems of subsea pipelines in terms of their number, length and operational experience have been established in the North Sea and the Gulf of Mexico. The data on the accident rate of subsea pipelines for those systems are available in the following sources:

data of the Health and Safety Executive (UK) – on the North Sea pipelines;

data of the Office of Pipeline Safety of the USA Department of Transpotation (USA) – on the Gulf of Mexico pipelines.

The characteristics below feature the accident rate of subsea pipelines.

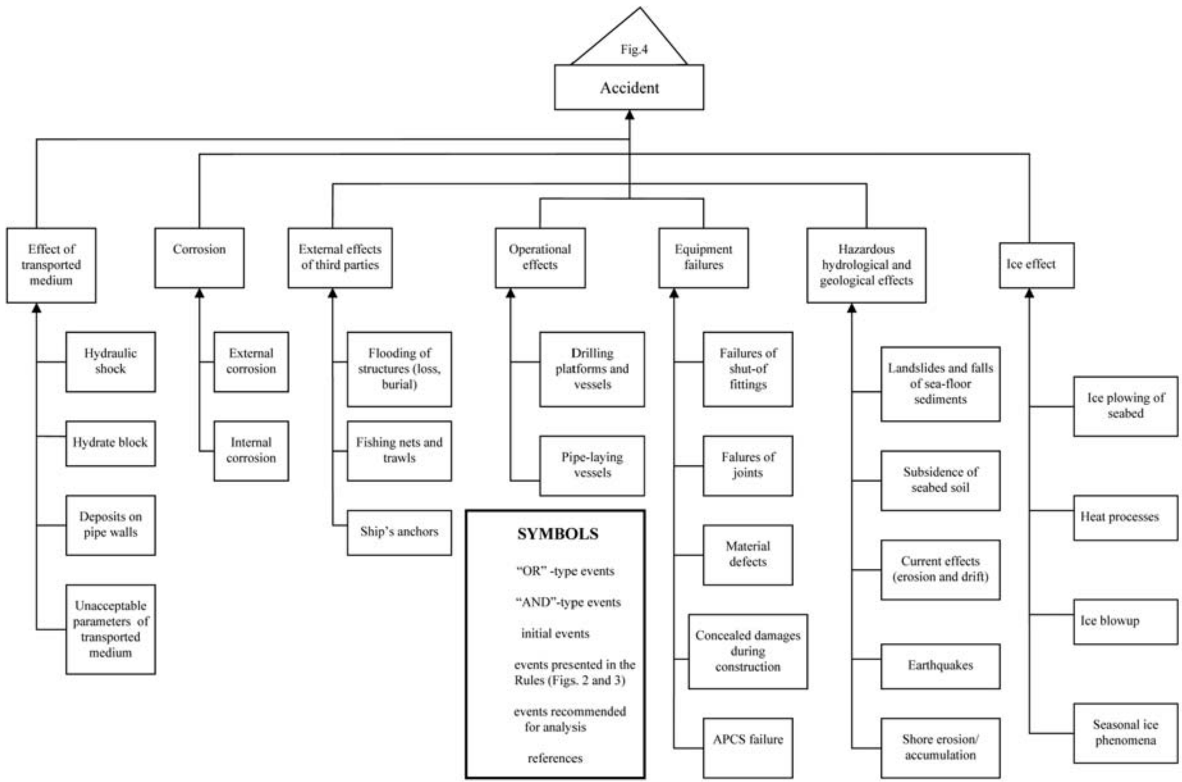


Fig. 1
Failure tree for subsea pipeline accidents (break of pipe integrity)

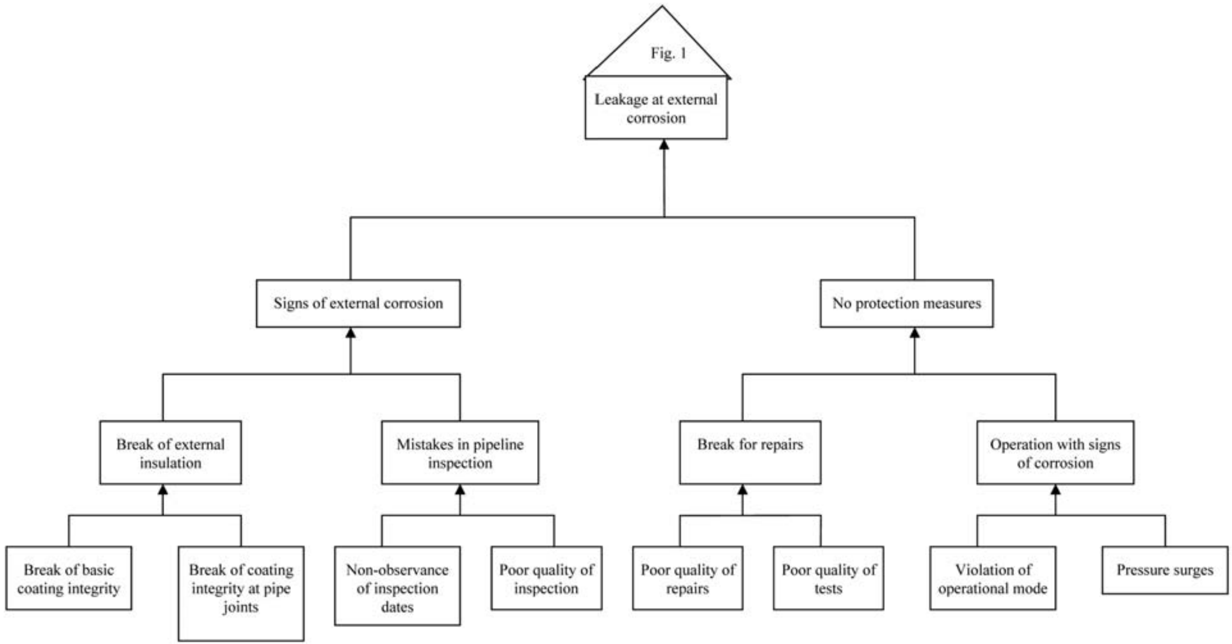


Fig. 2
Failure tree for an accident associated with external corrosion of a subsea pipeline

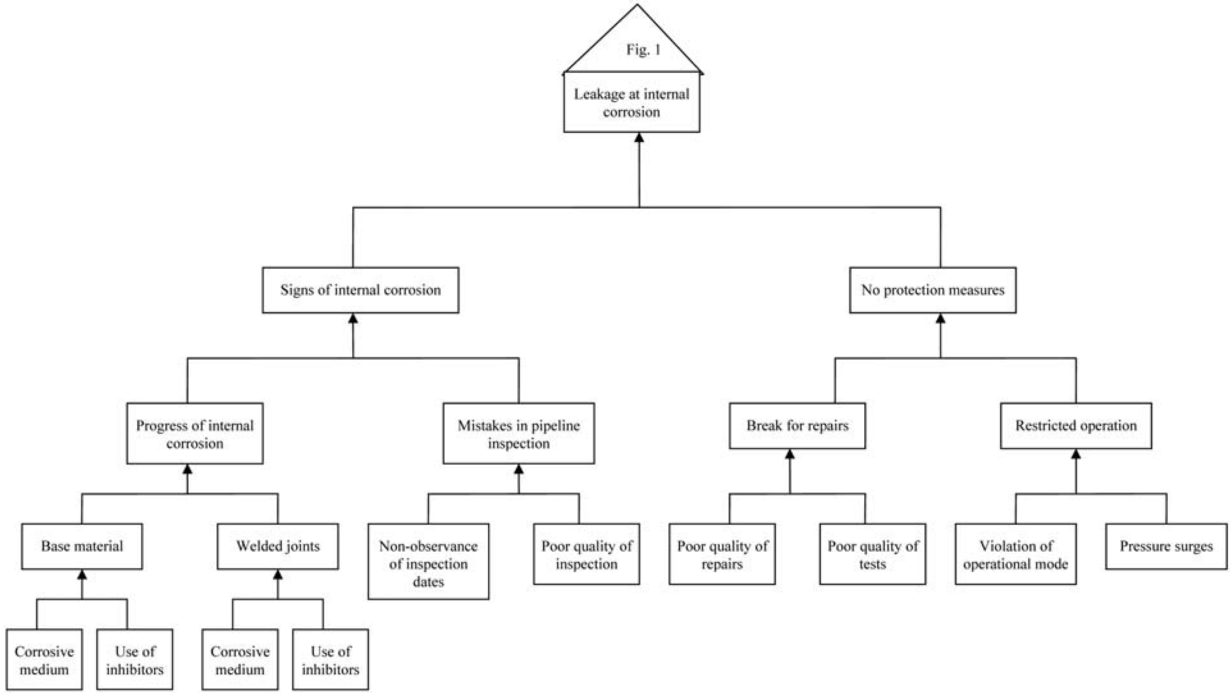


Fig. 3
Failure tree for an accident associated with internal corrosion of a subsea pipeline

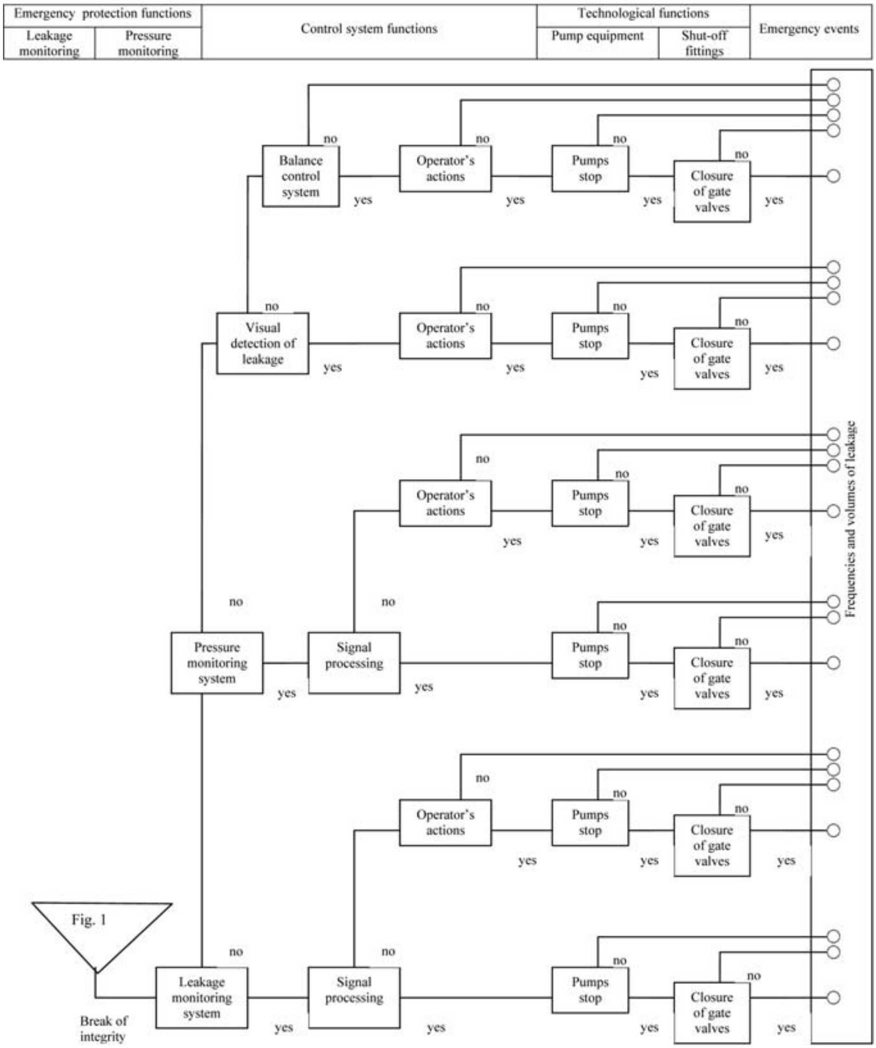


Fig. 4
Event tree for subsea pipeline accidents (break of pipe integrity)

7.1 The North Sea pipelines

1069 steel subsea pipelines of 40 inches in diameter with the total operational experience over 300000 km × year have been in operation in the North Sea by the end of 2000:

Table 2

Pipeline diameter, inches		Number of pipelines by the end of 2000	Total length of pipelines by the end of 2000	Lifelength for 1971 to 2000, km × year
All steel pipelines		1069	22848,0	307246,0
By diameter, inches	up to 9	552	5034,0	52973,0
	10 to 16	266	3889,0	47536,0
	18 to 24	126	4352,0	58843,0
	26 to 40	84	8441,0	147571,0
	no data	41	1131,0	322

The following characteristics feature the accident rate of the given system of subsea pipelines during the entire period of its operation:

Table 3

Pipeline diameter, inches		**Lifelength, km × year**	**Number of accidents**		**Design frequency, 10^{-4} (km × year)$^{-1}$**	
			accidents followed by repairs	**accidents with leakages**	**accidents followed by repairs**	**accidents with leakages**
up to 9		45679,0	11	7	2,41	1,53
≥ 10		243843,0	15	4	0,62	0,16
of them:	10 to 16	44286,0	11	1	2,48	0,23
	18 to 24	56728,0	1	1	0,18	0,18
	25 to 40	146052,0	4	2	0,27	0,27

7.2 The Gulf of Mexico pipelines

The following accident rate on the accidents resulting in leakages into the environment was the case in the Gulf of Mexico during a period of 1985 to 1999 with the operational experience of 184000 km × year:

Table 4

Pipeline diameters and leakage volumes		Lifelength, km × year	Number of leakages for period	Design frequency, 10^{-4} (km × year)$^{-1}$
< 10 inches in diameter		105390	7	0,66
by leakage volumes (barrels)	50 to 100		2	0,19
	100 to 1000		2	0,19
	1000 to 10000		2	0,19
	> 10000		1	0,09
≥ 10 inches		78879	8	1.01
by leakage volumes (barrels)	50 to 100		1	0,13
	100 to 1000		2	0,25
by leakage volumes (barrels)	1000 to 10000	78879	4	0,51
	> 10000		1	0,13

Based on the given data, the following levels of risk management according to the ALARP principle may be recommended in specifying the risk criteria of leakage occurrence (environmental risk) for the subsea pipelines being designed:

inadmissible risk level: $1{,}0 \times 10^{-4}$ (km × year)$^{-1}$;

negligible risk level: $0{,}5 \times 10^{-5}$ (km × year)$^{-1}$;

risk level to be analysed: from $0{,}5 \times 10^{-5}$ to $1{,}0 \times 10^{-4}$ (km × year)$^{-1}$.

The establisment and observance of such levels of risk management shall allow ensuring the safety of the new subsea pipelines being constructed at the level superior to that in world practice.

In establishing the criteria and during the risk analysis it is necessary to consider the details of subsea pipeline route sections which affect the degree of a hazard of accident occurrence:

sections within the safety zones of offshore gas and oil producing facilities and wells with underwater wellhead;

sections in areas with shipping, fishing and other activities in the water area;

sections in areas with hazardous geological phenomena;

sections in areas with deformation of the seabed and coastlines;

sections in areas with hazardous ice and cryopedological effects;

sections, which threaten with pollution of specially guarded and sensitive territories in case of leakages.

SPECIAL TEST PROCEDURES

1 DETERMINATION OF CRITICAL BRITTLENESS TEMPERATURE USING DWTT PROCEDURE

1.1 The procedure is applicable to the test specimens cut out from the base metal of steel pipes with a diameter equal to and exceeding 300 mm, wall thickness exceeding 7,5 mm and from rolled sheets, skelps (hereinafter referred to as "plate") of the same thickness as for their manufacture. The test consists of impact bend loading of a specimen with the stress concentrator provided by a free falling weight or impact-testing machine pendulum till fracture. A series of 10 specimens is usually tested at room and low temperatures (two specimens per the temperature) to determine the percentage of ductile component in fractures and drawing up the fiber percentage to temperature ratio. As a result, the following shall be determined:

the temperature, at which the specimens meet the criterion to the specified content of fiber component in the fracture;

average and minimum content of fiber component in the fracture at the base temperature for the steel grade to be tested.

The pipe sample (billet) shall be cut out transverse to the pipe longitudinal axis in compliance with Fig. 1.1. The plate sample (billet) shall be cut out transverse to the rolled product axis from the first quarter of the plate width.

The quantity of pipes or plates to be tested is given in Table 4.2.3.5.1.1, unless otherwise specified. When a sample (billet) is cut out using flame cutting the machining allowance shall be at least 15 mm from the cut line to the specimen edge.

The pipe sample straightening shall be carried out using static loading. After completion of straightening the bend deflection shall prevent the specimen from rotation in the plane of load application during the test. It is permitted to use specimens with their midsection has not been straightened at the length equal to two thicknesses; in this case, simultaneous straightening of both sample ends is recommended.

General requirements for specimen straightening are similar to those given in Section 2 of the present Appendix for CTOD-tested specimens.

Where there is a difference in test results obtained on straightened and non-straightened specimens, the preference shall be given to non-straightened specimens at arbitration tests.

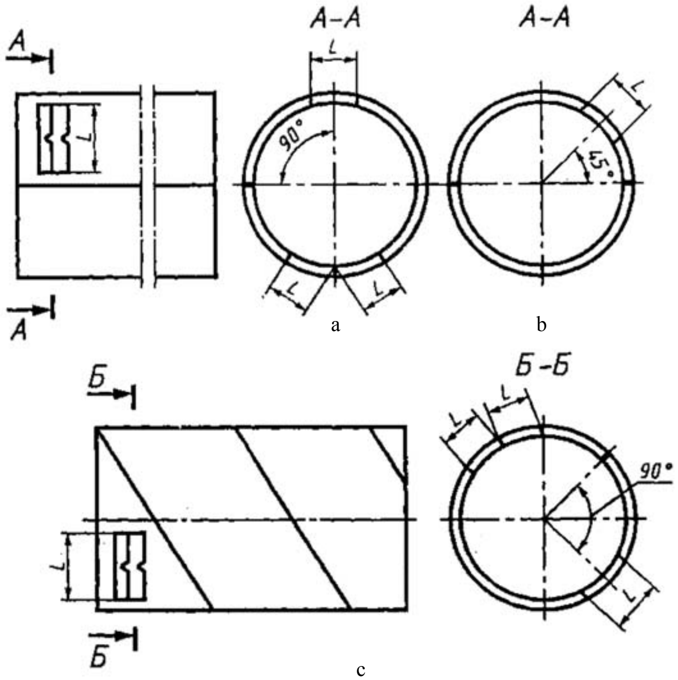


Fig. 1.1
Specimen cut out:
a – longitudinal welded pipe with one longitudinal seam; *b* – longitudinal welded pipe with two longitudinal seams; *c* – spiral welded pipe; *L* is a specimen length

1.2 The tests shall be conducted on prism specimens with a notch on a surface in tension, from which crack propagation under impact loads may take place (Fig. 1.2). Milled notch is not permitted. Pressed (*a*) and chevron notches are permitted (*b*).

In addition to percentage of fiber component it is reasonable to register the energy consumed for the specimen destruction.

Basic diagram of appliers recommended for pressing-in the concentrators and dimensions of the hob working section are shown on Fig. 1.3. The chevron notch is made using the disk cutter or metal slitting saw, radius at its top is not specified.

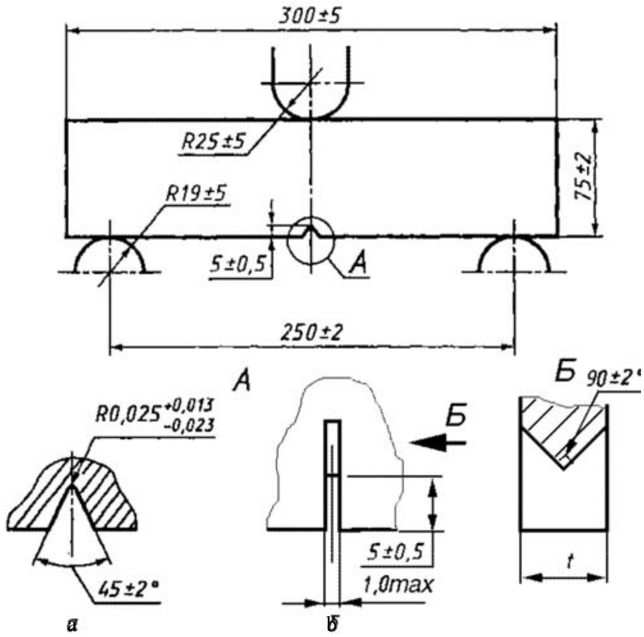


Fig. 1.2
Specimen and testing equipment (t – thickness)

The required capacity of an impact-testing machine may be evaluated using the formulae:

$$KDWT_p = 5{,}93\ t^{1{,}5}\ KV^{0{,}544}; \tag{1.1}$$

$$KDWTT_{ch} = 3{,}95\ t^{1{,}5}\ KV^{0{,}544} \tag{1.2}$$

where *KDWTT* = *DWTT* impact energy with a chevron (*ch*) and pressed notch (*p*);
t = specimen thickness, in mm;
KV = impact energy, in J.

The specimen is mounted on supports in such a way that the impact of striker shall break the test specimen from the side opposite to the concentrator. The specimen shall be placed in such a way as to provide the concentrator symmetrical

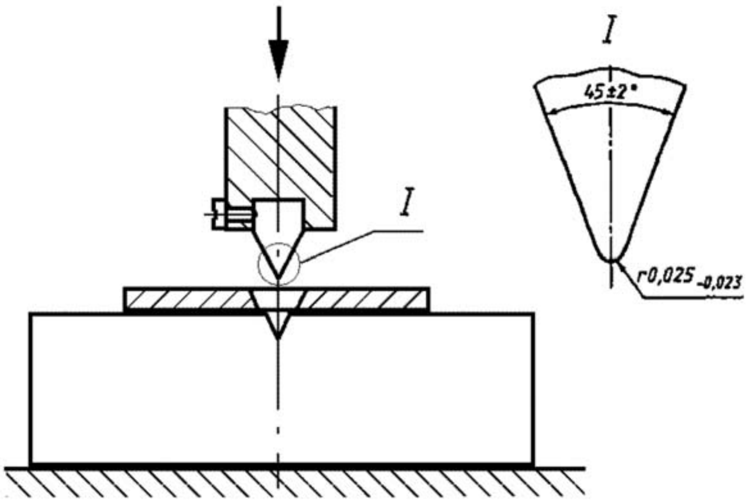


Fig. 1.3
Notch pressing-in device

location to supports and its axis shall be aligned with the striker center line within ± 2 mm. The specimen shall be mounted on supports of the impact-testing machine and be supported by special thrusts in such a way as to prevent its axial rotation under impact when tested. The impact velocity shall be not less than 5 m/s and, preferably, not more than 6 m/s.

The specimens are cooled in liquid (alcohol) at the temperature equal to the test temperature with an accuracy of ± 2 °C. The specimens with thickness equal to 19 mm or less shall be soaked for at least 15 min in a cooling bath after reaching the specified temperature. The specimens with thickness exceeding 19 mm shall be soaked on the basis of 1 min per 1 mm of thickness. Pre-cooling in cryochamber is permitted.

The specimens shall be taken out from the thermostatic bath and be broken within 10 s maximum. Where the specimens are continuously tested within the period exceeding 10 s after being taken out from the bath, they shall be re-cooled to the temperature determined experimentally, and the temperature measurement shall be carried out to the moment of impact using a thermocouple inserted into the specimen orifice at least 15 mm deep.

1.3 When determining percentage of ductile component in the fractures of specimens with thickness up to and equal 19 mm, consideration shall not be given to fracture sections *t* (specimen thickness) adjacent to the concentrator and to the striker impact place (Fig. 1.4). For the specimens with thickness exceeding 19 mm, consideration shall be given to fracture sections with length equal to *t*, but not to 19 mm

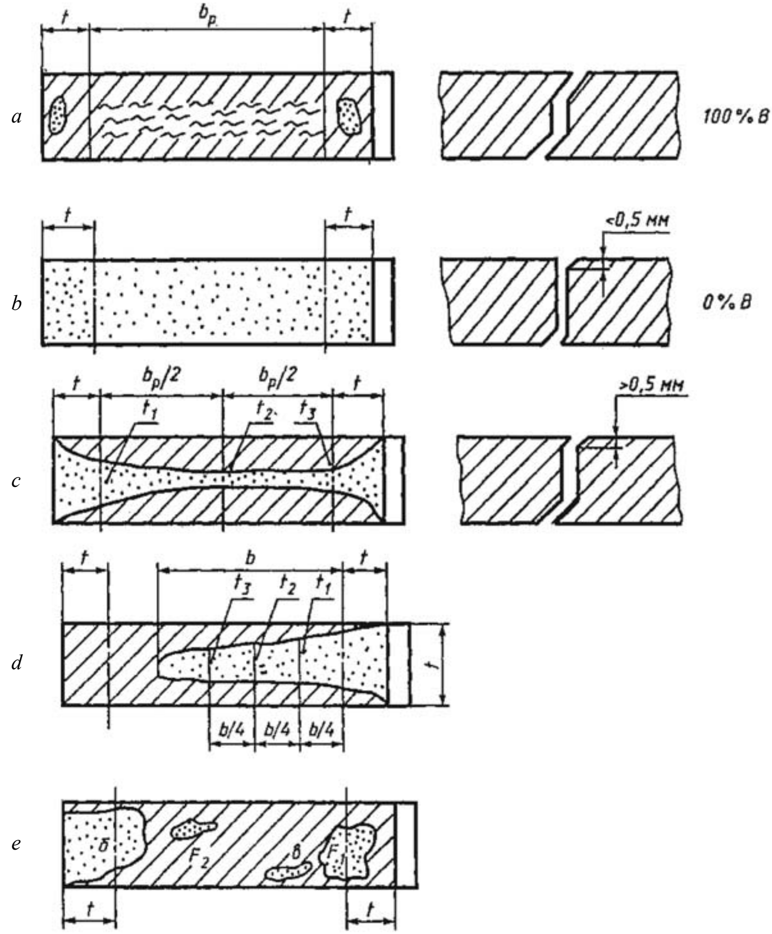
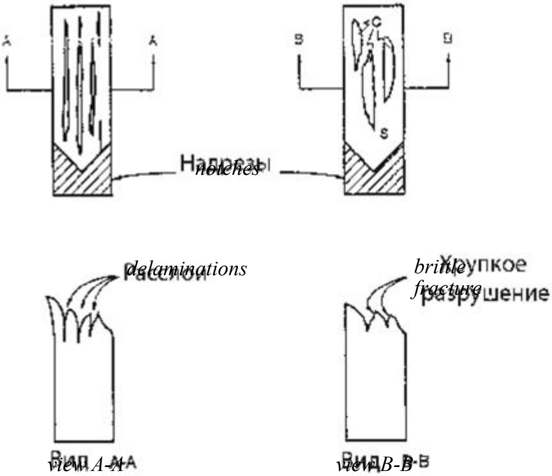


Fig. 1.4
The procedure of determining the crystalline section area and fiber percentage



Note: brittle component is not considered in delaminations, when calculating the fiber component area.

Note: brittle component is considered in delaminations, when calculating the fiber component area.

Fig. 1.5
Accounting procedure of the area of crystal spots in fracture

from each side. Where there are fracture laminations, consideration shall not be given to crystalline sections normal to fracture surface at the open laminations (Fig. 1.5).

The fracture ductile component percentage B, %, is calculated using the formula

$$B = (F_{ac} - F_{cr}) / F_{ac} \cdot 100\ \% \qquad (1.3)$$

where F_{ac} – test fracture area, in mm^2;
F_{cr} – crystal fracture section(s) area, in mm^2.

The ductile fracture surface looks dim grey with typical "fibers" and is usually located at an angle to the specimen lateral surface. The brittle fracture surface looks crystalline, without visible signs of plastic deformation on the fracture surface. The brittle fracture sections are usually adjacent to the concentrator base and impact area. The brittle fracture area is usually determined as follows:

by measuring the brittle fracture area with the aid of machine area computation using a photograph or optical projection of the fracture surface;

by visual comparison of the fracture surface with the reference specimens or their photographs, on which the brittle component percentage has been predetermined;

by measuring the brittle fracture sections and calculating their total area.

Where the crystalline fracture with the shear lips less than 0,5 mm, it is considered to have nil ductility percentage. In borderline cases it is permitted to use the formulae:

to Fig. 1.4, c:

$$B = \left(1 - \frac{t_1 + t_2 + t_3}{3\,t}\right) \cdot 100\%; \tag{1.4}$$

to Fig. 1.4, d:

$$B = \left(1 - \frac{(t_1 + t_2 + t_3) \cdot b}{3\,t\,b_p}\right) \cdot 100\%; \tag{1.5}$$

to Fig. 1.4, e:

$$B = \left(1 - \frac{\sum F_i}{t\,b_p}\right) \cdot 100\%. \tag{1.6}$$

The ductile component percentage in a fracture determined using the present procedure is within ± 3 % of accuracy with a confidence factor P equal to 95 %.

If non-compliance with the temperature conditions, wrong specimen alignment, misalignment of load application in relation to the concentrator axis and other malfunctions of the impact-test machine have been detected during the tests, as well as if the specimen has proved to be defective or poorly prepared, irrespective of whether it was detected before or after the specimen fracture, the test results shall be considered invalid and repeated tests shall be carried out on the same number of specimens. Where the specimen was not broken after the first impact, it may be broken after the second impact; in this case, the obtained fiber percentage shall be considered the lower bound and shall be specified in the report.

The test results shall be included in the report containing the information specified in 4.2.3.3.4 and the following:

maximum impact energy margin during the tests;

load-lifting height;

impact velocity.

Test results are presented in the form of the following table:

Item No.	T, °C	Thickness, in mm	Net-height, in mm	Area to be tested, in mm^2	Crystalline area, in mm^2	Fiber percentage	Note

2 DETERMINATION OF CTOD

To determine the CTOD value specimens with a notch and fatigue ptecracked specimens are used. Cutting out of specimens and notching on heat-affected zone (HAZ) shall be carried out after final heat treatment, in this case, the notch location – through-specimen-thickness, and the crack propagation direction shall be transverse to the pipe.

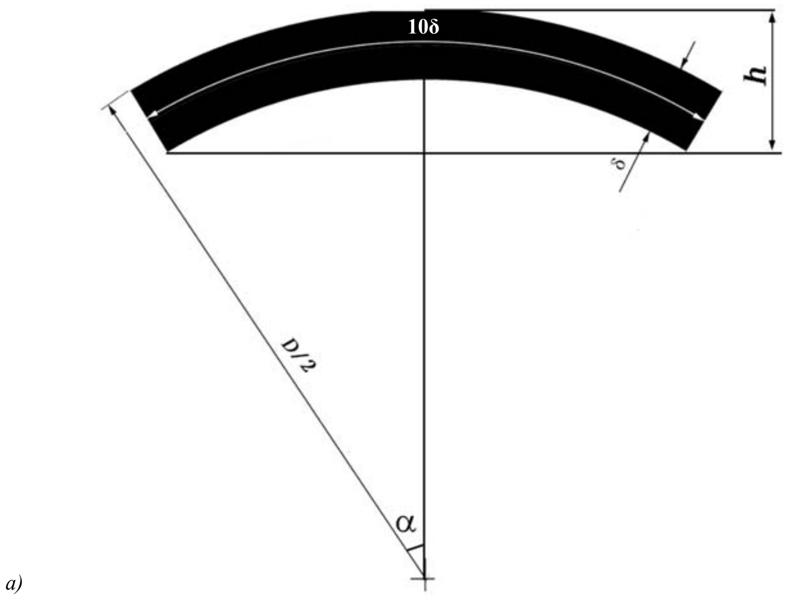
As the test result is considerably determined by the specimen thickness, the latter shall be assigned as far as possible close to the base metal thickness. For pipe metal, especially as regards the transverse specimens, billet straightening is inevitable. To limit the plastic deformation additionally induced in the notched zone, the billet straightening in the form of a “gull wing” is recommended (Fig. 2.1). After that the through-billet-thickness mechanical treatment may be carried out.

Lateral pittings up to 20 per cent of thickness are permitted on specimens, except for the notched zone (at least one thickness to both sides from the notch).

Table 2.1

Billet straightening properties for three-point bend test

Wall thickness δ to outside diameter D ratio	Height of non-straightened billet h	First procedure: straightening of the whole billet to the height h_1	Second procedure: straightening of billet ends	Thickness of the three-point impact bend test specimen
$\leq 0,05$	$\leq 1,3\delta$	δ	Not required	$\leq 0,95\delta$
0,07	$2,3\delta$	$\geq 1,4\delta$	Required	$\leq 0,95\delta$
0,09	$3,4\delta$	$\geq 2,5\delta$	Required	$\leq 0,95\delta$ With permitted pittings
$> 0,09$	$> 3,4\delta$	Compact specimens are recommended		



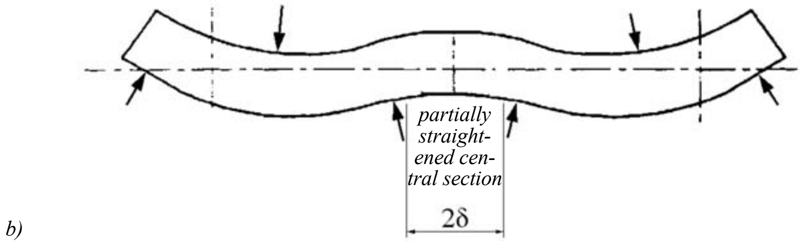


Fig. 2.1
Transverse pipe billet straightening

Preference shall be given to bend-type specimens; the specimen height is equal to the doubled width (Fig. 2.2).

The specimens shall be tested using testing machine with the crosshead-movement rate under quasistatic load providing the stress intensity factor K_f growth within 0,5-3,0 MPa·m^{0,5}/s. In the course of the tests, a deformation curve shall be plotted as

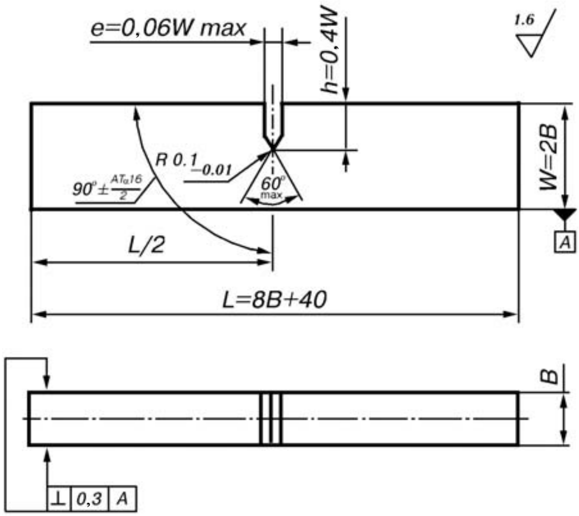


Fig. 2.2
Preferred specimen type for CTOD tests

"load – crack edge opening" coordinate system. The specimen shall be loaded up to total or partial destruction or until the load reaches its maximum value. Verification of compliance with the correctness conditions shall be carried out after test completion.

The angle between the notch line and lateral surfaces of the specimen shall be within the range 90 ± 5°.

When testing the pipe base metal, the preparatory edge milling procedure is recommended to be carried out, as it is described in the welded specimen testing procedure (refer to Section 5 "Welding"). The necessity of stress relieving using such method may be determined experimentally on the test specimen.

After completion of specimens manufacture the fatigue crack growth at room temperature shall be conducted. The cyclic loading regime shall be chosen in compliance with the three following conditions:

maximum value of F_f – cycle load at the final stage of crack propagation shall not exceed

$$F_f = \frac{B\,(W-a)^2\,(\sigma_{yts}+\sigma_{ytp})}{4S} \tag{2.1}$$

where B = specimen thickness;
W = specimen height;
a = current length of a crack;
S = span;
σ_{yts}, σ_{ytp} = yield stress and tensile strength of the material at the crack growth temperature;

maximum cyclic value of stress intensity factor K_f shall not exceed

$$K_f/E = 3{,}2\ 10^{-4}\ \mathrm{m}^{0{,}5} \tag{2.2}$$

where E = modulus of elasticity;

in tests obtaining the correct K_{1c} values of material the K_f value shall not exceed

$$K_f = 0{,}6\ \frac{\sigma_{yts}}{\sigma_{ys}}\ K_{1c} \tag{2.3}$$

where σ_{ys} = material yield stress at test temperature.

For low-alloyed steels, calculations made according to Formula (2.1), as a rule, result in less load values, as compared to those according to Formula (2.2), and the correctness conditions of K_{1c} are not met even at the lowest test temperature. In this case, Formula (2.3) is not used when choosing the load.

The load at the initial stage of fatigue crack growth shall be additionally limited: not exceeding $1{,}3K_f$-level with the crack equal to the notch depth.

Testing procedure:

to scale deformation curves meeting the standard recommendations to slope angle of the curve elastic segment and to curve dimensions in Y-axis direction;

to calibrate crack opening sensors;

to mount the specimen on supports, to fit crack opening sensor and to cool up to specified testing temperature;

to load the specimen at the specified crosshead rate. The specimens shall be loaded up to unstable fracture (obvious break of deformation curve) or until obvious exceeding of maximum load. After that the crack opening sensor is removed and complete destruction of the specimen is performed at the test temperature.

to make all necessary measurements in the specimen fracture: length of initial fatigue crack and value of stable crack extension, if any.

The test load shall be measured with an accuracy of at least ± 1 per cent. The crack edges opening shall be measured with an accuracy exceeding

± 0,003 mm when measuring the displacements up to 0,3 mm and ± 1 per cent with larger displacements. Prior to commencement of testing, the specimen thickness B and height W shall be measured with an accuracy of ± 0,1 per cent. When testing the bend-type specimen, the span shall be within $S = 4W \pm 0{,}2W$ and the mounting accuracy shall be ± 1 per cent of S with regard to the load application – notch alignment line. The temperature shall be measured with an accuracy of ± 2 °C, actions shall be taken to the specimen thickness temperature equalization.

Where a pop-in is available, number n is considered significant and the CTOD value shall be determined just for this event if condition $d_n\% > 5\ \%$ is met, where the value of d_n, in per cent, shall be determined using graphical plotting (Fig. 2.3) by the formula

$$d_n\%\,F_1 = 100\left(1 - \frac{D_1}{F_1}\left(\frac{F_n - y_n}{D_n + x_n}\right)\right)\% \qquad (2.4)$$

where F = load;
D = displacement.

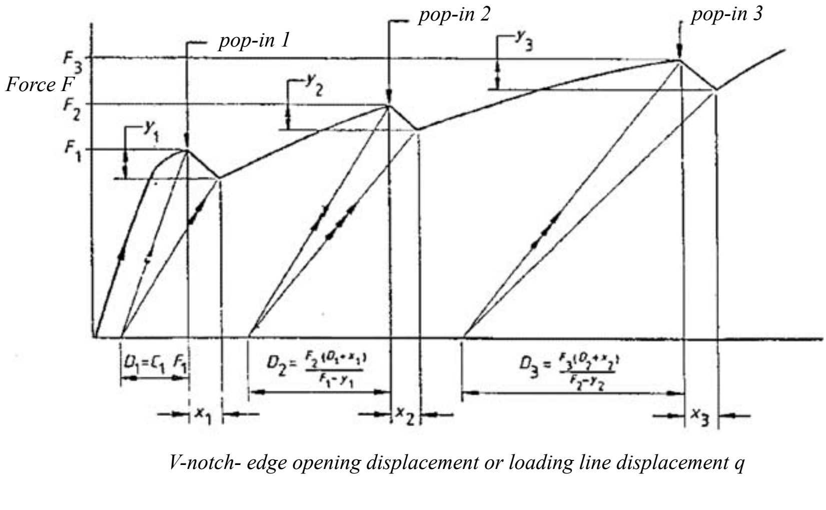


Fig. 2.3
The assessment procedure of pop-in significance on the deformation curve

The fatigue crack length in the fracture shall be measured at nine equidistant points along the specimen cross-section with an accuracy not less than ± 0,25 per cent of the average length. Extreme measurements shall be made at a distance of 1 per cent of the specimen width from the surface. The average length of the initial fatigue crack a_0 shall be calculated as a sum of seven internal measurements and half a sum of two near-surface measurements divided by eight. The difference between any two out of seven internal crack length measurements shall not exceed 10 per cent of the average crack length.

Checking of a_0/W ratio is additionally required: it shall be within the range of $0{,}45 < a_0/W < 0{,}55$.

Calculation of CTOD value (designated as δ in formulae) shall be carried out using the formula

$$\delta = \left[\frac{FS}{BW^{1,5}} \cdot f\left(\frac{a_0}{W}\right)\right]^2 \frac{(1-\mu^2)}{2\sigma_{ys}E} + \frac{0{,}4\,(W-a_0)\,Vp}{0{,}4\,W + 0{,}6\,a_0 + z} \tag{2.5}$$

where F = load at the selected point on the curve;
v_p = relevant ductile component of displacement;
E, μ = modulus of elasticity and Poisson's ratio of material;
σ_{ys} = yield stress of selected material at the test temperature.

The value of function $f(a_0/W)$ shall be determined by the following ratio:

$$f(a_0/W) = \frac{3\,(a_0/W)^{0,5}\,[1{,}99-(a_0/W)\,(1-a_0/W)\,(2{,}15-3{,}93a_0/W+2{,}7a_0^2/W^2)]}{2\,(1+2\,a_0/W)\,(1-a_0/W)^{1,5}}. \tag{2.6}$$

The value of σ_{ys} for the test temperature T [°C], unless known form the experiment, may be determined by the formula

$$\sigma_{ys} = \sigma_{yts} + 10^5/(491 + 1{,}8\,T) - 189. \tag{2.7}$$

Test results are recommended to be presented as follows:

Standard №		Steel grade	
Type of metal products		No. of cast	
Condition of material (weld etc.)		No. of plate	
Nominal thickness, in mm		Billet marking	
Type of specimen		Welding procedure №	
Orientation of crack		Marking of specimen	
Geometrical parameters			
Thickness b, in mm		b after compression, in mm	
Width W, in mm		Overall height C, in mm	
Span S, in mm		Half-height H, in mm	
Notch depth h, in mm		Orifice diameter d, in mm	
Thickness of prismatic edges z, in mm		Semi-distance between orifices h, in mm	
Crack propagation parameters			
Final maximum crack load F_f, kN			
Minimum-maximum load ratio, R		Total number of cycles, N	
Temperature and strength			
Test temperature, in °C		Yield stress σ_{yts}, in MPa	
Tensile strength σ_{ytp}, in MPa		At a test temperature σ_{ys}, in MPa	
Fracture			

	a_1	a_2	a_3	a_4	a_5	a_6	a_7	a_8	a_9	Average	Note
a											
Δa											

Presence of an arrested brittle crack extension		Welding defects	
Metal splitting parallel to the surface		"Steps" in the fracture	

Test results interpretation					
K_Q, MPa$\sqrt{\text{м}}$			Critical event		
F_{max} / F_Q			CTOD , mm		
Metallography (for specimens from the heat-affected zone)					
Target structure to the scribe line					
Metallography results	Weld	HAZ at the fusion line	HAZ distant	Base metal	Finding: target structure
%					

Enclosures: fracture photographs, load curve records.

3 DETERMINATION OF CAPABILITY TO WITHSTAND PLASTIC DEFORMATIONS

Bend tests on the mandrel are mandatory for the face-, root- and side-bends (side-bend tests shall be carried out for welds only).

Face-bend tests shall be carried out on full-thickness specimens with rolled surface. Pre-deformation between two planes is permitted only for specimens with the inner pipe surface to be extended in tension, as stipulated by the personnel safety requirements. Side-bend straightening of specimens is not recommended.

Where the plate thickness is up to 32 mm, the specimen thickness shall be equal to the plate thickness; where the thickness exceeds 32 mm, it is permitted to carry out specimen planning up to the thickness of 25 mm on one side. The specimen width shall range from 1,6 to 5 thicknesses. The specimen length shall be $L = 2\,(a + d) + 100^{+50}$ mm, where a is the specimen thickness, d is the mandrel diameter.

For side-bend use is made of ground smooth with thickness of 10 mm.

Test specimens shall be taken from the areas near those from which specimens for other tests have been cut out to compare bend test results with other material properties. Sectioning using guillotine shears is not permitted. When mechanical treatment is completed, the specimen edges shall be free from transverse grooves made with the cutter. Roughness of mechanically treated surface shall not exceed R_z 40 micron. Sharp edges shall be rounded to the radius not exceeding $0{,}1a$.

Unless otherwise specified in the regulatory documents on metal products, the mandrel diameter shall comply with those given in Table 3.1, the mandrel hardness shall be from 55 to 60 HRC along the loading surface. The width of supports shall exceed the specimen width. The diameter of support rolls shall be from 30 to 50 mm. Clear distance between supports, unless otherwise specified in the regulatory documents on metal products, shall be taken equal to $d + 2{,}5\,a$.

Table 3.1

Mandrel diameter during bend tests

Minimum guaranteed yield stress of base metal, in MPa	Face-bend/root-bend mandrel diameter (*a* is the specimen thickness)	Side-bend mandrel diameter, in mm (specimen thickness is 10 mm)
Not higher than 390	$2a$	30
420 – 620	$4a$	40
690 and higher	$6a$	60

The tests consist of bend loading of specimens by concentrated load at the mid-span between supports at the room temperature (Fig. 3.1, *a*, *b*).

In case the specimen is free from visible defects during the test, loading shall be applied until the required bending angle is achieved. When the load is removed, the specimen shall be tested for defects on its tension and side surfaces at the required bending angle.

In case there are visible defects on the specimen in the course of the test, loading shall be stopped. After removal of load the specimen shall be tested for defects on its tension and side surfaces at the achieved bending angle.

Side surfaces, edges and external surface of the specimen curved section shall be examined. Determination of test results regarding permissibility of defects detected shall be carried out in compliance with the regulatory and technical documentation on metal products. Unless otherwise specified, the specimen is considered as having passed the test when it is free from visible fracture, delaminations, tears and cracks.

The bending angle, if it is less than 180°, shall be measured in accordance with Fig. 3.1, *e* after removal of load.

The specimen sides shall be bent to an angle of 180° till they are parallel (Fig. 3.1, *c*) or contact each other (Fig. 3.1, *d*). Bending on supports is permitted till the bend angle reaches 140°.

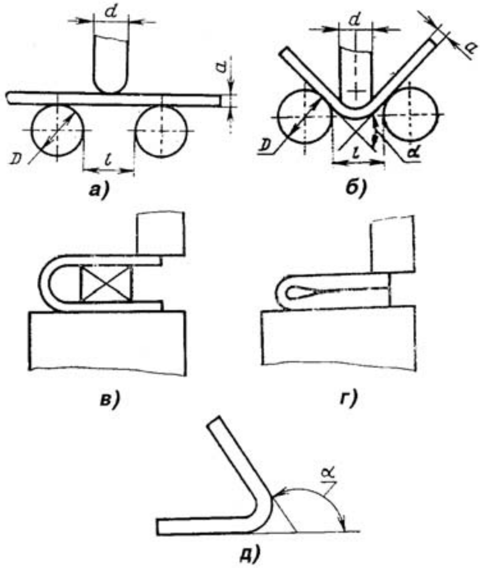


Fig. 3.1
Bend test

4 PROCEDURE FOR DETERMINING SULPHIDE STRESS CRACKING RESISTANCE

The tests shall be carried out on three specimens taken from each batch of pipes. Unless otherwise specified in the regulatory documents on metal products, the test environment will be a solution containing a sodium chloride aqua solution – 5 % NaCl and glacial acetic acid – 0,5 % CH_3COOH (pH of solution is 2,7) saturated with hydrogen sulphide at the pressure of 0,1 MPa.

The tests shall be carried out at a permanent four-point bend loading of a full-thickness specimen or at tensioning of the cylindrical specimen being soaked in the test solution within 720 hours under the stresses of 85 per cent of the specified minimum yield stress for pipes. The acceptance criterion – the absence of cracks proceeding from results of magnetic flaw detection and metallographic examination on macrosections after the test.

5 DETERMINATION OF HYDROGEN-INDUCED CRACKING

The tests shall be carried out on three specimens taken from each batch of pipes. Unless otherwise specified in the regulatory documents on metal products, the test environment will be a solution containing sodium chloride aqua solution – 5 % NaCl and glacial acetic acid – 0,5 % CH_3COOH (pH of solution is 2,7) saturated with hydrogen sulphide with the concentration of 3000 ppm at the pressure of 0,1 MPa.

The specimens shall be soaked in the test solution within 96 hours, whereupon the quantity of cracks in specimens shall be assessed.

The specimen size shall be 100 × 20 mm × product thickness.

Upon the Register request the quantitative assessment of the absorbed hydrogen (diffusion in glycerin within 72 hours at the temperature of 45 °C).

Internal cracking shall be assessed using micrograph method (section cutting and crack measurement), criterion

$$\mathrm{CLR} = \sum l_i / L \cdot 100\ \% \qquad (5.1)$$

where l_i = length of i-crack on a section of L × product thickness size;

or ultrasonic testing (mapping with assessment of the cracked surface percentage, smoothing equal to 12 dB), criterion

$$\mathrm{TAS} = n / N \cdot 100\ \% \qquad (5.2)$$

where n = number of cracked areas to be assessed;
N = total number of areas to be assessed (for standard specimen N = 48, the area size shall be 6,67 × 6,67 mm).

APPENDIX 5

DETERMINATION OF VALUES OF WAVE PARTICLE VELOCITIES AND ACCELERATIONS IN BOTTOM LAYER

1. The components of wave particle velocity and acceleration in bottom layer $V_{w,x}$, $V_{w,z}$, $a_{w,x}$, $a_{w,z}$ are determined by Tables 1 to 4, depending on:

h – seawater depth in way of the pipeline section in question, in m;

H – wave height with 1 % probability per year, in m;

τ – wave period with 1 % probability per year, in s.

The intermediate values of velocity and acceleration components are determined by linear interpolation.

2. The values of H and τ are determined on the basis of a hydrometeorological engineering survey lengthwise of the subsea pipeline route. The Register Reference Data on Wind and Wave Conditions may be used for specifying the wave height and period with 10^{-2} 1/year probability for those regions of sea water areas (pipeline route sections) wherein these values were determined.

The design values of velocity V_w and acceleration a_w are determined by the formulae:

$$V_w = \sqrt{V^2_{w,x} + V^2_{w,z}} \quad (1)$$

$$a_w = \sqrt{a^2_{w,x} + a^2_{w,z}} \quad (2)$$

Table 1

Horizontal component of velocity $V_{w,x}$, in m/s

Seawater depth h = 10 m					
Wave period τ, s	**Wave height H, m**				
	1	**2**	**3**	**4**	**5**
5	0,24	0,48	0,72	0,96	1,11
7	0,37	0,74	1,10	1,45	1,75
9	0,43	0,88	1,32	1,74	2,11
11	0,47	0,98	1,48	1,95	2,35
13	0,51	1,06	1,60	2,10	2,52
15	0,53	1,13	1,70	2,22	2,65

Seawater depth h = 20 m					
Wave period τ**, s**	**Wave height** H**, m**				
	1	**3**	**6**	**8**	**10**
5	0,051	0,168	–	–	–
7	0,163	0,492	0,996	1,315	1,514
9	0,235	0,709	1,417	1,863	2,248
11	0,275	0,841	1,690	2,224	2,692
13	0,301	0,932	1,890	2,488	3,011
15	0,319	1.004	2,050	2,695	3,254
Seawater depth h **= 30 m**					
Wave period τ**, s**	**Wave height** H**, m**				
	1	**3**	**6**	**10**	**15**
5	0,010	0,037	–	–	–
7	0,075	0,229	0,479	0,834	–
9	0,145	0,437	0,881	1,471	2,065
11	0,191	0,575	1,156	1,916	2,744
13	0,219	0,665	1,343	2,230	3,205
15	0,237	0,727	1,481	2,470	3,551
Seawater depth h **= 40 m**					
Wave period τ**, s**	**Wave height** H**, m**				
	1	**5**	**10**	**15**	**20**
5	0,002	0,018	–	–	–
7	0,034	0,182	0,418	–	–
9	0,091	0,462	0,951	1,436	–
11	0,138	0,694	1,393	2,073	2,629
13	0,169	0,852	1,708	2,533	3,246
15	0,189	0,962	1,939	2,877	3,697

Table 1 continued

Seawater depth h = 50 m					
Wave period τ, s	**Wave height H, m**				
	1	**10**	**15**	**20**	**25**
5	0,0001	–	–	–	–
7	0,015	0,205	–	–	–
9	0,057	0,609	0,953	–	–
11	0,101	1,027	1,552	2,050	2,344
13	0,133	1,345	2,014	2,650	3,183
15	0,155	1,576	2,357	3,099	3,746
Seawater depth h = 70 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
7	0,017	0,049	–	–	–
9	0,111	0,243	–	–	–
11	0,272	0,557	1,177	1,476	–
13	0,427	0,860	1,744	2,177	2,565
15	0,546	1,096	2,196	2,730	3,226
Seawater depth h = 100 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
7	0,002	0,006	–	–	–
9	0,026	0,060	–	–	–
11	0,104	0,216	0,488	0,642	–
13	0,218	0,442	0,922	1,177	1,435
15	0,330	0,663	1,345	1,693	2,042
Seawater depth h = 125 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
7	–	0,001	–	–	–
9	0,008	0,018	–	–	–
11	0,046	0,097	0,230	0,312	–
13	0,123	0,250	0,533	0,691	0,858
15	0,216	0,436	0,893	1,133	1,379

Seawater depth h = 150 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
9	0,002	0,006	–	–	–
11	0,020	0,043	0,108	0,151	0,193
13	0,068	0,140	0,305	0,402	0,507
15	0,141	0,285	0,589	0,752	0,923

Table 2

Vertical component of velocity $V_{w,z}$, in m/s

Seawater depth h = 10 m					
Wave period τ, s	**Wave height H, m**				
	1	**2**	**3**	**4**	**5**
5	0,04	0,08	0,11	0,14	0,16
7	0,04	0,07	0,11	0,14	0,16
9	0,03	0,06	0,09	0,12	0,15
11	0,03	0,06	0,09	0,12	0,14
13	0,02	0,05	0,08	0,11	0,14
15	0,02	0,05	0,08	0,11	0,13
Seawater depth h = 20 m					
Wave period τ, s	**Wave height H, m**				
	1	**3**	**6**	**8**	**10**
5	0,008	0,026	–	–	–
7	0,014	0,042	0,081	0,101	0,111
9	0,014	0,041	0,079	0,100	0,117
11	0,012	0,037	0,072	0,093	0,110
13	0,011	0,033	0,066	0,087	0,105
15	0,010	0,030	0,062	0,083	0,101

Table 2 continued

Seawater depth h = 30 m					
Wave period τ, s	**Wave height H, m**				
	1	**3**	**6**	**10**	**15**
5	0,002	0,006	–	–	–
7	0,006	0,019	0,038	0,060	–
9	0,008	0,023	0,046	0,073	0,094
11	0,008	0,023	0,044	0,071	0,095
13	0,007	0,021	0,041	0,066	0,091
15	0,006	0,019	0,038	0,061	0,087
Seawater depth h = 40 m					
Wave period τ, s	**Wave height H, m**				
	1	**5**	**10**	**15**	**20**
5	–	0,003	–	–	–
7	0,003	0,014	0,030	–	–
9	0,005	0,023	0,046	0,065	–
11	0,005	0,025	0,049	0,069	0,083
13	0,005	0,024	0,047	0,067	0,082
15	0,005	0,022	0,044	0,063	0,079
Seawater depth h = 50 m					
Wave period τ, s	**Wave height H, m**				
	1	**10**	**15**	**20**	**25**
7	0,001	0,015	–	–	–
9	0,003	0,029	0,043	–	–
11	0,004	0,035	0,051	0,064	0,069
13	0,004	0,035	0,051	0,065	0,075
15	0,003	0,034	0,049	0,062	0,073

Seawater depth h = 70 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
7	0,001	0,003	–	–	–
9	0,005	0,011	–	–	–
11	0,009	0,018	0,036	0,043	–
13	0,011	0,021	0,041	0,050	0,056
15	0,011	0,022	0,042	0,050	0,058
Seawater depth h = 100 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
9	0,001	0,003	–	–	–
11	0,003	0,007	0,015	0,019	–
13	0,005	0,011	0,021	0,026	0,031
15	0,006	0,012	0,024	0,030	0,035
Seawater depth h = 125 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
9	–	0,001	–	–	–
11	0,002	0,003	0,007	0,009	–
13	0,003	0,006	0,012	0,015	0,018
15	0,004	0,008	0,016	0,020	0,024
Seawater depth h = 150 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
11	0,001	0,001	0,003	0,004	–
13	0,002	0,003	0,007	0,009	0,011
15	0,003	0,005	0,010	0,013	0,016

Table 3

Horizontal component of acceleration $a_{w,x}$, in m/s^2

Seawater depth h = 10 m					
Wave period τ, s	**Wave height H, m**				
	1	**2**	**3**	**4**	**5**
5	0,30	0,60	0,90	1,17	1,33
7	0,32	0,64	0,94	1,22	1,45
9	0,29	0,58	0,86	1,13	1,37
11	0,26	0,52	0,80	1,07	1,32
13	0,23	0,49	0,77	1,04	1,29
15	0,21	0,47	0,75	1,02	1,27
Seawater depth h = 20 m					
Wave period τ, s	**Wave height H, m**				
	1	**3**	**6**	**8**	**10**
5	0,064	0,211	–	–	–
7	0,146	0,439	0,881	1,149	1,300
9	0,163	0,485	0,950	1,230	1,460
11	0,155	0,463	0,905	1,178	1,416
13	0,142	0,427	0,851	1,119	1,364
15	0,129	0,395	0,808	1,078	1,326
Seawater depth h = 30 m					
Wave period τ, s	**Wave height H, m**				
	1	**3**	**6**	**10**	**15**
5	0,013	0,046	–	–	–
7	0,067	0,205	0,429	0,741	–
9	0,101	0,304	0,609	1,005	1,372
11	0,108	0,324	0,643	1,046	1,459
13	0,105	0,314	0,621	1,009	1,426
15	0,098	0,294	0,585	0,961	1,381

Seawater depth *h* = 40 m					
Wave period τ, s	**Wave height *H*, m**				
	1	**5**	**10**	**15**	**20**
5	0,003	0,023	–	–	–
7	0,030	0,163	0,374	–	–
9	0,064	0,322	0,660	0,985	–
11	0,079	0,393	0,782	1,145	1,421
13	0,081	0,404	0,797	1,159	1,456
15	0,079	0,391	0,770	1,123	1,426
Seawater depth *h* = 50 m					
Wave period τ, s	**Wave height *H*, m**				
	1	**10**	**15**	**20**	**25**
5	0,001	–	–	–	–
7	0,013	0,184	–	–	–
9	0,040	0,424	0,661	–	–
11	0,058	0,582	0,874	1,141	1,282
13	0,064	0,639	0,945	1,226	1,447
15	0,065	0,640	0,942	1,220	1,453
Seawater depth *h* = 70 m					
Wave period τ, s	**Wave height *H*, m**				
	5	**10**	**20**	**25**	**30**
7	0,015	0,044	–	–	–
9	0,078	0,170	–	–	–
11	0,155	0,318	0,668	0,833	–
13	0,206	0,414	0,832	1,031	1,203
15	0,228	0,454	0,898	1,105	1,292
Seawater depth *h* = 100 m					
Wave period τ, s	**Wave height *H*, m**				
	5	**10**	**20**	**25**	**30**
7	0,001	0,005	–	–	–
9	0,018	0,042	–	–	–
11	0,059	0,123	0,279	0,365	–
13	0,105	0,213	0,444	0,566	0,688
15	0,138	0,277	0,560	0,703	0,845

Table 3 continued

Seawater depth h = 125 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
7	–	0,001	–	–	–
9	0,005	0,013	–	–	–
11	0,026	0,055	0,131	0,178	–
13	0,059	0,121	0,257	0,334	0,413
15	0,091	0,183	0,373	0,473	0,575
Seawater depth h = 150 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
9	0,002	0,004	–	–	–
11	0,011	0,025	0,062	0,086	–
13	0,033	0,068	0,148	0,194	0,244
15	0,059	0,119	0,246	0,315	0,386

Table 4

Vertical component of acceleration $a_{w,z}$, in m/s²

Seawater depth h = 10 m					
Wave period τ, s	**Wave height H, m**				
	1	**2**	**3**	**4**	**5**
5	0,05	0,10	0,15	0,18	0,21
7	0,03	0,07	0,11	0,14	0,17
9	0,03	0,05	0,09	0,12	0,15
11	0,02	0,05	0,08	0,11	0,14
13	0,02	0,04	0,07	0,10	0,13
15	0,01	0,04	0,07	0,10	0,13

Seawater depth h = 20 m					
Wave period τ, s	**Wave height H, m**				
	1	**3**	**6**	**8**	**10**
5	0,010	0,033	–	–	–
7	0,013	0,039	0,074	0,089	0,103
9	0,010	0,029	0,057	0,075	0,091
11	0,007	0,023	0,048	0,064	0,080
13	0,006	0,019	0,042	0,058	0,074
15	0,005	0,017	0,039	0,054	0,069
Seawater depth h = 30 m					
Wave period τ, s	**Wave height H, m**				
	1	**3**	**6**	**10**	**15**
5	0,002	0,007	–	–	–
7	0,006	0,017	0,035	0,055	–
9	0,005	0,016	0,033	0,050	0,068
11	0,004	0,013	0,026	0,042	0,061
13	0,003	0,011	0,022	0,037	0,055
15	0,003	0,009	0,019	0,033	0,050
Seawater depth h = 40 m					
Wave period τ, s	**Wave height H, m**				
	1	**5**	**10**	**15**	**20**
5	–	0,003	–	–	–
7	0,002	0,013	0,028	–	–
9	0,003	0,017	0,033	0,046	–
11	0,003	0,015	0,028	0,040	0,050
13	0,002	0,012	0,024	0,035	0,045
15	0,002	0,010	0,020	0,031	0,041

Table 4 continued

Seawater depth *h* = 50 m					
Wave period τ, s	**Wave height *H*, m**				
	1	**10**	**15**	**20**	**25**
7	0,001	0,013	–	–	–
9	0,002	0,021	0,031	–	–
11	0,002	0,020	0,030	0,036	0,041
13	0,002	0,017	0,025	0,032	0,039
15	0,001	0,015	0,022	0,029	0,035
Seawater depth *h* = 70 m					
Wave period τ, s	**Wave height *H*, m**				
	5	**10**	**20**	**25**	**30**
7	0,001	0,003	–	–	–
9	0,004	0,008	–	–	–
11	0,005	0,011	0,021	0,025	0,000
13	0,005	0,011	0,020	0,024	0,027
15	0,005	0,009	0,017	0,021	0,025
Seawater depth *h* = 100 m					
Wave period τ, s	**Wave height *H*, m**				
	5	**10**	**20**	**25**	**30**
9	0,001	0,002	–	–	–
11	0,002	0,004	0,009	0,011	–
13	0,003	0,005	0,011	0,013	0,015
15	0,003	0,005	0,010	0,013	0,015
Seawater depth *h* = 125 m					
Wave period τ, s	**Wave height *H*, m**				
	5	**10**	**20**	**25**	**30**
9	–	0,001	–	–	–
11	0,001	0,002	0,004	0,005	–
13	0,001	0,003	0,006	0,008	0,009
15	0,002	0,003	0,007	0,009	0,010

Seawater depth h = 150 m					
Wave period τ, s	**Wave height H, m**				
	5	**10**	**20**	**25**	**30**
11	–	0,001	0,002	0,003	–
13	0,001	0,002	0,003	0,004	0,005
15	0,001	0,002	0,004	0,006	0,007

Российский морской регистр судоходства

Правила классификации и постройки морских подводных трубопроводов

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Rules for the Classification and Construction of Subsea Pipelines

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РОССИЙСКИЙ МОРСКОЙ РЕГИСТР СУДОХОДСТВА
ГЛАВНОЕ УПРАВЛЕНИЕ
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КАСАТЕЛЬНО: ***Изменения в Правилах классификации и постройки морских подводных трубопроводов, 2009 НД 2-020301-002 и Rules for the Classification and Construction of Subsea Pipelines, 2009 НД 2-020301-002-E***	Ввод в действие	*с момента получения*		
	Срок действия до		Срок действия продлен до	
	Отменяет/изменяет/дополняет циркулярное письмо № --- от			
ОБЪЕКТ НАБЛЮДЕНИЯ: ***Код объекта технического наблюдения 23000000***	Количество страниц	*1*		

Приложения: *нет*

Зам.генерального директора ______ (подпись) ***В.И. Евенко*** (Ф.И.О.)

Вносит изменения в ***правила РС***	Название НД и № *Правила классификации и постройки морских подводных трубопроводов, 2009 НД 2-020301-002 и Rules for the Classification and Construction of Subsea Pipelines, 2009 НД 2-020301-002-E*

В Правила классификации и постройки морских подводных трубопроводов, 2009 НД 2-020301-002 и Rules for the Classification and Construction of Subsea Pipelines, 2009 НД 2-020301-002-E вносится следующее изменение:

1.4.5.2 Текст пункта заменить на:
«Документом, подтверждающим выполнение требований Правил МПТ, является Классификационное свидетельство морского подводного трубопровода».

Данное изменение будет внесено в Правила классификации и постройки морских подводных трубопроводов и Rules for the Classification and Construction of Subsea Pipelines при переиздании.

Необходимо выполнить следующее:

1) Ознакомить инспекторский состав, а также заинтересованные организации в районе деятельности подразделений РС, с содержанием настоящего циркулярного письма.
2) Применять требования, введенные настоящим циркулярным письмом, при подготовке документов Регистра по результатам первоначальных освидетельствований морских подводных трубопроводов.

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