NATURAL GAS PIPELINE SAFETY (CONSTRUCTION, OPERATION AND MAINTENANCE) REGULATIONS, 2012 (L.I. 2189)

ARRANGEMENT OF REGULATIONS

IN exercise of the power conferred on the Minister responsible for Energy by subsection (1) of section 56 of the Energy Commission Act 1997 (Act 541), these Regulations are made this 3rd day of August, 2012.

Scope and application

Regulation 1—Purpose

The purpose of these Regulations is to provide consistent, uniform standards and procedures for the safe construction, operation and maintenance of natural gas facilities and installations throughout the country.

Regulation 2—Scope and application of Regulations

(1) These Regulations prescribe the minimum safety standard requirements for

(a) the construction, operation and maintenance of pipeline facilities for the transportation of natural gas including transportation within the territorial waters and exclusive economic zone of the Republic;

(b) the selection and qualification of pipes and components of a pipeline;

(c) the design of pipelines;

(d) the welding of steel materials in pipelines;

(e) the joining of materials in pipelines other than by welding and outside the course of the manufacture of pipes or pipeline components;

(f) the installation of customer meters, service regulators, service lines, service line valves and service line connections to the mains;

(g) the protection of metallic pipelines from external, internal and atmospheric corrosion;

(h) testing of pipelines;

(i) uprating of pipelines;

(j) persons qualified to perform tasks on a pipeline facility;

(k) integrity management programmes on pipelines; and

(l) the abandonment or decommissioning of pipeline facilities.

(2) These Regulations apply to the

(a) procedures established by the Commission for the design, construction, installation, operation and maintenance of pipelines;

(b) enforcement procedures that ensure the safety of pipelines, and

(c) reporting procedures for incidents, safety related conditions, maintenance and annual pipeline summary data.

(3) These Regulations are subject to the West African Gas Pipeline Act, 2004 (Act 681).

(4) These Regulations do not apply to

(a) pipelines, which are gas producer operated without a connection to a licensed gas transmission facility; and

(b) pipelines, which are used for the purpose of petroleum activities.

(5) The, Commission is responsible for the effective implementation of these Regulations.

Regulation 3—Documents available to the public

A person may access a document or other information held by the Commission in respect of the standards prescribed by the organizations specified in the Sixteenth Schedule.

Class locations

Regulation 4—Class locations

(1) For the purpose of the classification of pipeline locations,

(a) a “class location unit” is an onshore area that extends two hundred and one metres on either side of the centreline of any continuous length of pipeline of two kilometres; and

(b) each separate dwelling unit in a multiple dwelling unit building shall be counted as a separate building intended for human occupancy.

(2) Subject to subregulation (3),

(a) a Class 1 location is

(i) an offshore area, or

(ii) a class location unit that has less than ten buildings intended for human occupancy;

(b) a Class 2 location is a class location unit that has more than ten but less than fifty buildings intended for human occupancy;

(c) a Class 3 location is

(i) a class location unit that has more than fifty buildings intended for human Occupancy; or

(ii) an area where the pipeline lies within ninety-one metres of a building or a small, well-defined outside area, including a playground, recreation area, outdoor theatre, market, lorry park or other place of public assembly; and

(d) a Class 4 location is a class location unit where buildings with more than four storeys above ground are prevalent.

(3) The length of class locations may be adjusted as follows:

(a) a Class 4 location ends two hundred and one metres away from the nearest building with more than four storeys above ground, or

(b) to end two hundred and one metres away from the nearest building for the class location in a cluster, where a cluster of buildings intended for human occupancy requires a Class 2 or Class 3 location.

Standard requirements

Regulation 5—Requirement to comply with standards

(1) A person shall not commence the construction of a pipeline unless that pipeline has been designed in accordance with the requirements of these Regulations.

(2) A person shall not replace or relocate a segment of a pipeline unless it has been

(a) designed,

(b) tested,

(c) installed, and

(d) inspected

in accordance with the requirements of these Regulations.

Regulation 6—Operation of a segment of a pipeline

(1) A person shall not operate a pipeline or segment of a pipeline unless it is done in accordance with these Regulations.

(2) A person shall not operate a segment of a pipeline which is replaced, relocated or otherwise changed unless that replacement, relocation or change has been made in accordance with these Regulations.

(3) An operator shall maintain, modify as appropriate and follow any plan, procedure or programme required for the safety of the pipeline in accordance with these Regulations.

Authorisation to construct or operate a pipeline

Regulation 7—Application to construct or operate a pipeline

(1) A person shall not commence the construction, installation, operation or modification of a pipeline without the prior written approval of the Commission.

(2) A person who intends to construct or operate a pipeline shall apply to the Commission in the form determined by the Board and accompanied with

(a) the design duly verified by a reputable third party, and

(b) other documents and fees determined by the Board.

(3) The Commission shall

(a) within ten working days of the receipt of an application acknowledge receipt, and

(b) within sixty days after the ten days inform the applicant in writing of the decision of the Board.

(4) Subject to the Energy Commission Act, 1997 (Act 541), the Commission shall grant the authorisation to construct or operate a pipeline unless there is a reason founded on technical data, national security, public safety or other reasonable justification, which shall be communicated to the applicant.

(5) The Commission may for stated reasons modify, suspend or cancel the authorisation, which has been granted only after it has considered any representation or objection made by the applicant.

Material requirements and pipeline design

Regulation 8—Material requirements

A person who intends to construct or operate a pipeline shall ensure that the material to be used for the purpose

(a) has the capacity to maintain the structural integrity under the temperature and other environmental conditions anticipated,

(b) is chemically compatible with the gas to be transported and any other material in the pipeline with which the gas will be in contact, and

(c) meets the requirements specified in the Second Schedule.

Regulation 9—Pipeline design

A person shall not install a pipeline unless the pipeline is

(a) of a design with a sufficient wall thickness as specified in the Second Schedule, and

(b) installed with adequate protection to withstand any anticipated external pressure or load which can be imposed on the pipe after the installation.

Welding

Regulation 10—Qualification of welder

(1) A person shall not weld any material in a pipeline unless that person is certified by a recognised person appointed by the Energy Commission.

(2) A certified welder may qualify to weld on a pipe to be operated at a pressure that produces a hoop stress of less than twenty per cent of the specified minimum yield strength by conducting an acceptable test weld, for the process to be used under the test set forth in the paragraph 1 of the Seventeenth Schedule.

(3) Despite subregulations (1) and (2), a certified welder who intends to make a welded service line connection to a main shall first perform an acceptable test weld as indicated under paragraph 2 of the Seventeenth Schedule as a requirement of the qualifying test.

Regulation 11—Guidelines for certification of certified welders

The Energy Commission shall issue guidelines for the certification of certified welders within six months after the commencement of these Regulations.

Regulation 12—Register of certified welders

The Energy Commission shall keep and maintain a register of persons certified to undertake welding of a material in a pipeline.

Regulation 13—Welding procedures

(1) A certified welder shall carry out the welding of a material in a pipeline in accordance with the welding procedures provided under the Seventeenth Schedule to meet the requirements of the Fourth Schedule.

(2) The Commission shall designate an authority to inspect welding carried out in accordance with these Regulations.

Regulation 14—Protection from weather

A certified welder shall ensure that the welding operation is protected from any weather condition that is likely to impair the quality of the completed weld.

Joining of material other than by welding

Regulation 15—Design and installation of pipeline by joining

(1) A person who designs and installs a pipeline shall ensure that each joint can sustain the longitudinal pull out or thrust force caused by contraction or expansion of the piping or by anticipated external or internal loading.

(2) Without limiting subregulation (1), each joint shall be made in accordance with written procedures that have been proved by test or experience to produce gastight joints.

(3) The Commission shall designate a person to inspect each joint to ensure compliance with the requirements of the Fifth Schedule.

Construction requirements for pipeline facilities

Regulation 16—Compliance with specifications or standards

A person who constructs a pipeline facility shall do so in accordance with a comprehensive written specification as indicated in the Sixth Schedule.

Regulation 17—Inspection

(1) The Commission shall authorise a person to inspect each pipeline facility to ensure that the construction meets the standards specified in the Sixth Schedule.

(2) The authorised person shall inspect the length of pipe and component of a pipeline facility at the site of the installation to ensure that it has not sustained any determinable damage, which could impair its serviceability.

Customer meters, service regulators, service lines and excess flow valve

Regulation 18—Location

A person who installs a customer meter, service regulator or excess flow valve shall ensure that it is in a readily accessible location.

Regulation 19—Protection

A person who installs a customer meter, service regulator, service line or excess flow valve shall protect it against

(a) corrosion and other damage, and

(b) anticipated vehicular damage if installed outside a building.

Regulation 20—Performance of excess flow valve

Subject to these Regulations, a person who installs a new service line or replaces a service line shall install an excess flow valve that meets the performance standards specified in paragraph 7.45 of the Seventh Schedule as part of the installation or replacement process, if the line will

(a) operate continuously throughout the year at a pressure of not less than 69 kPa, and

(b) serve a single customer.

Customer notification

Regulation 21—Excess flow valve

(1) The operator shall notify the service line customer of the need to install an excess flow valve as part of the installation or replacement process as follows:

(a) in respect of a new service line, when the customer applies for the service; and

(b) in respect of a replaced service line, when the operator determines that the service line will be replaced.

(2) Where the service line customer requests for the installation of an excess flow valve, the operator shall install the excess flow valve at a mutually agreed date.

(3) For the purpose of subregulation (1), the notice shall include the following details:

(a) an explanation to the customer that an excess flow valve that meets the performance standards specified in paragraph 7.45 of the Seventh Schedule, is available for the operator to install if the customer bears the costs associated with the installation;

(b) an explanation to the customer of the potential safety benefits that may be derived from the installation of an excess flow valve;

(c) that an excess flow valve is designed to shut off the flow of natural gas automatically where the service line breaks;

(d) a description of the installation, maintenance and replacement costs;

(e) a requirement that the customer bears the costs associated with installation; and

(f) the periodic cost structure for the installation of the excess flow valve.

Regulation 22—Buried service line

If an operator is not responsible for the maintenance of a customer's buried service line, that operator shall notify that customer in writing of the following information:

(a) that the operator is not responsible for the maintenance of the customer's buried piping;

(b) that if the customer's buried piping is not maintained, it is likely to suffer the potential hazards of corrosion;

(c) that buried piping should be

(i) periodically inspected for leaks,

(ii) periodically inspected for corrosion if the piping is metallic, and

(iii) repaired if any unsafe condition is discovered;

(d) that the piping should be located in advance and the excavation done by hand when excavating near buried gas piping; and

(e) that the operator and a plumbing contractor can assist in locating, inspecting and repairing the customer's buried piping.

Regulation 23—Requirement for record

An operator shall make the following records available for inspection by the Commission:

(a) a copy of the notice of the installation or replacement of a service line currently in use, and

(b) a copy of any notice sent to a service line customer within the preceding three years of the installation of the service line.

Regulation 24—Exception to notification requirement

The notification requirements under regulation 21 do not apply if the operator can prove that

(a) the operator will voluntarily install an excess flow valve,

(b) the excess flow valve that meets the performance standards under paragraph 7.45 of the Seventh Schedule are not available to the operator,

(c) the operator has prior knowledge of contaminants in the gas stream that could

(i) interfere with the operation of an excess flow valve,

(ii) cause loss of service to a residence, or

(iii) interfere with any necessary operation or maintenance activity, and

(d) an emergency or short time notice replacement situation made it impractical for the operator to notify a service line customer before replacement of a service line, including the situation where an operator has to replace a service line quickly because of

(i) third party excavation damage,

(ii) a Grade 1 leak, or

(iii) a request at short notice for the relocation of a service line.

Requirements for corrosion control

Regulation 25—Corrosion control procedures

(1) Subject to paragraphs 8.3 and 8.6 of the Eighth Schedule the operator shall protect each buried or submerged pipeline against external corrosion and ensure the following conditions:

(a) the provision of an external protective coating that meets the requirements of paragraph 8.11 to 8.15 of the Eighth Schedule;

(b) the provision of a cathodic protection system that is designed to protect the pipeline installed; and

(c) the operation of the pipeline within one year after the completion of construction.

(2) A person qualified in the discipline of pipeline corrosion control or another person under the direction of that person shall conduct corrosion control procedures in accordance with requirements set out under paragraph 8.2 of the Eighth Schedule.

Regulation 26—General requirements for testing the leak strength of pipeline

A person shall not operate a new segment of a pipeline or return to service a segment of a pipeline which has been relocated and eliminated.

Uprating

Regulation 27—Pressure increase

Where it is required that an increase in operating pressure be made in increments, the operator shall in accordance with the requirements of the Tenth Schedule, increase the pressure gradually at a rate which can be controlled.

Regulation 28—Records

An operator who uprates a segment of pipeline shall retain for the life of the segment a record of each pressure test conducted, in connection with the uprating.

Regulation 29—Written procedure

An operator who uprates a segment of pipeline shall establish a written procedure in accordance with the Tenth Schedule to ensure that each applicable requirement is complied with.

Operations, maintenance and procedures

Regulation 30—Procedural manual for operations, maintenance and emergency

(1) An operator shall prepare and follow a manual of written procedures in accordance with the Eleventh and Twelfth Schedules for

(a) conducting operations and maintenance activities, and

(b) emergency response for each pipeline before carrying out an operation on a pipeline system.

(2) The written procedures include procedures for abnormal operations.

(3) The operator shall

(a) keep appropriate parts of the manual at a location where operations and maintenance activities are conducted; and

(b) review and update the manual at least once each year or at intervals of not more than fifteen months.

(4) The Commission may, after giving written notice and an opportunity for hearing, require an operator to amend its operating plans and procedures when necessary to provide a reasonable level of safety.

Regulation 31—Requirement to maintain pipeline

(1) A person shall not operate a segment of a pipeline, unless it is maintained in accordance with the Eleventh and Twelfth Schedules.

(2) An operator shall replace, repair or remove from service each segment of pipeline, which becomes unsafe.

(3) An operator shall repair a hazardous leak promptly.

Regulation 32—Use of line markers for buried mains and transmission lines

An operator shall ensure that a line marker is placed and maintained as close as practical over each buried main or transmission line

(a) at each crossing of a public road and railway; and

(b) whenever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

Regulation 33—Exceptions for use of line markers

Despite regulation 32, line markers are not required for the following pipelines:

(a) mains and transmission lines located offshore, or at crossings of or underwater ways and other water bodies;

(b) mains in Class 3 or 4 locations where a damage prevention programme is in operation as provided for in paragraph 11.16 to 11.21 of the Eleventh Schedule; or

(c) transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

Regulation 34—Caption for line markers

An operator shall ensure that the following is written legibly on a background of a sharply contrasting colour on each line marker:

(a) the word “Warning”, “Caution”, or “Danger” followed by the words “Gas Pipeline”; and

(b) the name of the operator and telephone number, on which the operator can be reached at all times.

Regulation 35—Caption for line markers in prominently developed urban areas

(1) Without limiting regulation 34, the letters on each line marker located in a prominently developed urban area shall be at least twenty-five millimetres high with six millimetres stroke.

(2) For the purposes of this regulation, a “prominently developed urban area” means

(a) a class location unit that has forty-six or more buildings including where buildings with four or more storeys above ground are prevalent and intended for human occupancy; or

(b) an area where the pipeline lies within ninety-one meters of a building or a well-defined outside area.

(3) For the purposes of paragraph (b) of subregulation (2), a well defined outside area includes a playground, recreation area, an outdoor theater, or other place of public assembly, that is occupied by twenty or more persons on at least five days in each week for ten weeks in a twelvemonth period but the days and weeks need not be consecutive.

Regulation 36—Pipeline above ground

An operator shall place and maintain a line marker along each section of a main or transmission line, which is located above ground in an area accessible to the public.

Regulation 37—Record keeping of transmission line

An operator shall maintain records for transmission lines as follows

(a) the date, location and description of each repair made to a pipeline shall be retained for as long as the pipe remains in service;

(b) the date, location and description of each repair made to any part of a pipeline system shall be retained for at least five years, except for a repair generated by a patrol, survey, inspection or test required under the Eleventh and Twelfth Schedules; and

(c) a record of each patrol, survey, inspection, and test required under the Second to Twelfth Schedule shall be retained for at least five years or until the next patrol, survey, or test is completed, whichever is longer.

Qualification of pipeline personnel

Regulation 38—Qualification programme for covered task

(1) An operator shall develop a written qualification programme as specified in the Thirteenth Schedule and submit it to the Commission for approval.

(2) An operator shall verify the qualification of an individual who intends to perform a covered task before that individual undertakes the performance of that task.

Regulation 39—Covered task

A covered task is an activity, identified by the operator which is required to be performed on a pipeline facility

(a) as an operation or maintenance task, and

(b) which affects the operation or integrity of a pipeline.

Pipeline integrity management

Regulation 40—Integrity management programme

An operator of a covered pipeline segment shall establish, follow and continuously review an integrity management programme which contains the elements specified in paragraph 14.8 to 14.21 of the Fourteenth Schedule which address the risk on each covered transmission pipeline segment.

Regulation 41—Additional preventive and mitigative measures

(1) Except as otherwise provided in these Regulations, an operator shall take additional measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area.

(2) The operator shall base the additional measures on any threat the operator has identified in respect of each pipeline segment.

Regulation 42—Third party damage

An operator shall enhance its damage prevention programme required under paragraph 14.125 of the Fourteenth Schedule with respect to a covered segment to prevent and minimise the consequences of a release due to third party damage.

Regulation 43—Operator records

An operator shall maintain, for the useful life of a pipeline, records that demonstrate compliance with the requirements of these Regulations.

Regulation 44—Notification

An operator shall notify the Commission of a matter required in these Regulations by

(a) post or hand delivery to the Office of the Energy Commission,

(b) facsimile, or

(c) electronic mail.

Cessation of operation of facilities

Regulation 45—Abandonment or decommissioning of facilities

(1) An operator shall in the conduct of the abandonment or decommissioning of a pipeline

(a) disconnect from every source and supply of gas and purge gas from an inactive pipeline which is not being maintained, and

(b) fill a pipeline with water or inert material and seal the ends of an offshore pipeline if it is an inactive pipeline which is not being maintained.

(2) When service to a customer is discontinued, an operator shall

(a) provide the customer with a loading device or other device to prevent the opening by an unauthorised person of the valve that prevents the flow of gas,

(b) install in the service line or in the meter assembly a mechanical device or fitting which will prevent the flow of gas, and

(c) disconnect physically the customer's piping from the gas supply and the open pipe ends that are sealed.

(3) Where air is used in purging, an operator shall ensure that a combustible mixture is not present after purging.

(4) The operator shall fill each abandoned vault with a suitable compacted material.

(5) In the case of each abandoned offshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator shall file a report on the abandonment of that facility.

(6) An operator shall submit a report in respect of the abandonment of a pipeline to the Commission.

Procedural requirements for pipeline safety

Regulation 46—Service of documents

(1) Each directive, notice or other document required to be served shall be served personally, by courier or by registered mail.

(2) Service on a person's duly authorised representative or agent constitutes effective service.

(3) Service by registered mail is complete on mailing.

(4) An official Ghana Postal Service receipt from registered mailing constitutes prima facie evidence of service.

Regulation 47—Notice of amendment of plan or procedure

(1) The Commission may issue a notice of amendment to an operator to determine whether an operator's plan or procedure required under these Regulations is inadequate in order to ensure the safe operation of a pipeline facility.

(2) The operator shall submit written comments within thirty days after receipt of the notice.

(3) After consideration of the written documents, the Commission shall

(a) determine whether a plan or procedure is inadequate as alleged; and

(b) order the required amendment if adequate; or

(c) withdraw the notice if inadequate:

(4) In the determination of the adequacy of the plan or procedure of an operator, the Commission shall consider

(a) relevant available pipeline safety data,

(b) whether the plan or procedure is appropriate for the particular type of pipeline transportation of facility, and for the location of the facility, and

(c) the extent to which the plan or procedure contributes to public safety.

Annual safety reports, incident reports and safety-related condition reports

Regulation 48—Telephone notice of incidents

(1) An operator shall at the earliest practicable moment after discovery of an incident, give notice to the Commission.

(2) The notice may be by telephone to a number specified by the Commission and include the following information:

(a) the name of the operator or person who makes the report and the respective telephone number,

(b) the location of the incident,

(c) the time of the incident,

(d) the number of fatalities and personal injuries if any, and

(e) any other relevant fact that is known by the operator to be connected to the cause of the incident or extent of the damage.

Regulation 49—Written reports

(1) An operator of a gas distribution, transmission or gathering pipeline shall submit a separate written report in accordance with regulation 50 to 57 as applicable.

(2) Each written report required by these Regulations shall be submitted to the Commission.

Regulation 50—Incident report for distribution pipeline system

(1) Subject to subregulation (3), an operator of a distribution pipeline system shall submit an incident report to the Commission within thirty days after detection of an incident required to be reported under regulation 48.

(2) When additional relevant information is obtained after the report is submitted under subregulation (1), the operator shall make a supplementary report where necessary with a clear reference by date and subject to the original report.

(3) The submission of the report is not required in the case of a master meter system.

Regulation 51—Annual report for distribution pipeline system

An operator of a distribution pipeline system shall submit to the Commission, not later than the 15th of March each year, an annual report for that system for the preceding year.

Regulation 52—Incident report for transmission and gathering system

(1) An operator of a transmission or a gathering pipeline system shall submit to the Commission a report within thirty days after detection of an incident required to be reported under regulation 48.

(2) Where additional related information is obtained after a report is submitted under subregulation (1), the operator shall make a supplementary report as soon as practicable with a clear reference by date and subject to the original report.

Regulation 53—Annual report for transmission and gathering systems

An operator of a transmission or a gathering pipeline system shall submit to the Commission, not later than the 15th of March of each year, an annual report in respect of that system for the preceding year.

Regulation 54—Report format and forms

(1) Subject to subregulation (2), the format of an annual report and a copy of the prescribed incident report form are available on request at the Office of the Commission.

(2) A copy of the prescribed incident report form may be reproduced and used in addition if it is of the same size and texture of paper as the original report form.

(3) Despite subregulation (1), an operator may with the consent of the Commission submit the information required by the incident report form by any other means acceptable to the Commission.

Regulation 55—Report on safety related conditions

(1) Subject to subregulation (2), an operator shall make a report in accordance with regulation 56 in respect of the existence of any of the following safety-related conditions involving a facility in service:

(a) in the case of a pipeline that operates at a hoop stress of twenty percent or more of its specified minimum yield strength that general corrosion has reduced the required level for the maximum allowable operating pressure, and localised corrosion pitting to a degree where leakage might result;

(b) the unintended movement or abnormal loading by an environmental cause, including an earthquake, landslide, or flood, that impairs the serviceability of a pipeline, or the structural integrity or reliability of a natural gas facility that contains, controls or processes gas or liquefied natural gas;

(c) a crack or other material defect that impairs the structural integrity or reliability of a natural gas facility that contains, controls or processes gas or liquefied natural gas;

(d) a material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of twenty percent or more of its specified minimum yield strength;

(e) the malfunction or operating error that causes the pressure of a pipeline or natural gas facility that contains or processes gas or liquefied natural gas to rise above its maximum allowable operating pressure level or working pressure for a natural gas facility and the build-up allowed for the operation of a pressure limiting or control device;

(f) a leak in a pipeline or natural gas facility that contains or processes gas or liquefied natural gas that constitutes an emergency;

(g) an inner tank leakage, ineffective insulation or frost heave that impairs the structural integrity of a liquefied natural gas storage tank; or

(h) a safety-related condition that could lead to an imminent hazard and require direct or indirect remedial action of the operator for a purpose other than abandonment, a twenty percent or more reduction in operation pressure or the shutdown of operation of a pipeline or a natural gas facility that contains or processes gas or liquefied natural gas.

(2) A report is not required for a safety-related condition that

(a) exists on a master system or a customer-owned service line;

(b) is an incident or results in an incident before the deadline for filing the safety-related condition report;

(c) exists on a pipeline other than a natural gas facility that is more than two hundred and three metres away from any building that is intended for human occupancy or an outdoor place of assembly; or

(d) can be corrected by repair or replacement in accordance with the applicable safety standards before the deadline for filing the safety-related condition report.

(3) Despite subregulation (2) (c), a report is required for a condition within the right-of-way of an active railway, paved road, street or highway.

Regulation 56—Filing safety related condition reports

(1) The operator shall submit in writing a report of a safety-related condition under regulation 55 within five working days after the day a representative of the operator first determines that the condition exists, but not later than ten working days after that day.

(2) A separate condition may be described in a single report if it is closely related to the general safety condition.

(3) A report shall be titled “safety related condition report” and provide the following information:

(a) the name and principal address of the operator,

(b) the date of the report,

(c) the name, job title, and business telephone number of the person submitting the report,

(d) the name, job title, and business telephone number of the person who determined that the condition exists,

(e) the date the condition was discovered and the date the condition was first determined to exist,

(f) the location of the condition, with reference to the town, city, district or offshore site, and where applicable the nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline,

(g) the description of the condition, including circumstances leading to its discovery, and any significant effect of the condition on safety, and the name of the commodity transported or stored,

(h) the corrective action taken including the reduction of pressure or shut down before the report was submitted, and

(i) the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding the action.

Regulation 57—Filing offshore pipeline condition reports

An operator shall, within sixty days after the completion of the inspection of each of its underwater pipelines, report to the Commission the following information:

(a) the name and principal address of that operator,

(b) the date of the report,

(c) the name, job title and business telephone number of the person submitting the report,

(d) the total number of kilometers of pipeline inspected,

(e) the length and date of installation of each exposed pipeline segment and location, including the location according to the description by the Ghana National Petroleum Corporation or state offshore area and block number tract if available, and

(f) the length and date of installation of each pipeline segment, if different from a pipeline segment identified under paragraph (e).

Inspection and enforcement

Regulation 58—Inspection

(1) An inspector or agent authorised by the Commission, may on presentation of authentic identification, enter, inspect and examine, at a reasonable time and in a reasonable manner, the records and property of a person to determine the compliance of the person with these Regulations.

(2) An inspection may be conducted in the following circumstances:

(a) routine scheduling by the Commission;

(b) the investigation of a complaint received from a member of the public;

(c) information obtained from a previous inspection;

(d) the report from a government Ministry, Department or Agency; and

(e) when considered as appropriate by the Commission or its inspector or authorised agent.

(3) If, after an inspection, the Commission believes that further information is required to determine appropriate action, the Commission may request the operator concerned to furnish the Commission with specific information within thirty days after receipt of the request.

(4) The Commission may require testing of portions of a pipeline facility provided that, before exercising this authority, the Commission makes the necessary effort to agree on a mutually accepted plan with the operator of the facility and where appropriate, the appropriate state agencies involved in the performance of the test.

Regulation 59—Warning letters

(1) When the information obtained from an inspection or from any other appropriate source indicates that further action on the part of the Commission is required, the Commission may issue a warning letter or initiate an enforcement proceeding in accordance with these Regulations.

(2) On determining that there is a likely contravention of these Regulations, the Commission may issue a warning letter to the operator in respect of the probable contravention and advise the operator to rectify the circumstance or be subject to a compliance directive under regulation 65.

Regulation 60—Commencement of enforcement proceeding

(1) The Commission shall begin an enforcement proceeding by service of a notice on a person in respect of the likely contravention.

(2) The notice shall include:

(a) a statement of the law, regulation or directive which the person is alleged to have contravened and a statement of the evidence on which the allegation is based;

(b) a notice of the response options available to the respondent under regulation 61;

(c) the maximum penalty which the person is liable to; and

(d) a statement of the remedial action sought in the form of a compliance directive under regulation 65 where applicable.

(3) The Commission may amend a notice any time before the issuance of a consent directive under regulation 66.

(4) Where an amendment includes any new material allegation of fact, the respondent has the opportunity to respond under regulation 61.

Regulation 61—Response options

(1) A person who receives a notice under regulation 60 shall, within twenty days after the receipt of the notice, respond to the notice by the submission of a written explanation, information or other material in response to any allegation.

(2) Where the notice contains a proposed compliance directive, the person who receives it shall respond as follows:

(a) agree to the proposed compliance directive;

(b) request for a consent directive under regulation 66; or

(c) object to the proposed compliance directive and submit a written explanation, information or other material.

Regulation 62—Finality of enforcement proceeding

(1) The Commission shall prepare a report on an enforcement proceeding commenced under regulation 60 and the report shall include

(a) the inspection report and any other evidence of an alleged contravention;

(b) a copy of the notice of contravention issued under regulation 60;

(c) material submitted by the respondent in response to the notice of a probable contravention;

(d) the Commission's evaluation of the response material submitted by the respondent and the recommendation for final action to be taken by the Commission;

(e) a statement of findings and determination on every material issue, including a determination as to whether each alleged contravention has been proved; and

(f) a statement of action required to be taken by the respondent and the time by which that action ought to be taken if a compliance directive is issued.

(2) The Commission shall submit a copy of the report to the

(a) Minister within one month, and

(b) respondent within two months.

Regulation 63—Appeal against decision of Commission

(1) A person aggrieved by the decision of the Commission may lodge a complaint with the Minister who shall within thirty days after the receipt of the complaint make a decision on it.

(2) Where the Minister fails to make a decision or a person is dissatisfied with the decision of the Minister, that person may pursue the matter in Court.

Investigations and directives

Regulation 64—Report to Commission

Where a person becomes aware of an activity, which constitutes a contravention of these Regulations that person shall report the matter to the Commission for investigation.

Regulation 65—Compliance directive

Where the Commission has reason to believe that a person is engaging in conduct which may result in the contravention of these Regulations or that is detrimental to the public interest, the Commission may issue a compliance directive.

Regulation 66—Consent directive

(1) At any time before the issuance of a compliance directive under regulation 65, the Commission and the respondent may agree to settle the matter.

(2) The Commission shall after the decision under subregulation (1), issue a consent directive.

(3) A consent directive is a final administrative directive.

(4) A consent directive includes

(a) an admission by the respondent of each fact;

(b) an acknowledgement that the notice of the alleged contravention may be used to construe the terms of the consent directive; and

(c) a statement of any action required of the respondent and the time when the action will be accomplished.

Hazardous facility provisions

Regulation 67—Hazardous facility directive

(1) Subject to subregulation (3), where the Commission finds a particular pipeline facility to be hazardous to life or property and has given reasonable notice in accordance with regulation 60, the Commission shall issue a hazardous facility directive requiring the operator of the facility to take corrective action.

(2) Corrective action may include the suspended or restricted use of the facility, physical inspection, testing, repair, replacement or any other action the Commission determines as appropriate.

(3) The Commission may waive the requirement for notice before issuing a directive when it determines that the failure to do so is likely to result in serious harm to life or property.

Regulation 68—Offences and penalties

(1) A person that

(a) willfully interferes or knowingly permits the interference with an offshore gas gathering line; or

(b) willfully and knowingly injures, destroys or attempts to injure or destroy a transmission facility or pipeline facility,

commits an offence and is liable on summary conviction to a fine of not less than one thousand penalty units and not more than five thousand penalty units or to a term of imprisonment not less than four years and not more than ten years or to both the fine and imprisonment on first conviction, and to a fine of not less than two thousand penalty units and not more than ten thousand penalty units or to a term of imprisonment of not less than eight years and not more than twenty years or to both that fine and imprisonment on a subsequent conviction.

(2) A person who willfully and knowingly, defaces, damages, removes or destroys a pipeline sign, right of way marker, or marine buoy commits an offence and is liable on summary conviction to a fine of not more than two thousand penalty units or to a term of imprisonment of not more than five years or to both.

(3) Where the offence under subregulation (2) is continuous, the person who commits the offence is liable on summary conviction to a further fine of two hundred and fifty penalty units for each day during which the offence continues after written notice has been served on the offender by the Commission.

(4) Where a person

(a) fails to comply with an obligation imposed under these Regulations, that person is liable to pay compensation for the damage resulting from the noncompliance to the satisfaction of the court; or

(b) contravenes a provision of these Regulations for which a penalty is not provided, that person commits an offence and is liable on summary conviction to a fine of not more than two hundred and fifty penalty units or to a term of imprisonment of not more than twelve months or to both.

Regulation 69—Assessment considerations

(1) The Court may assess the compensation payable under these Regulations after considering

(a) the nature, circumstances and gravity of an act or omission,

(b) the degree of culpability of the offender,

(c) the offender's past record of offences,

(d) the ability of the offender to pay,

(e) any good faith by the offender in attempting to achieve compliance,

(f) the effect on the offender's ability to continue in business, and

(g) any other relevant matter.

Regulation 70—Interpretation

In these Regulations, unless the context otherwise requires,

“abandoned” means permanently removed from service;

“abnormal operating condition” means a condition that is identified by the operator to be the malfunction of a component or deviation from the normal operations and which may indicate a condition that exceeds design limits of a pipeline or result in a hazard to a person, property or the environment;

“Act” means Energy Commission Act, 1997 (Act 541);

“active corrosion” means continuing corrosion which is likely to result in a condition that is detrimental to public safety;

“assessment” means the use of testing techniques to ascertain the condition of a covered pipeline segment;

“back pressure” means resistance to a moving fluid by obstruction or tight bends in the piping along which it is moving against its direction of flow;

“Board” means the governing body of the Commission established under section 4 of the Act;

“certified welder” means a person qualified to carry out welding of materials in a pipeline and certified by a recognized person appointed by the Energy Commission;

“Commission” means the Energy Commission;

“compressor station” means a facility which helps the transportation of natural gas from one location to another by providing pressure to move the gas;

“costs associated with installation” includes the costs directly connected with the installation of an excess flow valve, costs of parts of a pipeline, labour costs, inventory and procurement costs but excludes maintenance and replacement costs until they are incurred;

“covered pipeline segment” means a covered segment;

“covered segment” means a segment of a gas transmission pipeline located in a high consequence area;

“customer meter” means the meter that measures the transfer of gas from an operator to a customer;

“direct assessment” includes an integrity assessment method that utilises a process to evaluate a certain threat including external corrosion, internal corrosion, stress corrosion cracking to a covered pipeline segment integrity and the gathering and integration of risk factor data, indirect examination or analysis to identify an area of suspected corrosion, direct examination of a pipeline and post assessment evaluation;

“distribution line” means a pipeline other than a gathering or a transmission line;

“evaluation” means a process, established and documented by an operator, to determine an individual's ability to perform a covered task by written examination, oral examination, observation during performance on the job, on the job training or simulation and any other designated form of assessment;

“exclusive economic zone” means the area beyond and adjacent the territorial sea which does not extend beyond two hundred nautical miles from the baseline from which the breadth of the territorial sea is measured;

“facility” means a building or equipment that is provided for a particular purpose;

“gas” means natural gas;

“gas producer operated” means the manoeuvre or control of a pipeline by a person that is engaged in the lifting of gas to the surface of the earth and the gathering, treating, field processing of gas to extract liquid hydrocarbons and field storage;

“gathering line” means a pipeline that transports gas from a current production facility to a transmission line or the main;

“Grade 1 leak” means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous actions until the conditions are no longer hazardous;

“hazardous leak” means a Grade 1 leak;

“hoop stress” means the stress in a pipe wall, acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe, and produced by the fluid in the pipe;

“incident” means

(a) an event that involves a release of gas from a pipeline;

(b) a death or a personal injury that necessitates in-patient hospitalisation;

(c) property damage that is estimated at a value above five thousand Ghana Cedis as a result of gas loss and injury to the operator or other person;

(d) an event that results in an emergency shutdown of a natural gas facility; or

(e) an event that is significant in the judgment of the operator even though it does not meet the criteria of paragraphs (a) and (b);

“installation" means a system of machines or apparatus and accessories set up and arranged for a purpose;

“kpa” means kilopascal which is a .unit of pressure;

“licensed gas transmission facility” means the facility for which a licence is granted by the Commission under section 23 of the Act, to operate exclusively the national interconnected transmission system for the transmission throughout the country of natural gas;

“line marker” means an object or sign that shows the position of a pipeline;

“liquefied natural gas” means natural gas, consisting mainly of methane, that has been liquefied by refrigeration or pressure in order to facilitate storage or transport;

"longitudinal pull out" means the thrust force caused by contraction or expansion of a pipe or external or internal loading of a pipe;

"main" means a distribution line that serves as a common source of supply for more than one service line;

"master meter system" means a pipeline system for distributing gas within but not limited to a definable area of a housing project or an apartment complex from an outside source for resale through a gas distribution pipeline system;

"maximum allowable operating pressure" means the maximum pressure at which a pipeline or segment of a pipeline may be operated under these Regulations;

"Minister" means the Minister responsible for Energy;

"natural gas" means all hydrocarbon fuels which are gaseous under normal atmospheric conditions and includes wet gas, dry gas and residue after the extraction of liquid hydrocarbon fuels from wet gas;

"natural gas facility" means a processing facility that includes a liquefied processing facility;

"offshore" means beyond the line of ordinary low water along that portion of the coast of Ghana, that is in direct contact with the open sea and beyond the line marking the seaward limit of inland waters;

"operator" means a person who engages in the gathering, transmission or distribution of gas by pipeline;

"petroleum activity" means any activity engaged in within and outside Ghana related to the exploration for, development and production of petroleum, the acquisition of data and drilling of wells and the treatment, storage, pipeline transportation and decommissioning and the planning, design, construction, installation, operation and use of any facility for the purpose of the activities;

"pipe" includes a pipe or tubing used in the transportation of gas;

"pipeline" includes each part of the physical facilities through which gas is transported, through a pipe, valve and other appurtenance attached to a pipe, compressor unit, metering station, regulator station, delivery station, holder and fabricated assembly;

"pipeline facility" means a new and existing pipeline, right-of-way, equipment, facility or building used in the transportation of gas or in the treatment of gas during the course of transportation;

"piping" means a long tube made of metal or plastic that is used to transport gas;

"regulator station" means a plant or equipment on a service line that controls the pressure of gas delivered from a high pressure to a pressure provided to a customer;

"replaced service line" means a natural gas service line where the fitting which connects the service line to the main is replaced or the piping connected to the fitting is replaced;

“service line” means a distribution line that transports gas from a common source of supply to an individual customer, two adjacent customers, to multiple residential customers or to commercial and industrial customers served through a meter header or manifold, and normally ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to the customer's piping if there is no meter;

“service line connection” means a joint that connects a distribution line from the source of supply to an individual customer;

“service line customer” means the person who pays the gas bill, or the person who requests the service which is yet to be established;

“service line valve” means a valve that is located in a service line;

“service regulator” means the device on a service line that controls the pressure of gas delivered from a higher pressure to a pressure provided to a customer and which serves one customer or multiple customers; .

“thrust force” means a force that is produced by expulsion of a reaction mass; and

“transmission line” means a pipeline other than a gathering line, that

(a) transports gas from a gathering line or a storage facility to a distribution centre, storage facility, or large volume customer that is not downstream from a distribution centre;

(b) operates at a hoop stress of twenty percent or more of the specific minimum yield; or

(c) transports gas within a storage field.

SCHEDULE

FIRST SCHEDULE

(Regulations 2 and 5)

MATERIAL REQUIREMENTS

Scope

1.1 This Schedule prescribes the minimum requirements for the selection and qualification of pipes and components of pipes.

General requirements

1.2 Material for pipeline components must be

(a) able to maintain the structural integrity under the temperature and other environmental conditions which may be anticipated;

(b) chemically compatible with the gas to be transported and any other material in the pipeline with which the gas will be in contact; and

(c) qualified in accordance with the applicable requirements of this Schedule.

Steel pipe

1.3 A new steel pipe may be used if it has been manufactured in accordance with a listed specification in Part A of the Fifteenth Schedule.

1.4 A steel pipe of an unknown or unlisted specification shall meet the requirements specified in Part B of the Fifteenth Schedule.

1.5 A used steel pipe is qualified for use if it was manufactured in accordance with a listed specification in Part A of the Fifteenth Schedule.

1.6 A new or used steel pipe may be used at a pressure resulting in a hoop stress of less than 41 megapascals where

(a) no close coiling or close bending is to be done, or

(b) an examination indicates that a pipe is in good condition and that it is free of split seams and other defects that would cause leakage.

1.7 If a steel pipe is to be welded but has not been manufactured to a listed specification it must also pass the weldability tests prescribed in paragraph (b) of Part B of the Fifteenth Schedule.

1.8 A steel pipe which has not been previously used may be used as a replacement pipe in a segment of a pipeline if it has been manufactured in accordance with the same specification as the pipe used in constructing the segment of a pipeline.

1.9 A new steel pipe, which has been cold expanded, shall meet the requirements specified in Part A of the Fifteenth Schedule.

Plastic pipe

1.10 A new plastic pipe may be used if it

(a) was manufactured in accordance with Part A of the Fifteenth Schedule, and

(b) is resistant to any chemical with which contact may be anticipated.

1.11 A used plastic pipe may be reused if

(a) it was manufactured in accordance with a specification in Part A of the Fifteenth Schedule,

(b) it is resistant to any chemical with which contact may be anticipated,

(c) it has been used only in natural gas service,

(d) its dimensions are still within the tolerances of the specification to which it was manufactured, and

(e) it is free of any defect.

1.12 For the purpose of paragraphs 1.10 (a) and 1.11 (a), where a pipe of a diameter specified as a listed specification is impractical to use, a pipe of a diameter between the sizes included in a listed specification may be used if it

(a) meets the strength and design criteria required of the pipe specified, and

(b) is manufactured from a plastic compound which meets the criteria for material required of pipe specified in the listed specification.

Marking of materials

1.13 Every valve, fitting, length of pipe and other component shall be marked

(a) in accordance with the prescribed specification or standard to which it was manufactured, except that a thermoplastic fitting shall be marked in accordance with the standard, specified in Part A of the Fifteenth Schedule, or

(b) to indicate the size, material, manufacturer, pressure rating and temperature, and where applicable the type, grade and model.

1.14 Surfaces of a pipe and component, which is subject to stress from internal pressure, shall not be field die-stamped.

1.15 If any item is marked by die-stamping, the die shall have a blunt or rounded edge that can minimise stress concentration.

Transportation of pipe

1.16 An operator shall not use a pipe which has an outer diameter to wall thickness ratio of 70 to 1, or more in a pipeline to be operated at a hoop stress of 200% or more of the specific minimum yield strength which is transported by railway unless the transportation is performed in accordance with the standard specified in Part A of the Fifteenth Schedule.

SECOND SCHEDULE

(Regulations 8, 9 and 37)

PIPELINE DESIGN

Scope

2.1 This Schedule prescribes the minimum requirements for the design of a pipe.

General requirements

2.2 A pipe must be designed with sufficient wall thickness, or must be installed with adequate protection to withstand any anticipated external pressure and load which may be imposed on the pipe after installation.

Design formula for steel pipe

2.3 The design pressure for a steel pipe shall be determined in accordance with the following formula:

P= (2 St/D) x F x E x T

Where:

P= design pressure in Pascal gauge.

S= yield strength in Pascal determined in accordance with paragraphs 2.5 and 2.6.

D= nominal outside diameter of the pipe in millimetres.

t= nominal wall thickness of the pipe in millimetres (If this is unknown, it is determined in accordance with paragraph 2.7 to 2.10. Additional wall thickness required for a concurrent external load in accordance with paragraph 2.2 may not be included in computing pressure design).

F = design factor determined in accordance with paragraph 2.11 to 2.14.

E= longitudinal joint factor determined in accordance with paragraph 2.15.

T = temperature de-rating factor determined in accordance with paragraph 2.16.

2.4 If a steel pipe which has been subjected to cold expansion to meet the specific minimum yield strength is subsequently heated, other than by welding or stress relieving as part of welding, the design pressure is limited to 75% of the pressure determined under paragraph 2.3 if the temperature of the pipe exceeds 482.22°C at any time or is held above 315.56°C for more than one hour.

Yield strength for steel pipe

2.5 Where a pipe is manufactured in accordance with a specification listed in the Fifteenth Schedule, the yield strength required in the design formula in paragraph 2.3 is the specific minimum yield strength stated in the listed specification, if that value is known.

2.6 Where the pipe is manufactured in accordance with a specification not listed in Part A of the Fifteenth Schedule or where the specification or tensile properties are unknown, the yield strength to be used in the design formula specified in paragraph 2.3 shall be one of the following:

(a) if the pipe is tensile tested in accordance with paragraph (d) of Part B of the Fifteenth Schedule it shall be the lowest of the following:

(i) 80% of the average yield strength determined by the tensile test, or

(ii) the lowest yield strength determined by the tensile test, or

(b) if the pipe is not tensile tested as provided in sub-paragraph (a), 165 megapascals.

Nominal wall thickness for steel pipe

2.7 Where the nominal wall thickness for a steel pipe is not known, it shall be determined by the measurement of the thickness of each pipe at quarter points on one end.

2.8 Despite paragraph 2.7, if the pipe is of uniform grade and size, and there are more than ten lengths, only 10% of the individual lengths, but not less than 10 lengths shall be measured, except that in this case, the thickness of the lengths which were not measured shall be verified by applying a gauge set to the minimum thickness found in the measurement.

2.9 The nominal wall thickness to be used in the design formula specified in paragraph 2.3 is the next wall thickness found in a commercial specification which is below the average of all the measurements taken.

2.10 Subject to paragraph 2.8 a person shall not use a wall thickness of a pipe that is

(a) more than 1.14 times the smallest measurement taken on a pipe less than 508 millimetres in the outside diameter; or

(b) more than 1.11 times the smallest measurement taken on a pipe of 508 millimetres or more in the outside diameter.

Design factor for steel pipe

2.11 Subject to this Schedule, the design factor required for the design formula under paragraph 2.3 shall be determined in accordance with the following table:

Class LocationDesign Factor (F)

1

2

3

4 0.72

0.60

0.50

0.40

2.12 A person shall use a design factor of 0.60 or less in the design formula specified in paragraph 2.3 for a steel pipe in a Class 1 location which

(a) crosses the right-of-way of an unimproved public road without a casing,

(b) crosses or makes a parallel encroachment on the right of way of either a hard surface road, a highway, a public street or a railway without casing,

(c) is supported by a vehicular, pedestrian, railway or pipeline bridge, or

(d) is used

(i) in a fabricated assembly, or

(ii) within five pipe diameters in any direction from the last fitting of a fabricated assembly other than a transition piece or an elbow used in place of a pipe bend which is not associated with fabricated assembly.

2.13 A person shall use a design factor of 0.50 or less in the design formula specified in paragraph 2.3 for a steel pipe in a Class 2 location for an uncased steel pipe which crosses the right-of-way of a hard surfaced road, a public highway, a public street or a railway.

2.14 A person shall use a design factor of 0.50 or less in the design formula in paragraph 2.3 for a

(a) steel pipe in a compressor station or measuring station; and

(b) steel pipe and a pipe riser on a platform located offshore or within inland navigable waters.

Longitudinal joint factor for steel pipe

2.15 The longitudinal joint factor required for the design formula in paragraph 2.3 shall be determined as indicated in the table below:

Specification   Pipe Class   Longitudinal Joint Factor (E)

ASTM A53/A53M   Seamless

Electric resistance welded

Furnace butt welded   1.00

1.00

0.60

ASTM A106   ASTM A106   1.00

ASTM A33/A 33/M   Seamless

Electric resistance welded   1.00

1.00

ASTM A381   Double submerged are welded   1.00

ASTM A671   Electric-fusion-welded   1.00

ASTM A672

ASTM A691   Electric-fusion-welded

Electric-fusion-welded   1.00

1.00

API 5 L Seamless

Electric resistance welded

Electric flash welded

Submerged are welded

Furnace butt welded 1.00

1.00

1.00

1.00

0.60

Other Pipe over 102 millimetres 0.80

Other Pipe 102 millimetres 0.60

If the type of longitudinal joint cannot be determined, the joint factor to be used shall not exceed that prescribed for “other”.

Temperature derating factor for steel pipe

2.16 (1) The temperature derating factor required for the design formula in paragraph 2.3 shall be determined as indicated in the table below:

Gas temperature in degrees Celsius (Fahrenheit) derating factor (T) Temperature derating factor (T)

121.11o C or less

148.89 o C

176.67 o C

204.44 o C

232.22 o C 1.000

0.967

0.933

0.900

0.867

(2) The derating factor for intermediate gas temperatures shall be determined by interpolation.

Design formula for plastic pipe

2.17 Subject to the limitations under paragraph 2.18 to 2.22, the design pressure for a plastic pipe is determined in accordance with either of the following formulae:

$$P = 2S \frac{t}{(D—t)} 0.32,$$

Or

$$P = \frac{2S}{(SDR-1)} 0.32$$

where:

P = design pressure, pascal guage.

S = for thermoplastic pipe, the Hydrostatic Design Basis determined in accordance with the listed specification at a temperature equal to 22.78°C, 37.788°C , 48.89°C or 60.00°C .

In the absence of a Hydrostatic Design Basis established at the specified temperature, the Hydrostatic Design Basis of a higher temperature may be used in determining the design pressure rating at the specified temperature by arithmetic interpolation using the procedure specified in Part A of the Fifteenth Schedule. For a reinforced thermosetting plastic pipe, 76 megapascals.

t = specified wall thickness, millimetre.

D = specified outside diameter, millimetre.

SDR = standard dimension ratio is the ratio of the average specified outside diameter of a pipe to the minimum specified wall thickness.

Design limitations for plastic pipe

2.18 Subject to this Schedule, the design pressure shall not exceed a gauge pressure of 689 kPa for a plastic pipe, which is used in

(a) a distribution system, or

(b) a Class 3 and 4 location.

2.19 A person shall not use a plastic pipe where the operating temperature on that pipe is likely to be

(a) — 28.89 °C and has a temperature rating consistent with that operating temperature, or

(b) above the following applicable temperatures

(i) for thermoplastic pipe, the temperature at which the Hydraulic Design Basis used in the design formula under paragraph 2.17 is determined; or

(ii) for a reinforced thermosetting plastic pipe of 65.56 °C.

2.20 The wall thickness for a thermoplastic pipe shall not be less than 2 millimetres.

2.21 The wall thickness for reinforced thermosetting plastic pipe shall not be less than that listed in the table below:

Normal size in millimeters	Minimum wall thickness in millimeters
51	2
76	2
102	2
152	2

2.22 Despite paragraph 2.18, the design pressure for a thermoplastic pipe may exceed a gauge pressure of 689 kPa if

(a) the design pressure does not exceed 862 kPa;

(b) the material is in accordance with the requirements specified in the Fifteenth Schedule;

(c) the pipe size is the nominal pipe size of 305 millimetres outside diameter or less; and.

(d) the design pressure is determined in accordance with the design formula for a plastic pipe provided under paragraph 2.17.

Design of copper pipe

2.23 A copper pipe used for the mains shall have a minimum wall thickness of 2 millimetres and shall be hard drawn.

2.24 A copper pipe used for a service line shall have a wall thickness not exceeding the measurement specified in the following table:

Standard size in millimeters	Nominal outside in millimeters		Wall thickness in millimetres
	Nominal	Tolerance	

13

16

19

25

32

38 16

19

22

29

35

41 102

107

114

127

140

1.52 0.09

0.09

0.10

0.10

0.11

0.11

2.25 A copper pipe used in the mains and a service line shall not be used at a pressure that exceeds 869 kPa gauge.

2.26 A copper pipe that does not have an internal corrosion resistant lining shall not be used to carry gas that has an average hydrogen sulphide content that exceeds 6.9 grains per cubic metre under standard conditions equivalent to 15.56°C and 101 kPa of gas.

Interpretation

2.27 In this Schedule, unless the context otherwise requires, "design factor" means a safety factor which accounts for the location of a pipe.

THIRD SCHEDULE

(Regulation 37)

DESIGN OF PIPE LINE COMPONENTS

Scope

3.1 This Schedule prescribes the minimum requirements for the design and installation of pipeline components and facilities and additionally prescribes requirements relating to the protection against accidental over pressuring.

General requirements

3.2 Each component of a pipeline must be able to withstand an operating pressure and other anticipated loading without the impairment of its serviceability with unit stress equivalent to that permitted for pipe of comparable material in the same location and kind of service.

3.3 Despite paragraph 3.2, if a design based on unit stress is impractical for a particular component, the design shall be based on a pressure rating established by the manufacturer after pressure testing that component or a prototype of that component.

Qualifying metallic components

3.4 Despite any requirement of this Schedule which incorporates by reference an edition of a standard listed in the Fifteenth Schedule, a metallic component manufactured in accordance with any other edition of that standard is qualified for use in this Schedule, if

(a) it can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength and tightness of the component; and

(b) the edition of the standard under which the component was manufactured has equal or more stringent requirements for the following

(i) pressure testing,

(ii) materials, and

(iii) pressure and temperature ratings.

Valves

3.5 Except for a cast iron valve and plastic valve, each valve shall meet the minimum requirements specified in Part A of the Fifteenth Schedule, or any other international standard that provides an equivalent performance level.

3.6 A person shall not use a valve under any operating condition that exceeds the applicable pressure-temperature ratings contained in the minimum requirements provided in Part A of the Fifteenth Schedule.

3.7 A person shall use cast iron and a plastic valve in accordance with the following conditions:

(a) the cast iron or plastic valve shall have a minimum service pressure rating for a temperature that is equivalent to or that exceeds the maximum service temperature,

(b) the cast iron or a plastic valve shall be tested as part of the following manufacturing processes:

(i) with the valve in a fully open position, the shell shall be tested to a pressure of not less than 1.5 times the maximum service pressure rating,

(ii) the seat shall be tested, after the shell test, to a pressure not exceeding 1.5 times the maximum service pressure rating,

(iii) the test pressure during the seat test shall be applied successively on each side of the closed valve with the opposite side open and there shall be no visible leaks, except in the case of a swing check valve, and

(iv) after the last pressure test is completed, the valve shall be operated at its maximum to demonstrate freedom from interference.

3.8 Each valve must be able to meet the anticipated operating conditions.

3.9 A person shall not use a valve that has a shell component that exceeds 80% of the pressure rating for a comparable steel valve at the listed temperature.

3.10 Despite paragraph 3.9, a person may use a valve with its shell components made of ductile iron up to 80% of the pressure rating for the comparable steel valve if

(a) the temperature-adjusted service pressure does not exceed 6.90 megapascals gauge; and

(b) welding is not used on any ductile iron component in the fabrication of the valve shell or other assembly.

3.11 A valve that has any pressure that contains a part made of ductile iron shall not be used in the gas pipe component of a compressor station.

Flanges and flange accessories

3.12 Except in the case of cast iron, each flange or flange accessory shall meet the minimum requirements of the standards specified in Part A of the Fifteenth Schedule, or its equivalent

3.13 A flange assembly shall be of a capacity to be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected while in service.

3.14 A flange on a flanged joint used in cast iron pipe shall

(a) be of the dimension, drilling, face and gasket design in compliance with the standards specified in Part A of the Fifteenth Schedule, and

(b) be cast integrally with the pipe, valve or fitting.

Standard fittings

3.15 The minimum metal thickness of a threaded fitting shall not be less than the applicable standards specified in this Schedule or other equivalent standards.

3.16 A steel butt-welding fitting shall have a pressure and temperature rating based on stress for pipe of the same equivalent material.

3.17 The actual bursting strength of a fitting shall

(a) be equivalent to the bursting strength of pipe and wall thickness of designated material and as determined by any prototype that has been tested to at least the pressure required for the pipeline to which it is being added, and

(b) have the equivalent pressure of the pipeline to which the fitting is being added.

Passage of internal inspection devices

3.18 Subject to paragraphs 3.19 to 3.22, a person shall design and construct each new transmission line and replacement of each pipeline, valve, fitting or other line component in a transmission line to accommodate the passage of any instrumented internal inspection device.

3.19 Paragraph 3.18 does not apply to the following:

(a) a manifold,

(b) a station piping at a compressor station, meter station, or regulator station,

(c) any piping associated with a storage facility, other than a continuous run of a transmission line between a compressor station and a storage facility,

(d) a cross-over,

(e) any size of pipe for which an instrumented internal inspection device is not commercially available,

(f) any transmission line that is operated in conjunction with a distribution system which is installed in a Class 4 location,

(g) an offshore transmission line, with the exception of a transmission line with an outside diameter of 273 millimetres or more that runs from platform to platform or platform to shore unless

(i) the platform space or configuration is incompatible with the launch or retrieving instrumented internal inspection device; or

(ii) the design includes a tap for a lateral connection, which the operator can demonstrate is based on investigation or experience, and that there is no reasonably practical alternative under the design in circumstances where the use of a tap is likely to obstruct the passage of an instrumented internal inspection device, and

(h) piping that, the Commission or its representative finds in a particular case would be impractical to design and construct to accommodate the passage of an instrumented internal inspection device.

3.20 An operator that encounters an emergency or construction time constraint other than an unforeseen construction problem is not required to construct a new or replacement segment of a transmission line in accordance with paragraph 3.18 if that operator documents why the impracticality prohibits compliance with paragraph 3.18.

3.21 The operator shall seek the approval of the Commission for the design and construction of a pipeline to accommodate the passage of any instrumented internal inspection device within fourteen days after discovering the emergency or construction problem.

3.22 If the Commission refuses to grant approval, the operator shall within one year of the refusal modify the relevant segment of the pipeline in accordance with the directive of the Commission to allow the passage of the instrumented internal inspection device.

Tapping

3.23 Each mechanical fitting used to make a hot tap, shall be of a design that is at least equivalent to the operating pressure of the pipeline.

3.24 Where a person taps a ductile pipe the extent of the use of a full thread engagement and the need for the use of an outside-sealing service connection, tapping saddle or other fixture shall be determined by service conditions.

3.25 Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole shall not be more than 25% of the nominal diameter of the pipe unless the pipe is reinforced, except that

(a) an existing tap may be used for replacement service, if it is free of any crack and has a good thread; and

(b) a 32 millimetre tap may be made in a 102 millimetre cast iron or ductile iron pipe, without reinforcement.

3.26 Despite paragraph 3.23 to 3.25, a person may use an unreinforced tap on a pipe of 152 millimetres or larger, in an area where climate, soil and service conditions may create unusual external stress on a cast iron pipe.

Components fabricated by welding

3.27 Except for a branch connection and assembly of a standard pipe and fitting joined by a circumferential weld, the design pressure of each component fabricated by welding of which the strength cannot be determined shall be established in accordance with the requirements provided in Part A of the Fifteenth Schedule.

3.28 A prefabricated unit that uses plate and longitudinal seams shall be designed, constructed and tested in accordance with the requirements provided in Part A of the Fifteenth Schedule, except for the following:

(a) a regularly manufactured butt-welding fitting;

(b) a pipe that has been produced and tested under a specification listed in Part A of the Fifteenth Schedule;

(c) a partial assembly like a split ring or collar; and

(d) a prefabricated unit that the manufacturer certifies has been tested to at least twice the maximum pressure to which it will be subjected under the anticipated operating condition.

3.29 A person shall not use an orange-peel bull plug or an orange-peel swage on a pipeline that is to operate at a hoop stress of 20% or more of the specified minimum yield strength of the pipe.

3.30 Except for a flat closure designed in accordance with the requirements provided in Part A of the Fifteenth Schedule, a person shall not use a flat closure or fish tail on a pipe that operates at 689 kPa gauge, or more, or that is more than 76 millimetres in nominal diameter.

Welded branch connection

3.31 A person shall design a welded branch connection for a pipe in the form of a single connection, or in a header or manifold as a series of connections, to ensure that the strength of the pipeline system is not reduced, taking into account

(a) the stresses in the remaining pipe wall due to the opening in the pipe or header;

(b) the shear stresses produced by the pressure acting on the area of the branch opening; and

(c) any external loading due to

(i) thermal movement,

(ii) weight, and

(iii) vibration.

Extruded outlet

3.32 An extruded outlet shall be suitable for an anticipated service condition and shall be at least equal to the design strength of the pipe and other fitting in the pipeline to which it is attached.

Flexibility

3.33 A person shall design a pipeline with enough flexibility to prevent

(a) thermal expansion or contraction from causing excessive stress in the pipe or its components,

(b) excessive bending or an unusual load at a joint, or

(c) any undesirable force or movement at a point of connection to the equipment, or at anchorage or guide point.

Supports and anchors

3.34 A pipeline and its associated equipment shall have enough anchor or support to

(a) prevent undue strain on connected equipment,

(b) resist any longitudinal force caused by a bend or offset in the pipe; and

(c) prevent or damp out excessive vibration.

3.35 An operator shall provide an exposed pipeline with sufficient support or anchor to protect any exposed pipe joint from the maximum end force caused by internal pressure and any additional force caused by temperature, expansion or contraction or by the weight of the pipe and its contents.

3.36 A person shall make a support or anchor on an exposed pipeline made of durable non-combustible material and design and install it as follows:

(a) the free expansion and contraction of the pipeline between any support or anchor shall be restricted,

(b) make provision for the service conditions involved, and

(c) ensure that the movement of the pipeline does not cause disengagement of the support equipment.

3.37 The support on an exposed pipeline operated at a stress level of 50% or more of the specified minimum yield strength shall

(a) not have a structural support welded directly onto the pipe,

(b) have a support that is provided by a member which completely encircles the pipe, and

(c) have a weld that is continuous and covers the entire circumference to cater for an encircling member welded to a pipe.

3.38 An underground pipeline which is connected to a relatively unyielding line or other fixed object shall have enough flexibility to provide for possible movement, or it must have an anchor which will limit the movement of the pipeline.

3.39 Except for an offshore pipeline, each underground pipeline which is being connected to a new branch shall have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

Location of compressor building

3.40 Each main compressor or building of a compressor station, except for a compressor building on a platform located offshore or within navigable waters shall be

(a) located on property within the control of the operator, and

(b) located far away from adjacent property which is not within the control of the operator, to minimise the possibility of the spread of fire to the compressor building from any structure on adjacent property.

Building on compressor station site

3.41 A building on a compressor station site shall be made of a non-combustible material if it contains either

(a) a pipe of more than 51millimetres in diameter which is carrying gas under pressure; or

(b) gas handling equipment other than gas utilisation equipment used for domestic purposes.

Exits

3.42 The operating floor of a main compressor building shall have at least two separate and unobstructed exits so as to provide a convenient and unobstructed passage of escape and each door on the operating floor of a main compressor building shall have

(a) a latch that can readily be opened from the inside without a key, or

(b) a swing latch embedded in an exterior wall and mounted to swing outward.

Fenced area

3.43 A fence around a compressor station shall have at least two gates to provide

(a) a convenient opportunity for escape to a place of safety, or

(b) a facility which affords a convenient exit from the area.

3.44 Each gate located within 60.96 metres of any compressor plant building shall be designed to

(a) open outward, or

(b) open from the inside without a key when occupied.

Electrical facilities

3.45 A person who installs any electrical equipment and wiring in a compressor station shall comply with Regulations in respect of wiring.

Liquid removal at compressor stations

3.46 Where entrained vapour in gas may liquefy under the anticipated pressure and temperature condition, the compressor must be protected against the introduction of the liquid in any quantity which could cause damage.

3.47 Each liquid separator used to remove entrained liquid at a compressor station shall

(a) have a manually operable means of removing these liquids; or

(b) have either

(i) automatic liquid removal facilities,

(ii) an automatic compressor shutdown device, or

(iii) a high liquid level alarm

where slugs of liquid could be carried into the compressors;

and

(c) be manufactured in accordance with the requirements specified in the Fifteenth Schedule, except that a liquid separator constructed of pipe and fittings without internal welding shall be fabricated with a design factor of 0.4, or less.

Emergency shutdown of compressor stations

3.48 Except for an unattended field compressor station of 746.70 kilowatts or less, each compressor station shall have an emergency shutdown system that

(a) is able to block gas out of the station and blow down the station piping,

(b) can discharge gas from the blowdown piping at a location where the gas will not create a hazard,

(c) can provide a means for the shutdown of a gas compressing equipment, gas fire and electrical facility in the vicinity of a gas header and in the compressor building, except that

(i) any electrical circuit which supplies emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas header shall remain energised, and

(ii) any electrical circuit required to protect equipment from damage shall remain energised,

(d) is operable from at least two locations, each of which shall be

(i) outside the gas area,

(ii) near the exit gates, if the station is fenced, or near an emergency exit, if not fenced; and.

(iii) not more than 152 metres from the boundaries of the station.

3.49 If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system shall be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

3.50 The emergency shutdown system on a platform located offshore or within inland navigable waters shall be designed and installed to actuate automatically by each of the following events:

(a) in the case of an unattended compressor station.

(i) when the gas pressure increases to 15% above the maximum allowable operating pressure, or

(ii) when an uncontrolled fire occurs on the platform; and

(b) in the case of a compressor station building

(i) when an uncontrolled fire occurs in the building, or

(ii) when the concentration of gas in the air increases to 50% or more of the lower explosive limit in a building which has a source of ignition.

3.51 For the purpose of paragraph 3.50 (b) (ii), an electrical facility, which meets the requirements in respect of wiring, is not a source of ignition.

Pressure limiting devices of compressor stations

3.52 A compressor station shall have a pressure relief or other suitable protective device of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10%.

3.53 Each vent line which exhausts the pressure relief valve of a compressor station shall extend to a location where the gas may be discharged without hazard.

Additional safety equipment for compressor stations

3.54 A compressor station shall have adequate fire protection facilities and where fire pumps are a part of these facilities, their operation shall not be affected by the emergency shutdown system.

3.55 A compressor station prime mover, other than an electrical induction or synchronous motor, shall have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

3.56 A compressor unit in a compressor station must have a shutdown or alarm device which can operate in the event of inadequate cooling or lubrication of the unit.

3.57 A compressor station of a gas station engine which operates with a pressure gas injection shall be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

3.58 Each muffler for a gas engine in a compressor station shall have a vent slot or a hole in the baffles of each compartment to prevent gas from being trapped in the muffler.

Ventilation of compressor stations

3.59 A compressor station building shall be ventilated to ensure that the employees concerned are not endangered by the accumulation of gas in any room, sump, pit, or other enclosed place.

Pipe-type and bottle-type holders

3.60 A person that uses a pipe-type or bottle-type holder shall ensure that it is of a design that can prevent the accumulation of liquid in the holder, the connecting pipe or in auxiliary equipment, which might cause corrosion or interfere with the safe operation of the holder.

3.61 A pipe-type or bottle-type holder shall have minimum clearance from any other holder in accordance with the following formula:

C = (D x P x F)/48.33) (C= (3D x P x F /1,000))

where

C = minimum clearance between pipe containers or bottles in millimetre.

D = outside diameter of pipe containers or bottles in millimetre.

P = maximum allowable operating pressure, pascal gauge.

F = design factor as set forth in paragraph 2.11 to 2.14 of the Second Schedule.

Additional provisions for bottle-type holders

3.62 A bottle-type holder shall be

(a) located on a site surrounded entirely by fencing which prevents access by unauthorised persons and with minimum clearance from the fence as follows

Maximum allowable operating pressure	Minimum clearance in metres
Less than 7 megapascals gauge	
7 megapascals gauge or more 8	

30

(b) designed using the design factors set forth in paragraphs 2.11 to 2.14 of the Second Schedule; and

(c) buried with a minimum cover in accordance with paragraphs 6.36 to 6.40 of the Sixth Schedule.

3.63 A bottle-type holder that is manufactured from steel and which is not weldable under field conditions shall meet the following requirements:

(a) the chemical and tensile requirements for the various grades of steel specified in Part A of the Fifteenth Schedule, if that bottle type holder is made from alloy steel,

(b) the actual yield-tensile ratio of steel shall not exceed the design factor of 0.85,

(c) the welding shall not be performed on the holder after it has been heated treated or stress relieved, except that a copper wire may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localised thermit welding process is used,

(d) the holder shall be given a mill hydrostatic test at a pressure which produces a hoop stress of at least 85% of the specified minimum yield strength, and

(e) the holder, connection pipe, and any component shall be leak tested after installation in compliance with the Ninth Schedule.

Transmission line valves

3.64 A transmission line other than an offshore segment, shall have sectionalising block valves spaced as follows:

(a) each point on the pipeline in a Class 4 location shall be within 4 kilometres of a valve,

(b) each point on the pipeline in a Class 3 location shall be within 6 kilometres of a valve,

(c) each point on the pipeline in a Class 2 location shall be within 12 kilometres of a valve, and

(d) each point on the pipeline in a Class 1 location shall be within 16 kilometres of a valve

unless the Commission in a particular case determines that alternative spacing may provide an equivalent level of safety.

3.65 A person who fixes a sectionalising block valve on a transmission line, other than an offshore segment, shall ensure that

(a) the valve and the operating device to open or close the valve is readily accessible and protected from tampering and damage, and

(b) the valve is supported to prevent settling of the valve or movement of the pipe to which it is attached.

3.66 Without limiting paragraph 3.65

(a) a section of the transmission line other than an offshore segment between the main line valves shall have a blow-down valve with sufficient capacity to enable the transmission line to be blown down as rapidly as practicable,

(b) each blow down discharge shall be located in a manner that will permit the

(i) blowing of gas into the atmosphere without hazard, and

(ii) gas to be directed away from an electrical conductor if the transmission line is adjacent to an overhead electrical line.

3.67 An offshore transmission line shall be equipped with valves or any other component to shut off the flow of gas to an offshore platform on an emergency.

Distribution line valves

3.68 A high-pressure distribution system shall have valves spaced in a manner that can reduce the time to shut down a section of the mains in an emergency.

3.69 Valve spacing shall be determined by the operating pressure, the size of the mains and local physical conditions.

3.70 A regulating station that controls the flow or pressure of gas in a distribution system shall have a valve installed on the inlet piping at a distance from the regulating station to permit the operation of the valve during an emergency.

3.71 Where a person installs a valve on the mainline for the purpose of operation during an emergency, that person shall ensure that

(a) the valve is placed in a readily accessible location so as to facilitate its operation in an emergency,

(b) the operating mechanism is readily accessible, and

(c) the box or enclosure is installed so as to avoid transmitting any external load to the mainline if the valve is installed in a buried box or enclosure.

Structural design requirements of vaults

3.72 A person who designs an underground vault or pit for a valve, a pressure relieving, pressure limiting, or pressure regulating station, shall ensure that

(a) it has the capacity to meet the loads imposed on it,

(b) the installed equipment is protected, and

(c) there is enough working space so that all of the equipment required in the vault or pit can be properly installed, operated and maintained.

3.73 An operator shall ensure that each pipe that enters a regulator vault or pit is made of steel and is of a size equivalent to 254 millimetres or less, except that a control or gauge piping may be made of copper.

3.74 Where a pipe extends through the vault or pit structure, provision shall be made to prevent the passage of gas or liquid through the opening and to avert any strain in the pipe.

Accessibility of vaults

3.75 A vault shall be located in an accessible location and, as far as practicable, away from

(a) a street intersection or point where traffic is heavy or dense,

(b) any point of minimum elevation, catch basin, or place where the access cover will be in the course of surface waters, and

(c) water, electricity, steam or other facilities.

Sealing, venting and ventilation of vaults

3.76 An underground vault or closed top pit containing a pressure regulating station, a pressure reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows

(a) when the internal volume exceeds 5.66 cubic metres

(i) the vault or pit shall be ventilated with two ducts, each with at least the ventilating effect of a pipe 102 millimetres in diameter;

(ii) the ventilation shall be enough to minimise the formation of combustible atmosphere in the vault or pit,

(iii) the ducts shall be high enough and above grade to disperse any gas-air mixture which might be discharged, and

(b) when the internal volume is more than 2.12 cubic metres but less than 5.66 cubic metres

(i) the opening of a vault or pit that is sealed, shall have a tight fitting cover without open holes through which an explosive mixture may be ignited with a means for testing the internal atmosphere before removing the cover,

(ii) if a vault or pit is vented, there must be a means to prevent any external source of ignition from reaching the vault atmosphere, or

(iii) paragraph (a) or (c) shall apply, if the vault or pit is ventilated, and

(c) no additional ventilation is required if a vault or pit to which paragraphs (a) and (b) apply, is ventilated by

(i) any opening in the cover or grating, or

(ii) the ratio of the internal volume in cubic metres to the effective ventilating area of the cover or grating in square metres is less than 20:1.

Drainage and waterproofing of vaults

3.77 A person shall design a vault to minimise the entry of water.

3.78 A person shall not connect a vault that contains gas piping to an underground structure.

3.79 A person that uses electrical equipment in a vault shall ensure that it meets the requirements in respect of wiring specified in the Electrical Wiring Regulations, 2012 (L.I. 2008).

Design pressure of plastic fittings

3.80 A thermosetting fitting for plastic pipe shall conform to the standards specified in Part A of the Fifteenth Schedule.

Valve installation in plastic pipe

3.81 A person who intends to install a valve in a plastic pipe, shall ensure that the design is amenable to the protection of the plastic material of the pipe against any excessive torsional or shearing load when the valve or shutoff is operated and is protected from any other secondary stress which is likely to be exerted through the valve or its enclosure.

Protection against accidental over pressuring

General requirements

3.82 Subject to paragraphs 3.84 and 3.86, each pipeline which is connected to a gas source shall have a pressure relieving or pressure limiting device which meets the requirements of paragraph 3.88 to 3.91 to enable the maximum allowable operating pressure exceed its normal level in case of pressure control failure or any other type of failure.

Additional requirements for distribution systems

3.83 A distribution system, which is supplied from a source of gas, which is at a higher pressure than the maximum allowable operating pressure, shall

(a) have a pressure regulation device that is capable of meeting the pressure, load and other service condition which would be experienced in the normal operation of the system, and that could be activated in the event of failure of some portion of the system, and

(b) be designed so as to prevent accidental over pressuring.

Control of the pressure of gas delivered from high-pressure distribution systems

3.84 A pressure limiting device is not required if the maximum actual operating pressure of the distribution system is 414 kPa gauge, or less and has a service regulator with the following characteristics:

(a) a regulator capable of reducing the distribution line pressure to a pressure recommended for a household appliance,

(b) a single port valve with proper orifice for the maximum gas pressure at the regulator inlet,

(c) a valve seat made of resilient material designed to withstand abrasion of the gas impurities in the gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port,

(d) a pipe connection to the regulator not exceeding 51 millimetres in diameter,

(e) a regulator which under normal operating conditions, is able to regulate the downstream pressure within the necessary limit of accuracy and to limit the build-up of pressure under a no-flow condition to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilisation equipment, and

(f) a self-contained service regulator with no external static or control line.

3.85 If the maximum actual operating pressure of the distribution system is 414 kPa gauge, or less, and a service regulator that does not have each characteristic listed in paragraph 3.81 is used, or if the gas contains any material which can seriously interfere with the operation of a service regulator, the distribution system shall have suitable protective devices to prevent unsafe pressuring of a customer's appliances if the service regulator fails.

3.86 If the maximum actual operating pressure of the distribution system exceeds 414 kPa gauge, one of the following methods shall be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(a) a service regulator that has the characteristics listed in paragraph 3.84 and another regulator located upstream from the service regulator, if

(i) the upstream regulator shall not be set to maintain a pressure higher than 414 kPa gauge,

(ii) the device is installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 414 kPa gauge or less in case the upstream regulator fails to function properly,

(iii) the device installed is either a relief valve or an automatic shutoff which shuts, if the pressure on the inlet of the service regulator exceeds the set pressure of 414 kPa gauge or less, and remains closed until manually reset,

(b) a service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer

(c) a service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open to prevent the pressure of gas going to the customer from exceeding a maximum safe value where

(i) the relief valve is not built into the service regulator or is installed as a separate unit downstream from the service regulator;

(ii) this combination may be used alone only where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, or shall not be used where the inlet pressure on the service regulator exceeds 682 kPa gauge;

(iii) the methods in sub-paragraphs (a) or (b) are used for higher inlet pressures; or

(d) a service regulator and an automatic shutoff device that closes with a rise in pressure downstream from the regulator remains closed until manually reset.

Requirements for design of pressure relief and limiting devices

3.87 A person shall not use a pressure relief or pressure limiting device other than a rupture disk unless it

(a) is constructed with material that will not impair the operation of the device through corrosion,

(b) has a valve and valve seat designed not to stick in a position that will make the device inoperative,

(c) is designed and installed so that it can be readily operated to

(i) determine if the valve is free,

(ii) to be tested to determine the pressure at which it will operate, and

(iii) be tested for leakage when in the closed position,

(d) has support made of non-combustible material,

(e) has a discharge stack, vent or outlet port designed to prevent accumulation of water, located where gas can be discharged into the atmosphere without undue hazard,

(f) is designed and installed so that

(i) the size of any opening, pipe or fitting located between the system to be protected and the pressure relieving device, or

(ii) the size of the vent line is adequate to prevent hammering of the valve and the impairment of relief capacity,

(g) is designed and installed to prevent any incident such as an explosion in a vault or damage by a vehicle from affecting the operation of the overpressure protective device and the district regulating station, where it is installed at a district regulating station, or

(h) is designed to prevent the unauthorised operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative, except for a valve which will isolate the system under protection from its source of pressure.

Required capacity of pressure relieving and limiting stations

3.88 Each pressure relief station or pressure limiting station or a group of those stations installed to protect a pipeline shall have enough capacity to operate.

3.89 A person who sets in operation the pressure relief station referred to in paragraph 3.88 shall ensure that

(a) in a low pressure distribution system, the pressure does not cause the unsafe operation of any connected and properly adjusted gas utilisation equipment,

(b) in a pipeline other than a low pressure distribution system

(i) the pressure would not exceed 10% more than the maximum allowable operating pressure plus 10% or the pressure that produces a hoop stress of 75% of the specified minimum yield strength, whichever is lower, if the maximum allowable operating pressure is 414 kPa gauge or more,

(ii) the pressure would not exceed the maximum allowable operating pressure by 414 kPa guage, if the maximum allowable operating pressure is 83 kPa gauge or more, but less than 414 kPa gauge, or

(iii) the pressure shall not exceed 50% or more than the maximum allowable operating pressure, if the maximum allowable operating pressure is less than 83 kPa guage.

3.90 Where more than one pressure regulating or pressure compressor station feeds into a pipeline, a relief valve or other protective device shall be installed at each station to ensure that

(a) the complete failure of the largest capacity regulator or compressor, or

(b) any single run of a lesser capacity regulator or compressor in that station,

does not impose pressure on any part of the pipeline or distribution system in excess of what it was designed for or against which it was protected.

3.91 A retief valve or other pressure limiting device with a capacity to limit the maximum pressure in the main to pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilisation equipment, shall be installed at or near each regulating station in a low-pressure distribution system.

Instrument control and sampling pipe and components

Materials and design

3.92 Any material that is used for a pipe or a component of a pipe shall be of a design to meet the particular conditions of service to include the following:

(a) each take off connection and attaching boss, fitting or adapter shall

(i) be made of suitable material,

(ii) be of a capacity to withstand the maximum service pressure and temperature of the pipe equipment to which it is attached, and

(iii) be able to withstand any stress without failure by fatigue,

(b) a shut off valve other than a takeoff line that can be isolated from a source of pressure by other valving shall be installed in each takeoff line as near as practicable to the point of takeoff,

(c) a blowdown valve shall be installed where necessary,

(d) brass or copper material shall not be used for metal temperatures that exceed 204.44°C ,

(e) any pipe or component that contains a liquid shall be protected by heating or other means from damage due to freezing,

(f) any pipe or a component in which liquid may accumulate shall have a drain or drip,

(g) any pipe or component subject to clogging from solid or deposit shall have a suitable connection for cleaning,

(h) the arrangement of a pipe, component, or support shall provide safety under anticipated operating stress,

(i) each joint between the sections of a pipe, and between a pipe and a valve or fitting, shall

(i) be fixed in a manner suitable for the anticipated pressure and temperature conditions,

(ii) allow for expansion by providing flexibility with the system itself,

(iii) not have a slip type expansion joint, and

(j) each control line shall be protected from any anticipated cause of damage and shall be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

3.93 Paragraph 3.92 is applicable to the following:

(a) the design of an instrument,

(b) the control of a pipeline, and

(c) a sampling pipe and its components.

3.94 Paragraph 3.93 does not apply to a permanently closed system including a fluid-filled temperature-responsive device.

Interpretation

3.95 In this Schedule, unless the context otherwise requires,

“blowdown discharge” means the release of unwanted gas into the atmosphere;

"entrained liquid" means any liquid trapped or suspended in a gaseous fluid;

“prime mover” means a device that converts potential energy into mechanical motion;

“pit” means an excavation or cavity in the ground that contains natural gas pipeline equipment; and

“sump” means a low space that collects liquid like water or oil.

FOURTH SCHEDULE

(Regulations 13 and 37)

WELDING

Qualification tests for welders for low stress level pipe

4.1 The basic, additional and periodic test requirements for welders for low stress level pipes are provided for in the Seventeenth Schedule.

Limitations on welder

4.2 A welder whose qualification is limited to non-destructive testing shall not weld a compressor station pipe or its component.

4.3 A welder shall not carry out a particular welding process unless that welder has been engaged in that welding process within the preceding six months;

4.4 A welder qualified under paragraph 4.1 shall not weld on a pipe to be operated at a pressure which produces a hoop stress of 20% or more of the specified minimum yield strength unless;

(a) within the preceding six months that welder has had one weld tested, found acceptable in accordance with the standards specified in Part A of the Fifteenth Schedule, or

(b) that welder maintains an ongoing qualification status by performing welds that are tested at least once each year, but at intervals not exceeding seven months.

4.5 A welder shall not weld on a pipe to be operated at a pressure that produces a hoop stress of less than 20% of the specified minimum yield strength unless that welder is tested in accordance with paragraph 4.4.

4.6 A welder qualified under paragraph 4.1 shall not weld unless

(a) that welder has performed an acceptance test weld in accordance with paragraph 4.1 within the preceding fifteen months but at least once in each year;

(b) that welder has had a production weld cut, tested and found acceptable in accordance with the qualifying test within the preceding seven months, but at least twice in each year, or

(c) two sample welds have been tested and found compliant with the test requirements specified in paragraph 4.1, if that welder works only on a service line of 51millimetres or smaller in diameter.

Miter joints

4.7 A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of

(a) 30% or more of the specified minimum yield strength may not deflect the pipe more than 3°,

(b) less than 30% but more than 10% of specified minimum yield strength may not deflect the pipe more than 12.5°, and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint, or

(c) 10% or less of the specified minimum yield strength may not deflect the pipe more than 90°.

Preparation for welding

4.8 A welder shall

(a) ensure that the welding surface to be used for welding is clean and free of any material likely to be detrimental to the weld,

(b) align a pipe or its component to provide the most favourable condition for depositing the root bead before commencement of welding.

4.9 A welder shall preserve the alignment while the root bead is being deposited.

Inspection and test of weld

4.10 The visual inspection of welding shall be conducted by an individual who is qualified and has appropriate training and experience to ensure that

(a) the welding is performed in accordance with the welding procedure; and

(b) the weld meets the requirements of paragraph 4.13.

4.11 Subject to paragraph 4.13, the weld on a pipeline to be operated at a pressure that produces a hoop stress of 20% or more of the specified minimum yield strength shall be non-destructively tested in accordance with paragraph 4.14 to 4.19.

4.12 A weld that is visually inspected and approved by a qualified welding inspector is not required to be non-destructively tested if

(a) the pipe has a nominal diameter of less than 152 millimetres; or

(b) the pipe is to be operated at a pressure which produces a hoop stress of less than 40% of the specified minimum yield strength and that weld is so limited that the non-destructive testing is impractical.

4.13 Without limiting paragraph 4.11, if a girth weld is unacceptable by the standards specified in Part A of the Fifteenth Schedule for a reason other than a crack, the acceptability of the weld shall be further determined in accordance with the specifications of the correlative standard specified in Part A of the Fifteenth Schedule.

Non-destructive testing

4.14 The non-destructive testing of a weld shall be performed by a process, other than trepanning, to clearly indicate any defect that may affect the integrity of the weld.

4.15 Non-destructive testing of a weld shall be performed

(a) in accordance with established procedures of the operator; and

(b) by a person who is qualified to use the equipment required for testing.

4.16 The operator shall establish procedures for the proper interpretation of each non-destructive test of a weld to ensure the acceptability of the weld under paragraph 4.10.

4.17 When non-destructive testing is required under paragraph 4.11, the following percentages of each day's field butt welds, selected at random by the operator, shall be non-destructively tested over their entire circumference

(a) in a Class 1 location, except offshore, at least 10 %,

(b) in a Class 2 location, at least 15 %,

(c) in Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within rail road or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100% if it is practicable, in which case at least 90 %, if it is impractical, and

(d) at pipeline tie-ins, including tie-ins of replacement sections, at 100%.

4.18 Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day shall be non-destructively tested, when non-destructive testing is required under paragraph 4.11.

4.19 When non-destructive testing is required under paragraph 4.11, the operator shall retain, for the life of the pipeline, a record that indicates milepost, engineering station, or by geographic feature

(a) the number of girth welds made,

(b) the number of girth welds non-destructively tested,

(c) the number of girth welds rejected, and (e)sic the disposition of the girth welds rejected.

Repair or removal of defects

4.20 A weld shall be removed or repaired if it

(a) is unacceptable, subject to paragraph 4.13, or

(b) has a crack that is more than 8% of the weld length.

4.21 Despite paragraph 4.20(b), a weld on an offshore pipeline that is being installed from a pipeline vessel is not required to be removed.

4.22 Each weld that is repaired shall have

(a) the defect removed down to sound metal,

(b) its segment due for repair preheated if an existing condition is likely to have an adverse effect on the quality of the weld repair, and

(c) the segment of the weld that was repaired inspected by the Commission to ensure its acceptability.

4.23 The repair of a crack or any defect in a previously repaired area shall be carried out in accordance with the weld repair procedures specified in Part A of the Fifteenth Schedule

4.24 A repair procedure shall provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are complied with on completion of the final weld repair.

Interpretation

4.25 In this Schedule, unless the context otherwise requires,

“crotch” means a region of the angle formed by the junction of two parts of a pipeline;

“miter joint” means a joint made by beveling each of two parts to be joined, usually at a 45° angle, to form a corner, at a 90° angle; and

“trepanning” is a process of removing surface material on a weld.

FIFTH SCHEDULE

(Regulations 15 and 37)

JOINING OF MATERIAL OTHER THAN BY WELDING

Scope

5.1 This Schedule prescribes the minimum requirements for joining materials in pipelines, other than by welding, except joining during the manufacture of a pipe or pipeline component.

General requirements

5.2 A pipeline shall be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

Cast iron pipe

5.3 Each caulked bell and spigot joint in a cast iron pipe shall be sealed with mechanical leak clamps.

5.4 Each mechanical joint in a cast iron pipe shall have a gasket

(a) made of a resilient material as the sealing medium, and

(b) which shall be suitably confined and retained under compression by a separate gland or follower ring.

5.5 A cast iron pipe shall not be joined by

(a) a threaded joint, or

(b) brazing.

Ductile iron pipe

5.6 A ductile iron pipe shall not be joined by

(a) a threaded joint; or

(b) brazing.

Copper pipe

5.7 A person shall not thread a copper pipe.

5.8 Despite paragraph 5.6, a person may thread a copper pipe if it is to be used for joining a screw fitting or valve and it has a wall thickness equivalent to the standard specified in Part A of the Fifteenth Schedule.

Plastic pipe

5.9 A person shall not join a plastic pipe by a threaded joint or a miter joint.

5.10 A plastic pipe, which is joined by solvent cement, adhesive, or heat fusion, shall not be disturbed until it has been properly set.

Solvent cement joints

5.11 A person who uses a solvent cement joint on a plastic pipe shall ensure compliance with the following:

(a) the mating surfaces of the joint shall be clean, dry, and free of material which can be detrimental to the joint,

(b) the solvent cement shall conform to the standard specified in Part A of the Fifteenth Schedule, and

(c) the joint shall not be heated to accelerate the setting of the cement.

Heat-fusion joint

5.12 A person who uses a heat-fusion joint on a plastic pipe shall comply with the following conditions:

(a) a butt heat-fusion joint shall be joined by a device which holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens,

(b) a socket heat-fusion joint shall be joined by a device which heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature,

(c) an electrofusion joint shall be joined utilising

(i) the equipment and technique of a fittings manufacturer, or

(ii) the equipment and technique used for joining, by testing a joint in accordance with paragraph 5.17(a)(iii), to be at least equivalent to those of the fittings manufacturer, and

(d) heat shall not be applied with a torch or other open flame.

Adhesive joints

5.13 A person who uses an adhesive joint on a plastic pipe shall

(a) comply with the standard specified in Part A of the Fifteenth Schedule, and

(b) ensure that the material used is compatible with the adhesive.

Mechanical joints

5.14 The gasket material in the coupling of each compression type mechanical joint on a plastic pipe shall be compatible with the plastic.

5.15 A rigid internal tubular stiffener, other than a split tubular stiffener, shall be used in conjunction with the coupling of each compression type of mechanical joint on a plastic pipe.

Qualifying joining procedures for plastic pipe

Heat fusion, solvent cement and adhesive joints

5.16 The operator shall establish written procedures for making plastic pipe joints by heat fusion, solvent cement and adhesive joints.

5.17 The procedure shall be qualified by the subjection of specimen joints to the following tests:

(a) the burst test requirements of

(i) a sustained pressure, a minimum hydrostatic burst or a sustained static pressure in the case of thermoplastic pipe in accordance with the standard specified in Part A of the Fifteenth Schedule, or

(ii) a minimum hydrostatic burst pressure or a sustained static pressure in the case of a thermosetting plastic pipe in accordance with the standard specified in Part A of the Fifteenth Schedule, or

(iii) minimum hydraulic burst pressure, sustained pressure, tensile strength or a joint integrity in the case of an electrofusion fitting for a polyethylene pipe and tubing in accordance with the standard specified in Part A of the Fifteenth Schedule,

(b) for the procedure intended for a lateral pipe connection, subject to a specimen joint made from a pipe section joined at right angles according to the procedure, to a force on the lateral pipe until failure initiated outside the joint area occurs in the specimen, and

(c) for the procedure intended for a non-lateral pipe connection, follow the tensile test requirements of the standard specified in Part A of the Fifteenth Schedule, except that the test shall be conducted at an ambient temperature and humidity.

5.18 Despite subparagraph 5.17(c), if the specimen joint elongates at a level of 25% and above, or failure initiates outside the joint area, the procedure qualifies for use.

Procedure for making plastic mechanical joint

5.19 A procedure that is established for the construction of a mechanical plastic pipe joint designed to withstand any tensile force, shall be qualified by subjecting five specimen joints made in accordance with the procedure to the following tensile test:

(a) the use of an apparatus for a test of the standard specified in Part A of the Fifteenth Schedule, except for conditioning,

(b) the specimen shall be of a length such that the distance between the grips of the apparatus and the end stiffener does not affect the joint strength,

(c) the speed testing of 5 millimetres per minute, plus or minus 25%,

(d) the use of a pipe specimen of not more than 102 millimetres in diameter if the pipe yields to an elongation of not less than 25% or failure initiates outside the joint area,

(e) the use of a pipe specimen of 102 millimetres or more in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or exceeding the maximum thermal stress that would be produced by a temperature change of 37.78° C or until the pipe is pulled from the fitting, except that if the pipe is pulled from the fitting, the lowest value of the five test results or the manufacturer's rating shall be used in the design calculations for stress, and

(f) the retesting of using new pipe of each specimen that fails at the grips.

5.20 The results obtained under paragraph 5.19 shall apply only to the specific outside diameter, and material of the pipe tested.

5.21 A copy of each procedure that is used for joining a plastic pipe shall be made available to any person who makes and inspects joints.

Person qualified to make plastic pipe joint

5.22 A person shall not make a plastic pipe joint unless that person

(a) has undergone the appropriate training and acquired experience in the application of the procedure, and

(b) can make a specimen joint from a pipe section joined according to the procedure for the inspection and test set specified in paragraph 5.24.

5.23 A person is qualified to make a plastic pipe joint if that person has

(a) undergone the appropriate training,

(b) passed the

(i) inspection test for making a specimen joint, and

(ii) test referred to in paragraph 5.24, and

(c) obtained adequate experience in the use of the procedure.

5.24 The specimen joint shall

(a) be visually examined during and after the assembly or joining and shall have the same appearance as a joint or photograph of a joint which is acceptable under the procedure, and

(b) in the case of a heat fusion, solvent cement or adhesive joint

(i) be tested under any one of the test methods specified under paragraph 5.17 that is applicable to the type of joint and material being tested,

(ii) be examined by ultrasonic inspection and be found not to contain any flaw that can cause failure, or

(iii) be cut into at least three longitudinal straps, each of which shall be visually examined and found not to contain any void, discontinuity on the cut surface of the joint area, or deformed by bending, torque, or impact, and if failure occurs, the specimen joint shall not initiate in the joint area.

5.25 A person shall be subject to a qualification under the applicable procedure, if during the preceding twelve month period that person

(a) has not made any joint under the procedure; or

(b) has made three joints or 3% of joints, whichever is greater, under the procedure and the joints are unacceptable under paragraph 9.22 to 9.25 of the Ninth Schedule.

5.26 Each operator shall establish a method to determine that each person who makes a joint in a plastic pipeline in the operator's system is qualified in accordance with this Schedule.

Inspection of plastic pipe joint

5.27 A person shall not carry out the inspection of a joint in plastic pipe as required under paragraph 5.2 to 5.17 and paragraph 5.23, unless that person is qualified and experienced to evaluate the acceptability of a plastic pipe joint made under the applicable joining procedure.

Interpretation

5.28 In this Schedule, unless the context otherwise requires,

“gasket” means a shaped piece or ring of rubber or other material used to seal the junction between two surfaces;

“gland” means a sleeve used to produce a seal around the pipe;

“spigot joint” means a connection between two sections of pipe with the straight spigot end of one section inserted in the flared end of the adjoining section and with the joint sealed by a caulking compound or with a compressible ring;

“threaded joint” means a joining of parts by means of threads; and

“torque” means the tendency of a force to rotate an object about an axis

SIXTH SCHEDULE

(Regulations 16 and 17)

CONSTRUCTION REQUIREMENTS FOR TRANSMISSION LINES AND MAINS

Scope

6.1 This Schedule prescribes minimum requirements for the construction of transmission lines and mains.

Repair of steel pipe

6.2 Any imperfection or damage which impairs the serviceability of a steel pipe shall be repaired or removed except that where the repair is made by grinding, the remaining wall thickness shall be at least equal to

(a) the minimum thickness required by the tolerance in the specification to which the pipe was manufactured, or

(b) the nominal wall thickness required for the design pressure of the pipeline.

6.3 Except where a dent is repaired by a method that a reliable engineering test and analysis can permanently restore the serviceability of the pipe involved, the following dents shall be removed from the steel pipe to be operated at a pressure that produces a hoop stress of 20% or more of the specified minimum yield strength:

(a) a dent which contains a stress concentrator such as a scratch, gouge, groove or arc burn,

(b) a dent that affects the longitudinal weld or a circumferential weld of a pipe,

(c) a dent which has a depth

(i) exceeding 7millimetres in pipe of 324 millimetres or less in outer diameter, or

(ii) of more than 2% of the nominal pipe diameter in pipe of over 324 millimetres in outer diameter in a pipe to be operated at a pressure that produces a hoop stress of 40% or more of the specified minimum yield length.

6.4 For the purposes of paragraph 6.3

(a) a "dent" means a depression which produces a gross disturbance in the curvature or the pipe wall without reducing the pipe wall thickness, and

(b) the depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

6.5 A person who operates a burn on steel pipe at a pressure that produces a hoop stress of 40% or more, of the specified minimum yield strength, shall repair or remove it, except that if the repair is made by grinding, the arc burn shall be completely removed and the remaining wall thickness shall be equal to

(a) the minimum wall thickness required by the tolerance in the specification to which the pipe was manufactured, or

(b) the nominal wall thickness required for the design pressure of the pipeline.

6.6 A gouge, groove, arc burn or dent shall not be repaired by insert patching or by pounding out.

6.7 Each gouge, groove, arc burn or dent which is to be removed from a length of pipe shall be removed by cutting out the damaged portion as a cylinder.

Repair of plastic pipe

6.8 Where an imperfection or damage is likely to impair the serviceability of a plastic pipe, it shall be repaired or removed.

Bends and elbows

6.9 A person who makes a bend in a steel pipe, other than a wrinkle bend made in accordance with paragraphs 6.12 and 6.13, shall comply with the following conditions:

(a) a bend shall not impair the serviceability of the pipe,

(b) each bend shall have a smooth contour and be free from buckling, a crack or any other mechanical damage,

(c) in the case of a pipe that contains a longitudinal weld, the longitudinal weld shall be as near as practicable to the neutral axis of the bend unless

(i) the bend is made with an internal bending mandrel, or

(ii) the pipe is 305 millimetres or less in outer diameter or has a diameter to wall thickness ratio of less than 70.

6.10 Each circumferential weld of steel pipe, which is located where the stress during bending causes a permanent deformation in the pipe shall be non-destructively tested before or after the bending process.

6.11 A wrought-steel welding elbow and transverse segment of an elbow shall not be used for any change in direction on steel pipe which is 51 millimetres or more in diameter unless the arc length, as measured along the crotch, is at least 25 millimetres.

Wrinkle bends in steel pipe

6.12 A wrinkle bend shall not be made on a steel pipe to be operated at a pressure that produces a hoop stress of 30%, or more of the specified minimum yield strength.

6.13 Each wrinkle bend on a steel pipe shall comply with the following:

(a) the bend shall not have any sharp kink;

(b) the wrinkles shall be at a distance of at least one pipe diameter when measured along the crotch of the bend;

(c) the bend shall not have a deflection of more than 1.5° for each wrinkle on pipe of 406 millimetres or more in diameter; and

(d) the longitudinal seam shall be as near as practicable to the neutral axis of the bend on pipe containing a longitudinal weld.

Protection from hazards

6.14 An operator shall take practicable steps to protect

(a) each transmission line or the mains from a washout, flood, unstable soil, landslide or other hazard which may cause the pipeline to move or to sustain abnormal load, and

(b) an offshore pipeline from damage by a mudslide, water current, hurricane, ship anchor and fishing operation.

6.15 An operator shall protect each aboveground transmission line or the main that is not located offshore or within an inland navigable water area, from accidental damage by vehicular traffic or other similar cause

(a) by placing the transmission line or the mains at a safe distance from the traffic, or

(b) by installing a barricade.

6.16 A pipeline, including a pipe riser, on each platform located offshore or within inland navigable waters shall be protected from accidental damage by vessels.

Installation of pipe in a ditch

6.17 An operator shall protect a transmission line that is required to be installed in a ditch to be operated at a pressure that produces a hoop stress of 20% or more of the specified minimum yield strength.

6.18 The transmission line shall be installed so that the pipe fits the ditch to minimize the stress and protect the pipe coating from damage.

6.19 When a ditch for a transmission line or main is backfilled, it shall be backfilled in a manner which

(a) provides firm support under the pipe, and

(b) prevents damage to the pipe and pipe coating from equipment or from backfill material.

6.20 Except otherwise provided in this Schedule, any offshore pipe in water at a depth of at least 3.66 metres but not exceeding 61 metres measured from mean low tide, shall be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by other equivalent means.

Installation of plastic pipe

6.21 Subject to paragraphs 6.27 and 6.28, a plastic pipe shall be installed below ground level.

6.22 A plastic pipe, which is installed in a vault or any other below grade enclosure, shall be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

6.23 A plastic pipe shall be installed to minimize shear tensile stress.

6.24 A thermoplastic pipe, which is not encased, shall have a minimum wall thickness of 2.29 millimetres, except that a pipe with an outside diameter of 22.3 millimetres or less may have a minimum wall thickness of 1.58 millimetres.

6.25 A plastic pipe which is not encased shall have an electrically conducting wire or other means of locating the pipe while it is underground provided that

(a) tracer wire is not wrapped around the pipe and contact with the pipe is minimised;

(b) tracer wire and any other metallic element installed for the purpose of pipe location shall be resistant to corrosion damage, by the use of coated copper wire or by other means.

6.26 A plastic pipe which is to be encased shall be inserted into the casing pipe in a manner that will protect the plastic and the leading end of the plastic shall be enclosed before insertion.

6.27 An operator may install an uncased plastic pipe temporarily above ground level under the following conditions:

(a) the cumulative aboveground exposure of the pipe shall not exceed the manufacturer's recommended maximum period of exposure or two years, whichever is less,

(b) the pipe shall be located in a position where it is well protected against damage, and

(c) the pipe shall be located where it can resist exposure to ultraviolet light and high and low temperatures.

6.28 An operator may install a plastic pipe on a bridge if it

(a) is installed with protection against mechanical damage,

(b) is protected from ultraviolet radiation, and

(c) does not exceed the pipe temperature limit specified in paragraph 2.18 to 2.21 of the Second Schedule.

Casing

6.29 An operator shall use casing on a transmission line or the mains under a railway or highway if it

(a) is of a design that can withstand a superimposed load, or

(b) has its ends sealed if there is a possibility of water entering the casing.

6.30 If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the operator shall ensure that the design of the casing correlates to the pressure at a stress level of not more than 72% of the specified minimum yield strength.

6.31 If a vent is installed on a casing, the vent shall be protected from wet weather to prevent water from entering the casing.

Underground clearance

6.32 An operator shall install a transmission line which has at least 305 millimetres of clearance from any other underground structure that is not associated with the transmission line and in the absence of this clearance shall ensure that the transmission line is protected against damage which is likely to occur as a result of the proximity of other structures.

6.33 Each main transmission line shall be installed with enough clearance from any other underground structure to permit proper maintenace and to protect against damage that is likely to result from proximity to any other structure.

6.34 In addition to meeting the requirements in paragraphs 6.32 and 6.33, each plastic transmission line or the mains shall be installed with sufficient clearance, and be insulated, from any source of heat to prevent the impairment of the serviceability of the pipe.

6.35 Each pipe-type or bottle-type holder shall be installed with a minimum clearance from any holder as prescribed in paragraph 3.61 of the Third Schedule.

Cover

6.36 Subject to paragraphs 6.38 to 6.40, each buried transmission line shall be installed with a minimum cover as follows:

Location	Normal soil Millimetres	Consolidated rock Millimetres
Class 1 locations	762	457
Class 2, 3, and 4 locations	914	6109
Drainage ditches of public road and railroad crossings	914	610

6.37 Subject to paragraph 6.38, a person shall install a buried main line with at least 610 millimetres cover.

6.38 Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand any anticipated external load.

6.39 Subject to paragraph 6.38, any pipe installed in a navigable river, stream or harbour shall be installed with a minimum cover of 1,219 millimetres in soil or 610 millimetres in consolidated rock between the top of the pipe and the underwater natural bottom.

6.40 Subject to paragraph 6.38, a person who intends to install a pipe underwater offshore at a depth not exceeding 61 metres as measured from the mean low tide, shall comply with the following:

(a) a pipe under water of a depth of not less than 4 metres shall be installed with a minimum cover of 914 millimetres in soil or 457millimetres in consolidated rock between the top of the pipe and the natural bottom, and

(b) a pipe under water at a depth of not less than 4 metres shall be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

Interpretation

6.41 In this Schedule, unless the context otherwise requires,

“arc burn” means arcing;

“arcing” means the effect generated when an electrical current bridges the air gap between two contacts for conductors;

“gauge” means an instrument or device for measuring pressure with a visual display of such information;

“gouge” means a cut or groove as left by something sharp;

“groove” means a long, narrow cut or depression, made to guide motion or receive a corresponding ridge;

“kink” means a sharp twist or curve in something that is otherwise straight;

“pipe riser” means a vertical pipe through which liquid travels upwards;

“pounding out” means to strike repeatedly or forcefully; and

“superimposed load” means a load that is in addition to the nominal weight.

SEVENTH SCHEDULE

(Regulations 20, 21, 24 and 37)

CUSTOMER METERS, SERVICE REGULATORS AND SERVICE LINES

Scope

7.1 This Schedule prescribe the minimum requirements for installing customer meters, service regulators, service lines, service line valves and service line connections to mains.

Protection from damage of customer meters and regulators

Installation requirements

7.2 A person who installs a customer meter or service regulator inside a building shall ensure that

(a) the customer meter or service regulator is in a readily accessible location,

(b) the customer meter or service regulator is protected against corrosion and other damage, and

(c) the customer meter or service regulator is protected against any likely vehicular damage and the buried upstream regulator.

7.3 A service regulator that is installed outside a building required to be installed within a building shall be located as near as possible to the point of the service line entrance.

7.4 Each meter required to be installed within a building shall be located in a ventilated peace and at a distance of not less than 914 millimetres from any source of ignition or any source of heat, which might damage the meter.

7.5 Where feasible, the upstream regulator in a series shall be located outside the building, unless it is located in a separate metering or regulating building.

Protection from vacuum or back pressure

7.6 If a customer's equipment is likely to create a vacuum or a back pressure, a device shall be installed to protect the system.

Service regulator vents and relief vents

7.7 (1) A service regulator vent and relief vent shall terminate outdoors.

(2) The outdoor terminal of a service regulator vent or relief vent shall

(a) be rain and insect resistant,

(b) be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building, and

(c) be protected from damage caused by submergence in an area where flooding may occur.

Pits and vaults

7.8 A pit or vault which houses a customer meter or regulator at a place where vehicular traffic is anticipated, shall be of the capacity able to support the traffic.

Installation of customer meter and regulator

7.9 A meter or regulator shall be installed to minimise anticipated stress on the connecting piping and the meter.

7.10 When a close all-threaded nipple is used, the wall thickness remaining after the thread is cut, shall meet the minimum wall thickness requirements prescribed in this Schedule.

7.11 A connection made of lead or other easily damaged material shall not be used in the installation of a meter or a regulator.

7.12 A regulator which might release gas in its operation shall be vented to the outside atmosphere.

Operating pressure for customer meter installations

7.13 A meter shall not be used at a pressure which is more than 67% of the manufacturer's shell test pressure.

7.14 A person who intends to install a new meter shall test it to a minimum of 69 kPa gauge.

7.15 A rebuilt or repaired tinned steel case meter shall not be used at a pressure that exceeds 50% of the pressure used to test the meter after rebuilding or repairing.

Installation of service lines

Depth

7.16 Subject to paragraph 7.17 each buried service line shall be installed with at least 305 millimetres of cover in a private property and at least 457 millimetres of cover in a public area.

7.17 Where an underground structure prevents installation at the depths specified in paragraph 7.16, the service line shall be installed in a manner that will enable the service line, withstand any anticipated external load.

Support and backfill

7.18 A service line shall be properly supported on undisturbed or well-compacted soil.

7.19 The material used for the backfill for the installation of a service line shall be devoid of any element that is likely to damage the pipe or its coating.

Grading for drainage

7.20 Where condensate in gas is likely to cause interruption in the gas supply to the customer, the service line shall be graded so as to drain into the main line or into drips at the low points in the service line.

Protection against piping strain and external loading

7.21 Each service line shall be installed so as to minimise anticipated piping strain and external loading.

Installation of service lines into buildings

7.22 Each underground service line installed below grade through the outer foundation wall of a building shall

(a) be protected against corrosion, in the case of a metal service line,

(b) be protected from shearing action and any backfill settlement in the case of a plastic service line, and

(c) be sealed at the foundation wall to prevent leakage into the building.

7.23 A vent line from the annular space shall extend to a point where gas cannot be a hazard and extend above grade terminating in a rain and insect resistant fitting if the conduit is sealed.

Installation of service lines under buildings

7.24 Where an underground service line is installed under a building

(a) it shall be encased in a gastight conduit,

(b) the conduit and the service line shall, extend into a normally usable and accessible part of the building, if the service line supplies the building it underlies, and

(c) the space between the conduit and the service line shall be sealed to prevent gas leakage into the building if the conduit is sealed at both ends.

Locating underground service lines

7.25 Each underground non-metallic service line, which is not encased, shall have a means to locate the pipe requirements in compliance with paragraph 6.25 of the Sixth Schedule.

Valve requirements of service line

7.26 A service line shall have a service-line valve which meets the applicable requirements of the First and Third Schedules except that a valve incorporated in a meter bar, which allows the meter to be bypassed, shall not be used as a service-line valve.

7.27 A person shall not use a soft seat service line valve if its ability to control the flow of gas is likely to be adversely affected by exposure to anticipated heat.

7.28 Each service line valve on a high-pressure service-line, installed above ground or in an area where the blowing of gas may be hazardous, shall be designed and constructed to minimise the possibility of the removal of the core of the valve with any special tool.

Location of valves of service lines

Relation to regulator or meter

7.29 A service-line valve shall be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

Outside valves

7.30 A service line shall have a shut-off valve in a readily accessible location that is outside the building if feasible.

Underground service line valves

7.31 Each underground service-line valve shall be located in a covered durable curb box or standpipe which permits the ready operation of the valve and is supported independently of the service line.

General requirements for connections to main piping of service lines

Location of service line connection

7.32 A service line connection to a main line shall be located at the top of the main line or at the side of the mainline if it is not practicable, unless a suitable protective device is installed to minimise the possibility of dust and moisture being carried from the main into the service line.

Compression-type connection to main

7.33 A person who intends to install a compression-type service line to the mainline connection shall

(a) ensure that the line is of the requisite design,

(b) install it to effectively sustain the longitudinal pull out or thrust force caused by contraction or expansion of the piping, or anticipated external or internal loading, and

(c) ensure that any gasket used in connecting the service line is compatible with the kind of gas in the system.

Connection of service line to cast iron or ductile iron mains

7.34 A person shall connect a service line to a cast iron or ductile iron mainline by a mechanical clamp, drilling and tapping the mainline, or by any other method that meets the requirements of paragraph 5.3 to 5.6 of the Fifth Schedule.

7.35 Where a threaded tap is inserted, the requirements of paragraphs 3.24 and 3.25 of the Third Schedule shall apply.

Steel service lines

7.36 A person shall construct a pipe that has a design for a minimum of 689 kPa gauge for a steel service line.

Cast iron and ductile iron service lines

7.37 A cast iron or ductile iron pipe that is not more than 152 millimetres in diameter shall not be installed for a service line.

7.38 Where a cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through a building wall shall be a steel pipe.

7.39 A cast iron or ductile iron service line shall not be installed in unstable soil or under a building.

Plastic service lines

7.40 A person who intends to install a plastic service line outside a building shall install it below ground level.

7.41 Despite paragraph 7.40 a plastic service line

(a) shall be installed in accordance with paragraph 6.27 of the Sixth Schedule,

(b) may terminate above ground level and outside a building if

(i) the above ground level part of the plastic service line is protected against deterioration and external damage, and

(ii) the plastic service line is not used to support any external load.

7.42 A plastic service line inside a building shall be protected against external damage.

Copper service lines

7.43 A copper service line installed within a building shall be protected against external damage.

New service lines not in use

7.44 An operator who installs a service line which is not placed in service after completion of installation shall comply with one of the following conditions until the customer is supplied with gas:

(a) the valve which is closed to prevent the flow of gas to the customer shall be provided with a locking device or other means designed to prevent the opening of the valve by a person other than a person authorised by the operator;

(b) a mechanical device or fitting which will prevent the flow of gas shall be installed in the service line or in the meter assembly; or

(c) the customer's piping shall be physically disconnected from the gas supply and the open pipe sealed.

Excess flow valve performance standard for service lines

7.45 A person who installs an excess flow valve to be used on a single residence service line that would operate continuously throughout the year at a pressure of not less than 69 kPa gauge, shall ensure that each valve

(a) functions properly up to the maximum operating pressure at which the valve is rated,

(b) functions properly at all temperatures reasonably expected in the operating environment of the service line,

(c) at 69 kPa gauge

(i) will close at 50% or more above, the rated closure flow rate specified by the manufacturer,

(ii) upon closure, for an excess flow valve, designed to allow pressure to equalise across the valve, reduce gas flow to a level not exceeding 5% percent of the manufacturer's specified closure flow rate, up to a maximum of 0.57 cubic meter per hour,

(iii) upon closure, for an excess flow valve, designed to prevent equalisation of pressure across the valve, reduces gas flow to no more than 0.01 cubic meter per hour; and

(d) does not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified flow rate.

7.46 Without limiting the effect of the requirements of the First and Third Schedules, a person who installs a valve shall ensure that each valve shall on closure reduce the gas flow.

7.47 An operator shall mark or otherwise identify the presence of an excess flow valve in the service line.

7.48 An operator shall locate an excess flow valve as near as practical to the fitting that connects the service line to its source of gas supply.

7.49 An operator shall not install an excess flow valve on a service line where

(a) that operator has prior knowledge of the presence of any contaminant in the gas system, and the presence of the contaminant could reasonably be expected to cause the excess flow valve to malfunction, or

(b) the excess flow valve is likely to interfere with the necessary operation and any maintenance activity on the service line.

Contents of excess flow valve customer notification

7.50 A written notice to a customer shall contain an explanation in respect of the following:

(a) that an excess flow valve that meets the performance standards prescribed in paragraphs 7.45 to 7.49, is available for the operator to install if the customer bears the cost associated with the installation;

(b) the potential safety benefits which may be derived from the installation of an excess flow valve, including the explanation that an excess flow valve is designed to shut off flow of natural gas automatically if the service line breaks;

(c) that if the customer requests the operator to install an excess flow valve, the customer, in addition to the cost of installation may later incur cost for the maintenance and replacement of that excess flow valve, and

(d) details of the installation, maintenance and replacement of an excess flow valve.

Interpretation

7.51 In this Schedule, unless the context otherwise requires,

"cost of parts" means the cost of the parts of the excess flow valve required for its installation;

"costs associated with installation" includes the costs directly connected with the installation of an excess flow valve, the cost of parts, labour, inventory and procurement but does not include maintenance and replacement costs until they are incurred;

"service line customer" means a person who pays the gas bill, or a person who requests for a service yet to be established;

"shearing action" means any action that produces forces operating in opposite directions; and

"shell test pressure" means the gauge pressure at which the valve pressure was tested which must be at least 1.5 times the maximum allowed pressure at 38°C rounded off to the next highest one bar increment.

EIGHTH SCHEDULE

(Regulation 25 and 37)

CORROSION CONTROL

Scope

8.1 This Schedule prescribes minimum requirements for the protection of metallic pipelines from external, internal and atmospheric corrosion.

General requirements

8.2 The corrosion control procedures required by this Schedule shall be carried out, by or under the direction of a person qualified in pipeline corrosion control methods.

External corrosion control for buried or submerged pipelines

8.3 Unless a test conducted indicates that a corrosive condition exists, an operator is not required to comply with paragraph 8.11 and 8.16, if the operator can demonstrate by a test, investigation or experience in the area of application, including, as a minimum, a soil resistivity measurement test and the test for corrosion accelerating bacteria, that a corrosive environment does not exist, subject to paragraph 8.4.

8.4 The operator shall within six months of an installation conduct tests to include

(a) a pipe-to-soil potential measurement with respect to a continuous reference electrode or an electrode that uses close spacing, of not more than 6.0 metres, and

(b) a soil resistivity measurement at potential profile peak location to adequately evaluate the potential profile along the entire pipeline.

8.5 An operator is not required to comply with paragraph 8.11 and 8.16, if the operator can demonstrate that

(a) a corrosive environment does not exist in the case of a copper pipe, or

(b) a corrosion during the five-year period of service of the pipeline would not be detrimental to public safety in the case of a temporary pipeline with an operating period of service of not more than five years after installation.

8.6 Despite paragraph 8.3 and 8.5, if a pipeline is externally coated, it shall be cathodically protected in accordance with paragraph 8.16.

8.7 Aluminium shall not be installed in a buried or submerged pipeline.

8.8 Paragraph 8.3 to 8.7, 8.11 and paragraph 8.16 do not apply to an electrically isolated metal alloy fitting in a plastic pipe if

(a) an operator can prove by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition for the size of the fitting used; and

(b) the fitting is designed to prevent leakage caused by localised corrosion pitting.

Examination of buried pipeline exposed to external corrosion

8.9 When an operator has knowledge that a portion of a buried pipeline is exposed, the operator shall examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated.

8.10 If external corrosion that requires remedial action under paragraph 8.58 to 8.74 is detected, the operator shall investigate circumferentially and longitudinally beyond the exposed portion, by visual examination or indirect method or both, to determine whether additional corrosion that requires remedial action exists in the vicinity of the exposed portion.

Protective coating for control of external corrosion

8.11 An operator shall apply an external protective coating on each pipeline for external corrosion control, and this coating whether conductive or insulating shall

(a) be applied on a properly prepared surface,

(b) have sufficient adhesion to the metal surface to effectively resist under film migration of moisture,

(c) be sufficiently ductile to resist cracking,

(d) have adequate strength to resist damage due to handling and soil stress, and

(e) have a property compatible with any supplemental cathodic protection.

8.12 An external protective coating which is of an electrically insulating type shall also have low moisture absorption and high electrical resistance.

8.13 An operator shall inspect external protective coating before the pipe is lowered into the ditch and backfilling is done, and repair any damage detrimental to effective corrosion control.

8.14 The operator shall protect the external protective coating from damage that results from any adverse ditch condition or damage from a supporting block.

8.15 If a coated pipe is insulated by boring, driving or other similar method, the operator shall take precautions to minimise the damage to the coating during installation.

Cathodic protection for control of external corrosion

8.16 An operator shall use a cathodic protection system that

(a) provides a level of cathodic protection which complies with one or more of the applicable criteria specified in paragraph 8.18 to 8.25, or

(b) provides a level of cathodic protection equal to that provided in compliance with one or more of the criteria if none of the criteria in paragraph 8.18 to 8.25 is applicable.

8.17 If an amphoteric metal is included in a buried or submerged pipeline that contains metals of different anodic potential

(a) that amphoteric metal shall be electrically isolated from the remainder of the pipeline and cathodically protected,

(b) the entire buried or submerged pipeline shall be cathodically protected at a cathodic potential which meets the requirements specified in paragraph 8.18 to 8.25 for amphoteric metals; or

(c) the amount of cathodic protection shall be controlled so as not to damage the protective coating or the pipe.

Criteria for cathodic protection and determination of measurements

8.18 The criteria for cathodic protection for steel, cast iron and ductile iron structures is as follows:

(a) a negative cathodic voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell and the determination of this voltage must be made in accordance with paragraph 8.22, 8.24 and 8.25;

(b) a negative cathodic voltage shift of at least 300 millivolts which shall be determined with the protective current applied, and in accordance with paragraph 8.22, 8.24 and 8.25, except that this voltage shift applies to structures not in contact with metals of different anodic potentials;

(c) a minimum negative cathodic polarization voltage shift of 100 millivolts determined in accordance with paragraph 8.23 to 8.25;

(d) a voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve measured in accordance with paragraph 8.24 and 8.25; and

(e) a net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at a predetermined current discharge anodic point of the structure

8.19 The criteria for cathodic protection for an aluminum structure is as follows:

(a) subject to subparagraphs (c) and (d) a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current and the voltage shift must be determined in accordance with paragraph 8.22, 8.24 to 8.25;

(b) subject to subparagraphs (c) and (d) a minimum negative (cathodic) polarization voltage shift of 100 millivolts shall be determined in accordance with paragraph 8.23 to 8.25;

(c) despite the alternative minimum criteria in subparagraphs (a) and (b) where aluminum is cathodically protected at a voltage in excess of 1.20 volts as measured with reference to a copper-copper sulphate half cell in accordance with paragraph 8.24 to 8.25, and compensated for the voltage drop other than that across the structure-electrolyte boundary may suffer corrosion that results from the build-up of alkali on the metal surface but a voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment; and

(d) careful investigation or testing shall be carried out before applying cathodic protection to stop a pitting attack on an aluminum structure in any environment with a natural hydrogen ion concentration in excess of 8.

8.20 The criteria for cathodic protection for a copper structure shall be of a minimum negative cathodic polarization voltage shift of 100 millivolts determined in accordance with paragraph 8.23 to 8.25.

8.21 The criteria for cathodic protection for a metal of a different anodic potential shall be a negative cathodic voltage, measured in accordance with paragraph 8.24 and 8.25, equivalent to that required for the most anodic metal in the system and shall be maintained, except if an amphoteric structure is involved that could be damaged by high alkalinity under subparagraphs (c) and (d), of paragraph 8.17, it must be electrically isolated with an insulating flange, or the equivalent.

Interpretation of voltage measurement.

8.22 A voltage (IR) drop other than that across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in subparagraphs (a) and (b) of paragraph 8.18 and paragraph 8.19 (a).

Determination of polarization voltage shift

8.23 The polarization voltage shift shall be determined by the interruption of the protective current and the measurement of the polarization decay as follows:

(a) when the current is initially interrupted, an immediate voltage shift occurs; and

(b) the voltage reading shall be used as the base reading from which to measure polarization decay in paragraph 8.18 (c), 8.19 (b) and 8.20.

Reference half cell

8.24 Subject to paragraph 8.25, a negative cathodic voltage shall be measured between the structure surface and a saturated copper-copper sulfate half cell that has contact with the electrolyte.

8.25 (a) Other standard reference half cells including saturated potassium chloride calomel half cell of -0.78 volt and silver-silver chloride half cell used in sea water of -0.80 volt may be substituted for the saturated copper-copper sulfate half cell of voltage -0.85 volt.

(b) In addition to the standard reference half cell, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to as a saturated copper-copper sulfate half cell is established.

Monitoring of external corrosion

8.26 A pipeline which is under cathodic protection shall be tested at least once each year and at intervals of not more than fifteen months, to determine whether the cathodic protection meets the requirements of paragraph 8.16 and 8.17.

8.27 If a test at the intervals stipulated in paragraph 8.26 is impractical for a separately and protected short section of the mains of a transmission line, not in excess of 30.43 metres of a separately protected service line, it may be surveyed on a sampling basis if

(a) at least 10% of any protected structure distributed over the entire system is surveyed each year; and

(b) another 10% of the protected structure is checked each subsequent year, so that the entire system is tested at a ten-year periodic interval.

8.28 An operator shall inspect each cathodic protection rectifier or other impressed current power source shall be inspected six times each year, but at intervals not exceeding two and a half months, to ensure that it can operate.

8.29 The operator shall carry out electrical checks on each reverse current switch, diode and interference bond that is likely to jeopardize structure protection six times each year, but at intervals not exceeding fifteen months.

8.30 An interference bond other than that referred to in paragraph 8.29 shall be checked at least once each year, but at intervals of not more than fifteen months.

8.31 An operator shall take prompt remedial action to correct any deficiency indicated by the monitoring.

8.32 After the initial evaluation required by paragraph 8.28 and 8.29, an operator shall, not less than every three years at intervals of not more than thirty-nine months, re-evaluate any unprotected pipeline and cathodically protect it, at least in the area in which active corrosion is found.

8.33 The operator shall determine the areas of active corrosion by

(a) electrical survey except on a distribution line, or

(b) means which include review analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection method and the pipeline environment where an electrical survey is impractical on a transmission line.

Electrical isolation for external corrosion

8.34 A buried or submerged pipeline shall be electrically isolated from an underground metallic structure, unless that pipeline is electrically interconnected and cathodically protected as a single unit.

8.35 An operator shall install one or more insulating devices where the electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

8.36 Except for unprotected copper inserted in a ferrous pipe, an operator shall isolate electrically each pipeline from a metallic casing which is a part of the underground system, if isolation cannot be achieved because it is impractical, or any other measure has to be taken to minimise corrosion of the pipeline inside the casing.

8.37 The operator shall undertake inspection and an electrical test to ensure that the electrical isolation provided is adequate.

8.38 An insulating device shall not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

8.39 Where a pipeline is located in close proximity to an electrical transmission tower footing, ground cable, counterpoise or is located in an area where a faulty current or unusual risk of lightening is likely to occur, the operator responsible shall

(a) provide protection for the pipeline against damage from faulty current or lightening, and

(b) take any protective measure to insulate each device required for use.

Test station for external corrosion control

8.40 An operator shall provide a test station or other contact point for each pipeline under cathodic protection to facilitate the electrical measurement and to determine the adequacy of cathodic protection.

Test lead connection for external corrosion

8.41 A test lead wire shall be connected to a pipeline to enable it remain mechanically secure and electrically conductive.

8.42 A test lead wire shall be attached to a pipeline to minimise stress concentration on the pipe.

8.43 Each bared test lead wire and bared metallic area point of connection to the pipeline shall be coated with an electrical insulating material compatible with the pipe coating and insulation on the wire.

Interference current of external corrosion control

8.44 An operator whose pipeline system is subjected to a stray current shall have in place a continuing programme to minimise the detrimental effects of that current.

8.45 An impressed current type cathodic protection system or galvanic anode system shall be designed and installed so as to minimize any adverse effect on an existing adjacent underground metallic structure.

Internal corrosion control

8.46 Corrosive gas shall not be transported by a pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and the necessary steps have been taken to minimize internal corrosion.

8.47 The operator shall inspect the internal surface of a pipe which has been removed for evidence of corrosion.

8.48 Where internal corrosion is detected,

(a) the pipe adjacent to the pipe removed shall be investigated to determine the extent of internal corrosion;

(b) the pipe shall be replaced to the extent required under paragraph 8.61 to 8.70; and

(c) steps shall be taken to minimise the internal corrosion.

8.49 Gas that contains more than 6 milligrams per cubic metre at standard conditions of hydrogen sulphide shall not be stored in a pipe-type or bottle-type holder.

Monitoring of internal corrosion control

8.50 Where corrosive gas is being transported, a coupon or other suitable means shall be used to determine the effectiveness of the steps taken to minimise internal corrosion.

8.51 Each coupon or other means for monitoring internal corrosion shall be checked twice each year, at intervals of not more than seven and a half months.

Atmospheric corrosion control

8.52 An operator shall clean and coat part of or the whole of each pipeline which is exposed to the atmosphere, except for pipeline specified under paragraph 8.54.

8.53 The coating material shall be suitable for the prevention of atmospheric corrosion.

8.54 Except for a portion of a pipeline in an offshore splash zone or soil-to-air interface, an operator is not required to protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will

(a) only be a light surface oxide, or

(b) not affect the safe operation of the pipeline before the next scheduled inspection.

Monitoring of atmospheric corrosion

8.55 An operator shall inspect a part or a whole of a pipeline which is exposed to the atmosphere for evidence of atmospheric corrosion as follows:

(a) if that pipeline is located onshore, at least once every three years but at intervals of not more than thirty-nine months, and

(b) if that pipeline is located offshore, at least once each year but within intervals not more than fifteen months.

8.56 In the course of every inspection, the operator shall pay particular attention to any pipe that is at soil-to-air interface, under thermal insulation, under a disbanded coating, at pipe support, in a splash zone, at deck penetrations and in a span over water.

8.57 If atmospheric corrosion is detected in the course of an inspection, the operator shall provide protection against the corrosion as required under paragraph 8.52 to 8.54.

General remedial measures for pipes

8.58 Each segment of a metallic pipe which is used to replace pipe removed from a buried or submerged pipeline because of external corrosion shall have a properly prepared surface and shall be provided with an external protective coating that meets the requirements of paragraph 8.11 to 8.15.

8.59 Each segment of metallic pipe which is used to replace pipe removed from a buried or submerged pipeline because of external corrosion shall be cathodically protected.

8.60 Except for a cast iron or ductile iron pipe, each segment of buried or submerged pipe which is required to be repaired because of external corrosion shall be cathodically protected.

Remedial measures for transmission lines

8.61 A segment of a transmission line with general corrosion and with a remaining wall thickness of less than that required for the maximum allowable operating pressure of the pipeline

(a) shall be replaced or its operating pressure reduced to a level commensurate with the strength of the pipe based on the actual remaining wall thickness, or

(b) may be repaired by a method that a reliable engineering test and analyses indicate the permanent serviceability of the pipe.

8.62 For the purpose of paragraph 8.58 to 8.61 and paragraph 8.63 to 8.74, corrosion pitting closely grouped to affect the overall strength of the pipe is considered general corrosion.

Localised corrosion pitting

8.63 A segment of a transmission line with localised corrosion pitting of a degree where leakage may result, shall be replaced or repaired, or its operating pressure shall be reduced to a level commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pit.

8.64 For the purpose of paragraph 8.61 to 8.63, the strength of pipe based on the actual remaining wall thickness may be determined by the procedures specified in Part A of the Fifteenth Schedule.

Remedial measures for distribution lines other than cast iron or ductile iron lines

General corrosion on distribution lines other than cast iron or ductile iron lines

8.65 An operator shall replace each segment of a corroded distribution line pipe other than a cast iron pipe or ductile iron pipe with a remaining wall thickness of less than that required for the maximum allowable operating pressure of the pipeline, or a wall thickness of less than 30% of the nominal wall thickness.

8.66 Despite paragraph 8.65, a corroded pipe may be repaired by a method by which a reliable engineering test and analyses can indicate a permanent restoration of the serviceability of the pipe.

8.67 For the purposes of paragraph 8.65 and 8.66, restoration of corrosion pitting that is closely grouped to affect the overall strength of the pipe, shall be considered as general corrosion.

Localised corrosion pitting

8.68 An operator shall replace or repair a distribution line pipe which is not a cast iron or ductile iron pipe with a localised corrosion pitting to prevent possible leakage.

Remedial measures for cast iron and ductile iron pipelines

General graphitisation of cast iron and ductile iron pipelines

8.69 An operator shall replace the segment of a cast iron or ductile iron pipe on which general graphitisation is detected to a degree where a fracture or a leakage may result.

Localised graphitisation

8.70 An operator shall replace, repair or seal by an internal sealing method the segment of a cast iron or ductile iron pipe on which general graphitisation is detected to a degree where leakage may result to prevent or arrest any possible leakage.

Corrosion control records

8.71 An operator shall maintain a record or map to indicate the location of a cathodically protected piping, cathodic protection facility, galvanic anode and neighbouring structure bonded to the cathodic protection system.

8.72 A record or a map that indicates a stated number of anodes, installed in a stated manner or spacing is not required to indicate the specific distance to each buried anode.

8.73 A record or a map required under paragraph 8.71 shall be retained for as long as the pipeline remains in service.

8.74 An operator shall

(a) maintain a record of each test, survey or inspection required in sufficient detail to demonstrate

(i) the adequacy of any corrosion control, or

(ii) that a corrosive condition does not exist; and

(b) retain the record for at least five years, except that a record related to paragraph 8.26 to 8.33 and paragraph 8.47 to 8.48 shall be retained for as long as the pipe remains in service.

Interpretation

8.75 In this Schedule, unless the context otherwise requires,

“amphoteric structure” means a structure made of materials that are able to react both as a base and an acid;

“corrosion pitting” means a hollow or indentation on the surface of a transmission line caused by corrosion;

“coupon” means pre-weighed strips of metal made of the same material as the pipeline which are inserted into the pipeline and later removed, inspected and weighed again to determine any loss of metal due to corrosion;

“ditch condition” means a mechanical damage caused to a pipeline by narrow channel dug in the ground;

“insulating flange” means a projecting flat rim or collar or a rib of a structure used to isolate the structure from conducting electricity;

“operator” means a person who engages in the transportation of gas;

“pitting attack” means the creation of hollow or indentation on the surface of a transmission line caused by corrosion;

“potential profile” means the voltage difference between two points; and

“protective current” means a current applied to neutralise a positive or negative current developed on the surface of a transmission pipeline.

NINTH SCHEDULE

(Regulations 26 and 37)

TESTING

Scope

9.1 This Schedule prescribes minimum leak-test strength requirements for pipelines.

General requirements

9.2 The test medium for pipeline shall be liquid, air, natural gas, or inert gas, which is

(a) compatible with material of which the pipeline is constructed,

(b) relatively free of sedimentary materials, and

(c) non-flammable, except for natural gas.

9.3 Subject to paragraph 9.5 to 9.7, if air, natural gas or inert gas is used as a test medium, the following hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of specified minimum yield strength	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

9.4 Each joint used to tie in a test segment of pipeline is exempted from the specific test requirements of this Schedule, but each non-welded joint shall be tested for a leakage at not less than its operating pressure.

Strength test requirements for steel pipeline to operate at a hoop stress level of 30% or more above the specified minimum yield strength

9.5 Each segment of a steel pipeline other than a service line which is to operate at a hoop stress of 30% or more above the specified minimum yield strength shall be strength tested to substantiate the proposed maximum allowable operating pressure.

9.6 If there is a building in a Class 1 or Class 2 location, intended for human occupancy within 91 metres of a pipeline, a hydrostatic test shall be conducted to a test pressure of at 1cast 125% of the maximum operating pressure on that segment of the pipeline within 91 metres of that building, except that in no event shall the test section be less than 183 metres unless the length of the newly relocated pipe is less than 183 metres.

9.7 Despite paragraph 9.6, if the building is evacuated while the hoop stress exceeds 50% of the specified minimum yield strength, air or inert gas may be used as the test medium.

9.8 Each compressor station, regulating station and measuring station in a Class 1 or Class 2 location, shall be tested to meet the test requirements of at least a Class 3 location.

9.9 Subject to paragraph 9.11, the strength test shall be conducted by maintaining the pressure at or above the test pressure for at least eight hours.

9.10 Where a component other than a pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that

(a) the component was tested to at least the pressure required for the pipeline to which it is being added;

(b) the component was manufactured under a quality control system which ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

(c) the component carries a pressure rating established through the applicable specifications indicated in Part A of the Fifteenth Schedule or by unit strength calculations specified in paragraphs 3.2 and 3.3 of the Third Schedule.

9.11 In the case of a fabricated unit and the short section of a pipe, for which a post installation test is impractical, a reinstallation strength test shall be conducted through the maintenance of the pressure at or above the test pressure for at least four hours.

Test requirements for pipelines to operate at a hoop stress level less than 30% of the specified minimum yield strength and at or above 689 kPa gauge.

9.12 Each segment of a pipeline, other than a service line and plastic pipeline, which is to be operated at a hoop stress of less than 30% of the specified minimum yield strength and at or above 689 kPa gauge shall be tested.

9.13 An operator of a pipeline shall use a test procedure which ensures the discovery of every potentially hazardous leak in the segment tested.

9.14 If during the test, the segment is to be stressed to 20% or more of the specified minimum yield strength and natural gas, inert gas or air is the test medium

(a) a leak test shall be carried out at a pressure of between 689 kPa gauge and the pressure required to produce a hoop stress of 20% of the specified minimum yield strength; or

(b) the pipeline shall be surveyed to check for any leak while the hoop stress is held at approximately 20% of the specified minimum yield strength.

9.15 The pressure shall be maintained at or above the test pressure for at least one hour during the test.

Test requirements for pipelines to operate below 689kPa gauge

9.16 Each segment of a pipeline, other than a service line and plastic pipeline, which is to be operated below 689 kPa gauge shall be leak tested.

9.17 The test procedure used shall ensure discovery of every potentially hazardous leak in the segment being tested.

9.18 Each main which is to be operated at less than 7 kPa gauge shall be tested to at least 69 kPa gauge and each main required to be operated at or above 7 kPa gauge shall be tested to at least 621 kPa gauge.

Test requirements for service lines

9.19 Each segment of a service line, other than a plastic service line, shall be leak tested in accordance with this Schedule before it is placed in service and in case of a service line connection to the main it shall be

(a) included in the test if feasible, or

(b) subject to a leakage test at the operating pressure when placed in service if not feasible.

9.20 Each segment of a service line, other than a plastic service line, intended to be operated at a pressure of at least 7 kPa gauge but not more than 276 kPa gauge shall be given a leak test at a pressure of not less than 345 kPa gauge.

9.21 Each segment of a service line, other than a plastic service line, intended to be operated at a pressure of not more than 276 kPa gauge shall be tested to at least 621 kPa gauge, but the segment of a steel pipe stressed to 20% or more of the specified minimum yield strength shall be tested in accordance with paragraph 9.12 to 9.15.

Test requirements for plastic pipelines

9.22 Each segment of a plastic pipeline shall be tested.

9.23 The test procedure for the segment of a plastic pipeline shall ensure the discovery of every potentially hazardous leak in the segment being tested.

9.24 The required test pressure for the procedure shall be at least 150% of the maximum operating pressure or 345 kPa gauge, whichever is greater except that the test pressure shall not be more than three times the pressure determined under paragraph 2.17 of the Second Schedule, at a temperature of not less than the pipe temperature during the test.

9.25 The temperature of thermoplastic material in the course of the test shall not be more than 38 kPa or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

Environmental protection and safety requirements

9.26 An operator shall ensure that every reasonable precaution is taken to protect employees and the general public during testing.

9.27 Whenever the hoop stress of the segment of the pipeline being tested is likely to exceed 50% of the specified minimum yield strength, the operator shall take every reasonable step to keep any person who is not working on the testing operation, outside the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

9.28 The operator shall ensure that the test medium is disposed of in a manner which would minimise damage to the environment.

Records of tests performed

9.29 An operator shall make and retain for the useful life of the pipeline, a record of each test performed under paragraph 9.5 to 9.15.

9.30 The record shall include the following information:

(a) the operator's name,

(b) the name of the operator's employee responsible for performing the test,

(c) the name of any test company used,

(d) the test medium used,

(e) the test pressure,

(f) the duration of the test,

(g) the pressure recording charts or other record of pressure reading,

(h) the elevation variation, whenever significant for the particular test, and

(i) the leak and failures noted and their disposition.

9.31 The operator shall maintain a record of each test required under paragraph 9.16 to 9.25 for at least five years.

TENTH SCHEDULE

(Regulations 27, 29 and 37)

UPRATING

Scope

10.1 This Schedule prescribes the minimum requirements for increasing the maximum allowable operating pressures or uprating for pipelines.

Pressure increase

10.2 Where this Schedule requires an increase in pressure, the pressure shall be made in increments at a rate, which can be controlled in accordance with the following conditions:

(a) at the end of each incremental increase, the pressure shall be held constant while the entire segment of pipeline which is affected is checked for leaks;

(b) each leak detected shall be repaired before any further pressure increase is made; and

(c) each leak shall be repaired as soon as practicable after the uprating.

Limitation to increase in maximum allowable operating pressure

10.3 A new maximum allowable operating pressure established in this Schedule shall not exceed the maximum pressure allowable under paragraph 11.36 to 11.38 of the Eleventh Schedule for a new segment of pipeline constructed of the same material in the same location.

10.4 If a variable necessary to determine the design pressure under the design formula is unknown, the maximum allowable operating pressure may be increased as provided in paragraph 2.3 of the Second Schedule when uprating a steel pipeline.

Uprating to a pressure which will produce a hoop stress of 30% or more of the specified minimum yield strength in steel pipelines

10.5 A person shall not subject any segment of a steel pipeline to an operating pressure which will produce a hoop stress of 30% or more of the specified minimum yield strength and which is above the established maximum allowable pressure unless the requirements of this Schedule have been met.

10.6 An operator shall review the design, operation and maintenance history and previous testing of the segment of a pipeline and determine whether the proposed increase is safe and consistent with the requirements of this Schedule before increasing the operating pressure above the previously established maximum allowable operating pressure.

10.7 An operator shall make any repair, replacement or alteration in the segment of a pipeline that is necessary for the safe operation at the increased pressure before increasing the operating pressure above the previously established maximum allowable operating pressure.

10.8 After compliance with paragraphs 10.6 and 10.7, an operator may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(a) the segment of pipeline is successfully tested in accordance with the requirements of this Schedule for a new line, of the same material, in the same location;

(b) an increased maximum allowable operating pressure may be established for a segment of a pipeline in a Class 1 location if the line has not previously been tested and if

(i) it is impractical to test it in accordance with the requirements of this Schedule;

(ii) the new maximum operating pressure does not exceed 80% of that allowed for a new line of the same design in the same location; and

(iii) the operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this Schedule.

10.9 Where a segment of a pipeline is uprated in accordance with paragraph 10.8(b), the increase in pressure shall be made in increments equal to

(a) 10% of pressure before uprating; or

(b) 25% of total pressure increase,

whichever produces the fewer number of increments.

Uprating of steel, plastic, cast iron and ductile iron pipelines

10.10 A person shall not subject

(a) a segment of a steel pipeline to an operating pressure that will produce a hoop stress of less than 30% of the specified minimum yield strength and that is above the previously established maximum allowable operating pressure; or

(b) a plastic, cast iron or ductile iron pipeline segment to an operating pressure which is above the previously established maximum allowable pressure.

10.11 An operator shall, before any increase in the operating pressure above the previously established maximum allowable operating pressure

(a) review the design, operation and maintenance history of the segment of a pipeline,

(b) make a leakage survey, if the last survey was undertaken more than a year ago, and repair any leak which is detected except for a

(i) a leak that is determined not to be potentially hazardous, or

(ii) a leak that is monitored during the pressure increase and that does not become potentially hazardours,

(c) make any repair, replacement, or alteration in the segment of a pipeline which is necessary for the safe operation at the increased pressure,

(d) reinforce or anchor any offset, bend or dead end in a pipe joined by a compression coupling or bell and spigot joint to prevent failure of the pipe joint, if the offset, bend or dead end is exposed,

(e) isolate the segment of a pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure,

(f) install a service regulator on each service line and test each regulator to determine that it is functioning if the pressure in the mains or service line, or both, is to be higher than the pressure delivered to the customer, and

(g) increase pressure if necessary to test each regulator that has been installed on each pipeline subject to the increased pressure.

10.12 After compliance with paragraph 10.11, the increase in the maximum allowable operating pressure shall be effected in increments which are equal to 69 kPa gauge or 25% of the total pressure increase, whichever produces the fewer number of increments.

10.13 Where subparagraphs (f) and (g) of paragraph 10.11 apply, there shall be at least two approximately equal incremental increases.

10.14 If the record for a cast iron or ductile iron pipeline facility is not accurate enough to determine the stress produced by internal pressure, trench loading, rolling load, beam stress and other bending load, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the operator shall comply with the following procedures:

(a) in estimating the stress, the operator shall assume that the cast iron pipe was supported on blocks with tamped backfill and that a ductile iron pipe was laid without blocks with tamped backfill, if the original laying conditions cannot be ascertained,

(b) the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and use the greatest cover measured unless the actual maximum cover depth is known,

(c) the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths, unless the actual maximum cover depth is known, and

(d) the coupons shall be cut from the pipe lengths in areas where the cover depth is most likely to be the greatest.

10.15 The average of all measurements taken shall be increased by the allowance indicated in the following table:

	Allowable millimetres		
Cast iron pipe size in millimetres	Cast iron pipe		Ductile iron pipe
	Pit cast pipe	Centrifugally cast pipe	
76 to 203	2	2	2
254 to 305	2	2	2
762 to 1067	2	2	2

1219	2	2	2
1372 to 1524	2	-	-

10.16 In the case of a cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 765 megapascals gauge and a modulus of rupture of 214 megapascals gauge.

Records

10.17 An operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required.

Written Plan

10.18 An operator who uprates a segment of pipeline shall establish a written plan that will ensure that each applicable requirement of this Schedule is complied with.

Interpretation

10.19 In this Schedule, unless the context otherwise requires,

"beam stress" means a stress in the plane of a beam resulting from load that acts perpendicular to the plane of the beam;

"bell joint" means a connection between two sections of pipe, with the straight end of one section inserted in the bell end of the adjoining section and the joint sealed by a caulking compound or with a compressible ring;

"compression coupling" means a connection between two perfectly aligned sections of a pipe with the joint sealed with a compressible ring;

"offset" means the amount or distance by which a pipeline is out of line;

"pit cast pipe" is a method where a pit is used to cast pipes;

"rolling load" means a load imposed on a pipe due to a moving weight;

"spigot joint" means a connection between two sections of pipe, with the end of a smaller pipe of one section inserted in the flared end of the adjoining section and the joint sealed by a caulking compound or with a compressible ring;

"tamped backfill" means laterite used to fill a previously excavated opening and that has been rammed as desired; and

"trench loading" means the load imposed on a pipe due to the weight of soil on the pipe.

ELEVENTH SCHEDULE

(Regulations 30, 31, 33 and 37)

OPERATION OF PIPELINES

Scope

11.1 This Schedule prescribes the minimum requirements for the operation of pipeline facilities.

11.2 A person shall not operate a segment of a pipeline unless it is operated in accordance with the provisions of this Schedule.

Procedural manual for operations, maintenance and emergencies

Maintenance and normal operations

11.3 A manual for operation of pipelines shall include procedures for the following matters:

(a) the operation, maintenance and repair of pipelines;

(b) control corrosion in accordance with the operations and maintenance requirements of the Eighth Schedule;

(c) accessibility of construction records, maps and operation history to appropriate operating personnel;

(d) collation of data required for the report of incidents in a timely and effective manner;

(e) the start up and shut down of any part of the pipeline in a manner designed to assure operation within the maximum allowable operating pressure limits prescribed and the build-up allowed for the operation of any pressure-limiting and control device;

(f) the commencement, operation and shut down of gas compressor units;

(g) periodic review of the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operations and maintenance and modification of the procedures when deficiencies are detected;

(h) adequate precautions in excavated trenches to protect personnel from the hazard of unsafe accumulation of vapour or gas and the availability when needed at the excavation of an emergency rescue equipment, including a breathing apparatus and a rescue harness and line;

(i) systematic and routine testing and inspection of pipe-type or bottle holders including

(i) the provision for the detection of external corrosion before the strength of the container has been impaired,

(ii) periodic sampling and testing of gas in storage to determine the dew point of vapours contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant, and

(iii) periodic inspection and testing of pressure limiting equipment to determine that it is in a safe operating condition and has adequate capacity; and

(j) the prompt response to the report of gas odour inside or near a building, subject to the application of an operator's emergency procedures under paragraph 11.23 (c).

Abnormal operation

11.4 In the case of a transmission line, the manual required under paragraph 11.3 shall include procedures for the following matters when operating design limits have been exceeded:

(a) response to, investigation and correction of the cause of

(i) the unintended closure of a valve or shutdown;

(ii) the increase or decrease in pressure or flow rate outside the normal operating limit;

(iii) the loss of communication;

(iv) an operation and safety device; and

(v) any other unforeseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to any person or property;

(b) the checking variations from normal operation after abnormal operation has ended at sufficient critical location in the system to determine continued integrity and safe operation;

(c) notification of the responsible operator personnel when notice of an abnormal operation is received;

(d) periodic review of the response of operator personnel to determine the effectiveness of the procedures that control abnormal operation and the taking of corrective measures where deficiencies are detected; and

(e) the procedures required under paragraph 11.14, paragraph 11.22 to 11.25 and paragraph 11.34 and 11.35, in respect of surveillance, emergency response and accident investigation shall be included in the manual required under paragraph 11.3.

Required study of change in class location

11.5 When an increase in population density indicates a change in the class location for a segment of an existing steel pipeline that operates at a hoop stress level which exceeds 40% of the specified minimum yield strength, or indicates that the hoop stress that corresponds to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator concerned shall immediately undertake a study to determine

(a) the present class location for the segment involved,

(b) the design, construction and testing procedure followed in the original construction, and a comparison of the procedure with that required for the present class location by the applicable provisions of this Schedule,

(c) the physical condition of the segment to the extent that it can be ascertained from available records,

(d) the operating and maintenance history of the segment,

(e) the maximum actual operating pressure and corresponding operating hoop stress, for the segment of pipeline involved, taking pressure gradient into account, and

(f) the actual area affected by the population density increase and physical barrier or other factor which may limit further expansion of the more densely populated area.

Confirmation or revision of maximum allowable operating pressure with change in class location

11.6 If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the existent class location, and the segment is in a satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline shall be confirmed or revised to comply with one of the following requirements:

(a) if the segment involved has been previously tested for a period of not less than eight hours, the maximum allowable operating pressure shall be

(i) .0.8 times the test pressure in a Class 2 location,

(ii) 0.667 times the test pressure in a Class 3 location, or

(iii) 0.555 times the test pressure in a Class 4 location and the corresponding hoop stress shall not exceed 72% of the specified minimum yield strength of the pipe in a Class 2 location, 60% of specified minimum yield strength in a Class 3 location or 50% of the specified minimum yield strength in a Class 4 location;

(b) the maximum allowable operating pressure of the segment involved shall be reduced so that the corresponding hoop stress is not more than that permissible for any new segment of a pipeline in the existing class location;

(c) the segment involved shall be tested in accordance with the applicable requirements of the Ninth Schedule and its maximum allowable operating pressure shall be established according to the following criteria:

(i) the maximum allowable operating pressure after the re-qualification test is 0.8 times the test pressure for a Class 2 location, 0.667 times the test pressure for a Class 3 location, and 0.555 times the test pressure for a Class 4 location;

(ii) the corresponding hoop stress shall not exceed 72% of the specified minimum yield strength of the pipe in a Class 2 location, 60% of the specified minimum yield strength in a Class 3 location, or 50% of the specified minimum yield strength in a Class 4 location.

11.7 The maximum allowable operating pressure confirmed or revised in accordance with this Schedule, shall not exceed the maximum allowable operating pressure established before the confirmation or revision.

11.8 The confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this Schedule does not preclude the application of paragraph 10.2 to 10.16 of the Tenth Schedule.

11.9 Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under paragraph 11.5 shall be completed within twenty four months of the change in class location.

11.10 The pressure reduction under paragraph 11.6 (a) or (b) within the twenty-four month period does not preclude establishing a maximum allowable operating pressure under paragraph 11.6 (c).

Underwater inspection and reburial of pipeline

11.11 An operator shall prepare and follow the procedure to identify its pipeline in waters that are less than 5 metres deep as measured from low water that is at risk of being exposed under water that is a hazard to navigation.

11.12 An operator shall conduct appropriate periodic underwater inspections of its pipeline in waters less than 5 metres deep as measured from mean low water, based on the identified risk.

11.13 If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, that operator shall

(a) promptly, but not later than twenty-four hours after discovery, notify the Commission and Ghana Maritime Authority by telephone, followed by a written notification of the location and the available geographic coordinates of that pipeline;

(b) promptly, but not later than seven days after discovery, mark the location of the pipeline at the ends of the pipeline segment and at intervals not exceeding 457 metres in length except that a pipeline segment of less than 183 metres in length need only be marked at the centre; and

(c) within six months after discovery, bury the pipeline so that the top of the pipeline is 914 millimetres below the under-water natural bottom for normal excavation or 457 millimetres for rock excavation.

Continuing surveillance

11.14 An operator shall establish a procedure for continuous surveillance of its facilities to determine and take appropriate action that concerns any change in location, failure, leakage history, corrosion, substantial change in cathodic protection requirements, and any other unusual operation and maintenance condition.

11.15 Where a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exist, the operator shall initiate a programme to recondition or phase out the segment involved, or reduce the maximum allowable operating pressure in accordance with paragraphs 11.36 and 11.37.

Damage prevention programme

11.16 An operator of a pipeline shall establish a written programme to prevent damage to that pipeline from excavation activities.

11.17 (1) Except as provided in paragraph 11.20 and 11.21 of this Schedule, each operator of a buried pipeline shall carry out, in accordance with this Schedule, a written programme to prevent damage to that pipeline from excavation activities.

(2) For the purpose of this section, the term “excavation activities” includes excavation, blasting, boring, tunneling, backfilling, the removal of above ground, structures by either explosive or mechanical means, and other earth moving operations.

11.18 (1) An operator may comply with any of the requirements of paragraph 11.19 through participation in a public service programme, such as a one call system, but such participation does not relieve the operator of responsibility for compliance with this Schedule.

(2) Despite paragraph 11.18(1), an operator must perform the duties under paragraph 11.19(c) through participation in a one-call system.

(3) In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another.

(4) An operator's pipeline system must be covered by a qualified one-call system where there is one in place.

(5) For the purpose of this paragraph, a one-call system is considered as a “qualified one-call system” if it meets the following requirements;

(a) it is operated by one or more of the following:

(i) a person who operates underground pipeline facilities or other underground facilities;

(ii) a private contractor;

(iii) a state or local government agency; or

(iv) a person who is otherwise eligible by law to operate a one-call notification system;

(b) it receives and records information from excavators about intended excavation activities;

(c) it promptly transmits to the appropriate operators of underground pipeline facilities the information received from excavators about intended excavation activities;

(d) it maintains a record of each notice of intent to engage in an excavation activity for the minimum time set by the State or, in the absence of such time, for the time specified in the applicable law of limitations on tort actions; and

(e) it tells persons giving notice of intent to engage in an excavation activity the names of participating operators of underground pipeline facilities to whom the notice will be transmitted.

11.19 The damage prevention programme required by paragraph 11.17 must, at a minimum:

(a) include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located;

(b) provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in subparagraph (a) of the following as often as needed to make them aware of the damage prevention programme:

(i) the programme's existence and purpose; and

(ii) how to learn the location of underground pipelines before excavation activities are begun;

(c) provide a means of receiving and recording notification of planned excavation activities;

(d) if the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings;

(e) provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins;

(f) provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) the inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline, and

(ii) in the case of blasting, any inspection must include leakage surveys.

11.20 A damage prevention programme in this schedule is not required for the following pipelines:

(a) pipelines located offshore; and

(b) pipelines to which access is physically controlled by the operator.

11.21 Pipelines operated by persons other than municipalities including operators of master meters whose primary activity does not include the transportation of gas need not comply with the following:

(a) the requirement of paragraph 11.17 that the damage prevention programme be written; and

(b) the requirements of paragraphs 11.19 (a) and 11.19 (b).

Emergency procedures

11.22 An operator of a pipeline shall establish a written procedure to minimise the hazard that may result from a gas pipeline emergency.

11.23 The procedure shall provide for the following:

(a) receipt, identification and classification of notices of events which require immediate response by the operator;

(b) establishment and maintenance of adequate means of communication with the appropriate fire, police or other public officer;

(c) the prompt and effective response to a notice of each type of emergency, including

(i) gas detected inside or near a building,

(ii) fire located near or directly involving a pipeline facility,

(iii) any explosion occurring near or directly involving a pipeline facility, and

(iv) natural disaster;

(d) the availability of personnel, equipment, tools and materials, as required at the scene of an emergency;

(e) actions directed toward the protection of people first and then property;

(f) emergency shut down and pressure reduction in any section of the operator's pipeline system necessary to minimise any hazard to life or property;

(g) provision of safety against any actual or potential hazard to life or property;

(h) notification of appropriate fire, police or other public officer of gas pipeline emergency and coordination with the official planned response and actual response during an emergency;

(i) safe restoration of any service outage; and

(j) the initiation of investigations under paragraphs 11.34 and 11.35 as applicable, as soon as practicable after the emergency.

11.24 An operator shall

(a) furnish its management personnel who are responsible for emergency action with a copy of the latest edition of the emergency procedures established under paragraphs 11.22 and 11.23;

(b) train appropriate operating personnel to ensure that they are knowledgeable of emergency procedures and verify that the training is effective; and

(c) review employee activity to determine whether the procedures were effectively followed in each emergency.

11.25 An operator shall establish and maintain liaison with the appropriate public officer to

(a) understudy the responsibility and resources of each government organisation that is required to respond to a gas pipeline emergency,

(b) acquaint the public officer with the operator's ability in response to a gas pipeline emergency,

(c) identify the types of gas pipeline emergencies of which the operator is required to notify the public officer, and

(d) plan how the operator and public officer can engage in mutual assistance to minimise hazard to life and property.

Public awareness

11.26 A pipeline operator shall develop and implement a written continuous public education programme that follows the guidelines specified in Part C of the Fifteenth Schedule.

11.27 An operator's programme shall follow the general programme recommendations specified in Part A of the Fifteenth Schedule to assess the unique attributes and characteristics of the operator's pipeline and facility.

11.28 An operator shall follow the general programme recommendations specified in Part A of the Fifteenth Schedule, unless that operator provides justification in its programme or procedural manual as to why compliance with any of the provisions of the recommended practice is not practicable and not necessary for safety.

11.29 The operator's programme shall specifically include provisions to educate the public, appropriate government department or agency and any person engaged in excavation related activity on the

(a) use of a one-all notification system prior to excavation and other damage prevention activity;

(b) possible hazards associated with the unintended release of gas from a gas pipeline facility;

(c) physical indications that a release of gas may have occurred;

(d) steps that are required to be taken for public safety in the event of a gas pipeline release; and

(e) procedures for reporting on a gas pipeline release.

11.30 The programme shall include activities to advise an affected municipality, school district, business and residents of a pipeline facility location.

11.31 The programme and the media used shall be comprehensive and designed to cover every area in which the operator transports gas.

11.32 The programme shall be conducted in English and in any other Ghanaian language commonly understood by a significant concentration of the population in the operator's area of operation.

11.33 The operator's programme documentation and evaluation results shall be made available for periodic review by the relevant appropriate regulatory agencies.

Investigation of failure

11.34 An operator shall establish a procedure for analysing an accident or failure for the purpose of the determination of the cause of failure and minimising the possibility of a recurrence.

11.35 The procedure shall include a process for the selection of samples of the failed facility or equipment for laboratory examination where applicable.

Maximum allowable operating pressure for steel or plastic pipelines

11.36 A person shall not operate a segment of a steel or plastic pipeline at a pressure that exceeds the lowest pressure of any of the following:

(a) the design pressure of the weakest element in the segment, determined in accordance with the Second and Third Schedules except in the case for a steel pipe in a pipeline that is converted for use or uprated in accordance with the Tenth Schedule; or

(b) the pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) in the case of plastic pipe in any location, the test pressure shall be divided by a factor of 1.5;

(ii) in the case of steel pipe operated at 689 kPa gauge or more, the test pressure shall be divided by a factor determined in accordance with the table below; or

(iii) the pressure determined by the operator to be the maximum safe pressure after consideration of the history of the segment, particularly known corrosion and the actual operating pressure.

Class location	*Factors, Segment
1	1.1
2	1.25
3	1.5
4	1.5

* For segments installed, uprated or converted, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

11.37 A person shall not operate a segment to which paragraph 11.36(b) (iii) is applicable, unless an over-pressure protective device is installed on the segment in a manner which will prevent the maximum allowable operating pressure from being exceeded, in accordance with paragraphs 3.82 to 3.83 of the Third Schedule.

11.38 Despite the requirements of this Schedule, an operator may operate a segment of a pipeline found to be in a satisfactory condition at the highest operating pressure to which the segment was subjected after consideration of its operation and maintenance history.

Maximum allowable operating pressure of a high-pressure distribution system

11.39 A person shall not operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures:

(a) the design pressure of the weakest element in the segment, determined in accordance with the Second and Third Schedules;

(b) 414kPa gauge, for a segment of a distribution system otherwise designed to operate to exceed 414kPa gauge, unless the service line in the segment is equipped with a service regulator or other pressure limiting device in a series that meets the requirements of paragraph 3.86 of the Third Schedule.

(c) 172 kPa gauge in a segment of a cast iron pipe in which there are unreinforced bell and spigot joints;

(d) the pressure limit to which a joint may be subjected without the possibility of its parting; or

(e) the pressure determined by the operator to be the maximum safe pressure after consideration of the history of the segment, particularly known corrosion and actual operating pressures.

11.40 A person shall not operate a segment of a pipeline to which paragraph 11.39 (e) applies, unless an overpressure protective device is installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with paragraph 3.82 to 3.83 of the Third Schedule.

Maximum and minimum allowable operating pressure for a low-pressure distribution system

11.41 A person shall not operate a low-pressure distribution system at a pressure to render unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

11.42 A person shall not operate a low pressure distribution system at a pressure that is lower than the minimum pressure at which the safe and continuous operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

Odorization of gas

11.43 A combustible gas in a distribution line shall contain a natural odorant or be odorized by an operator so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

11.44 An operator shall ensure that a combustible gas in a transmission line in a Class 3 or Class 4 location meets the requirements of paragraph 11.43, unless

(a) at least 50% of the length of the line downstream from that location is in a Class 1 or Class 2 location; or

(b) at least 50% of the length of a lateral line which transports gas to a distribution centre is in a Class 1 or Class 2 location.

11.45 An operator shall ensure that the odorant in combustible gas in the concentration in which it is used shall not be deleterious to any person, material or pipe.

11.46 Any product from the odorant shall not be toxic when breathed in or be corrosive or harmful to any material to which the product of combustion will be exposed.

11.47 The odorant shall not be soluble in water to an extent that exceeds 2.5 parts to 100 parts by weight.

11.48 The equipment for odorization must introduce the odorant without wide variation in the level of odorant.

11.49 To assure proper concentration of the odorant in accordance with this Schedule, each operator shall with the use of an instrument capable of determining the percentage of gas in air at which the odour becomes readily available, conduct periodic sampling of combustible gases.

11.50 An operator of a master meter system shall comply with paragraph 11.49 by

(a) obtaining written verification from any gas supplier that the gas has the proper concentration of odorant, and

(b) conducting a periodic “sniff” test at the extremities of the system to confirm that the gas contains odorant.

Tapping pipelines under pressure

11.51 A tap fixed on a pipeline under pressure shall be fixed by a qualified person.

Purging pipelines

11.52 When a pipeline is being purged of air by use of gas, the gas shall be released into one end of the line in a moderately rapid and continuous flow.

11.53 If a supplier of gas cannot supply gas in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, the operator concerned shall release a slug of inert gas into the line before the gas is supplied.

11.54 When a pipeline is being purged of gas by the use of air, the air shall be released into one end of the line in a moderately rapid and continuous flow.

11.55 If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, the operator shall release a slug of inert gas into the line before the air.

Interpretation

11.56 In this Schedule, unless the context otherwise requires,

“bell joint” means a connection between two sections of pipe, with the straight end of one section inserted in the bell end of the adjoining section and the joint sealed by a caulking compound or with a compressible ring;

“breathing apparatus” means a device that facilitates breathing in the case of a respiratory failure;

“dew point” means the atmospheric temperature (varying according to pressure and humidity) below which water droplets begin to condense and dew can form;

“excavation activities” includes excavation, blasting, boring, tunnelling, backfilling, the removal of above ground structures by either explosive or mechanical means, and other earth moving operations;

“inert gas” means a gas that at ambient conditions does not react chemically with other materials;

“mean low water” means the average level of low tide for any area;

“one-all notification” means a system where information on all related works are embodied in one notice;

“pipeline facility location” means the location of new and existing pipeline, right of way and any equipment, facility or building used in the transportation of gas or in the treatment of gas during the cause of transportation;

“pit cast pipe” means a pipe manufactured using the method where a pit is used to cast pipes;

“rescue harness” means a support consisting of an arrangement of straps for holding something to a body;

“slug” means a quantity of a substance;

“sniff test” means having a person sniff around to detect the presence of odorizing agent;

“spigot joint” means a connection between two sections of pipe with the end of a smaller pipe of one section inserted in the flared end of the adjoining section and the joint sealed by a caulking compound or with a compressible ring; and

“underwater natural bottom” means the floor of waterbody.

TWELFTH SCHEDULE

(Regulations 30, 31 and 37)

MAINTENANCE

Scope

12.1 This Schedule prescribes the minimum requirements for the maintenance of pipeline facilities.

12.2 An operator shall replace, repair or remove from service each segment of pipeline which becomes unsafe.

12.3 An operator shall repair a hazardous leak promptly.

Patrol programme for transmission line

12.4 An operator shall establish a patrol programme to observe the surface conditions on and adjacent to the transmission line right-of-way for the detection of leak and construction activity, and any other factor that may affect the safety and operation of a transmission line.

12.5 The frequency of patrols shall be determined by the size of the line, the operating pressure, the class location, terrain, weather and any other relevant factor.

12.6 Despite paragraph 12.5, the intervals between patrols shall not be longer than the periods prescribed in the following table:

Class location of line	Maximum interval between patrols	
	At highway and railroad crossings	At all other places
1 and 2	7 months, but at least twice each calendar year	15 months, but at least once each calendar year
3	4 months, but at least four times each calendar year	7 months, but at least twice each calendar year
4	4 months, but at least four times each calendar year	4 months, but at least four times each calendar year

Leakage survey of transmission line

12.7 The leakage survey of a transmission line shall be conducted at intervals of not more than fifteen months, but at least once each year.

12.8 Despite paragraph 12.7 and subject to paragraphs 11.43 to 11.50 of the Eleventh Schedule, the leakage survey of a transmission line with the use of a leak detector equipment shall be conducted as follows:

(a) in a Class 1 or 2 location at intervals of not more than fifteen months, but at least once each year;

(b) in a Class 3 location, at intervals of not more than seven months, but at least twice each year; and

(c) in a Class 4 location, at intervals of not more than five months, but at least four times each year.

General requirements for repair procedures for transmission lines

12.9 An operator shall take an immediate temporary measure to protect the public

(a) where a leak, imperfection or damage which impairs serviceability of a transmission line is detected in a segment of a steel transmission line that operates at or above 40% of the specified minimum yield strength; and

(b) if there is a need for permanent repair as soon as practicable but it was not feasible to make a permanent repair at the time of discovery.

12.10 An operator shall use a welded patch as a means of repair, subject to paragraph 12.14(b)(iii).

Permanent field repair of imperfection and damage of transmission line

12.11 An imperfection or damage which impairs the serviceability of a pipe in a steel transmission line that operates at or above 40% of the specified minimum yield strength shall be

(a) removed by cutting out and replacing a cylindrical piece of that pipe, or

(b) repaired by a method by which a reliable engineering test and analyses can permanently restore the serviceability of the pipe.

12.12 The operating level shall be at a safe level during repair operations.

Permanent field repair of weld of transmission line

12.13 A weld which is unacceptable under paragraph 4.12 to 4.13 of the Fourth Schedule be repaired as follows:

(a) the weld shall be repaired in accordance with the requirements of paragraph 4.20 to 4.24 of the Fourth Schedule if it is practical to take the segment of the transmission line out of service,

(b) a weld may be repaired in accordance with paragraph 4.20 to 4.24 of the Fourth Schedule while the segment of a transmission line is in service if

(i) the weld is not leaking;

(ii) the pressure in the segment is reduced so that it does not produce a stress that is more than 20% of the specified minimum yield strength of the pipe; or

(iii) grinding of the defective area can be limited so that at least 3 millimetres thickness of the pipe weld remains; or

(c) by the installation of a full encirclement welded split sleeve of appropriate design.

Permanent field repair of leak on transmission line

12.14 A permanent field repair of a leak on a transmission line shall be effected by

(a) the removal of the leak by cutting out and replacing a cylindrical piece of pipe; or

(b) the repair of the leak through

(i) the installation of a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by a mechanical coupling and operates at less than 40% of the specified minimum yield strength,

(ii) the installation of a properly designed bolt-on-leak clamp, if the leak is caused by corrosion,

(iii) the filleting of a weld over the pitted area and a steel plate patch with rounded corners of the same or greater thickness than the pipe, at not more than one-half of the diameter of the pipe size if the leak is due to a corrosion pit and on pipe of not more than 267 megapascals of the specified minimum yield strength,

(iv) the application mechanically of the full encirclement of the split sleeve of the appropriate design, if the leak is on a submerged offshore pipeline or submerged pipeline within inland navigable waters, and

(v) the application of a method by which a reliable engineering test or analyses can indicate the permanent restoration of the serviceability of the pipe.

Testing of replacement pipes on transmission lines

12.15 If a segment of a transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder the replacement pipe shall be tested to a pressure required for a new line installed in the same location, and the test may be carried out on the replacement pipe before it is installed.

12.16 A repair that is carried out by welding in accordance with paragraph 12.11 to 12.14 shall be inspected in accordance with paragraph 4.10 to 4.13 of the Fourth Schedule.

Patrol of distribution system

12.17 The frequency of patrol of the mains shall be determined by

(a) the severity of the conditions that are likely to cause failure or leakage, and

(b) the consequent hazards to public safety.

12.18 The mains in a place or on a structure where anticipated physical movement or external loading may cause failure or leakage shall be patrolled

(a) in a business district, at intervals of not more than five months, but at least four times each year; and

(b) outside any business district, at intervals of not more than seven months, but at least twice each year.

Leakage survey and procedure of distribution system

12.19 An operator of a distribution system shall conduct periodic leakage surveys in accordance with this Schedule.

12.20 The type and scope of the leakage control programme shall be determined by the nature of the operations and the local conditions, but must meet the following minimum requirements:

(a) a leakage survey with leak detector equipment shall be conducted at intervals of not more than fifteen months but at least once each year in a business district,

(b) a leakage survey shall include tests of the atmosphere in gas, electricity, telephone, sewer and water system manholes, at any crack in a pavement sidewalk, and at any other location that provides an opportunity for finding a gas leak,

(c) a leakage survey with a leak detector equipment shall be conducted outside a business district as frequently as required, but at least once every five years at intervals of not more than sixty-three months, and

(d) a leakage survey shall be conducted for a cathodically unprotected distribution line at least once every three years at intervals of not more than thirty-nine months subject to paragraph 8.26 to 8.33 of the Eighth Schedule.

Test requirements for reinstating service lines

12.21 Subject to paragraphs 12.22 and 12.23, a disconnected service line shall be tested in the same manner as a new service line before being reinstated.

12.22 A service line temporarily disconnected from the mains shall be tested from the point of disconnection to the service line valve in the same manner as a new service line before a reconnection.

12.23 Despite paragraph 12.22, if provisions are made to maintain a continuous service, such as the installation of a bypass, any part of the original service used to maintain continuous service, is not required to be tested.

Compressor station

Procedures for gas compressor unit

12.24 An operator shall establish starting, operation and shut down procedures for each gas compressor unit for which that operator is responsible.

Inspection and testing of relief device of compressor station

12.25 Except for a rupture disc, each pressure relieving device in a compressor station shall

(a) be inspected and tested by the operator involved in accordance with paragraph 12.34 to 12.35 and 12.39 to 12.42; and

(b) be operated periodically to ensure that it opens at the correct pressure set.

12.26 An operator that detects any defective or inadequate equipment, shall promptly repair or replace it.

12.27 An operator shall inspect and test each remote control shutdown device and test it at intervals of not more than fifteen months, but at least once each year, to determine that it functions properly.

Isolation of equipment for maintenance or alteration of compressor station

12.28 An operator shall establish a procedure for the maintenance of a compressor station of which that operator is responsible and the procedure shall include measures for the isolation of units or for the return to service.

Storage of combustible materials for compressor station

12.29 An operator shall store any flammable or combustible material in a quantity that exceeds that required for everyday use at a safe distance away from a compressor building.

12.30 Aboveground oil or gasoline storage tanks shall be protected in accordance with the standard in accordance with the Fire Precaution (Premises) Regulations, 2003 (L.I. 1724) and the codes of practice developed by the Ghana National Fire Service Council.

Gas detection system of compressor station

12.31 Each compressor building shall have a fixed gas detection and alarm system, unless the building is

(a) constructed in a manner that exposes 50% of its upright side area permanently open, or

(b) located in an unattended field compressor station of 746 kilowatts or less.

12.32 Subject to paragraph 12.33, a gas detection and alarm system shall

(a) continuously monitor the compressor building for a concentration of gas in air of not more than 25% of the lower explosion limit; and

(b) have a device to warn any person about to enter the building and persons inside the building of the danger, if concentration of gas is detected.

12.33 A gas detection system and an alarm system shall be maintained, and a performance test shall be carried out to ensure their proper functioning.

Inspection and testing of pressure limiting and regulating stations

12.34 A pressure limiting station, relief device, rupture disc, and a pressure regulating station and its equipment shall be subjected to inspection and tests at intervals of not more than fifteen months, but at least once each year to ensure that it is

(a) in a good mechanical condition,

(b) adequate from the standpoint of capacity and reliability of operation for the service in which it is employed, and

(c) set to control or relieve at the correct pressure consistent with the required pressure limits of paragraph 3.89 of the Third Schedule.

12.35 Where the maximum allowable operating pressure of a steel pipe is 414 kPa gauge or more, the control or relief pressure limit shall be as follows:

(a) if the maximum allowable operating pressure produces a hoop stress that is greater than 72% of the specified minimum yield strength, then the pressure limit is the maximum allowable operating pressure plus 4%, and

(b) if the maximum allowable operating pressure produces a hoop stress unknown as a percentage of the specified minimum yield strength, then the pressure limit is a pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and maximum allowable operating pressure.

Telemetering or recording gauge of pressure limiting and regulating station

12.36 A distribution system supplied by more than one district pressure regulating station shall be equipped with a telemetering or recording pressure gauge to indicate the pressure in the district.

12.37 Where a distribution system is supplied by a single district pressure regulating station, the operator concerned shall determine the necessity of the installation of a telemetering or recording gauge in the district, taking into consideration the number of customers supplied, the required operating pressure, the capacity of the installation, and any other regulating conditions.

12.38 Where there is an indication of an abnormally high or low pressure, the operator shall inspect the regulator and auxiliary equipment, and take the necessary measures to correct any unsatisfactory operating condition.

Capacity of relief devices for pressure limiting and regulating stations

12.39 A pressure relief device at a pressure limiting station or a pressure regulating station shall have sufficient capacity to protect any facility to which it is connected.

12.40 The capacity of a pressure relief device shall be

(a) consistent with the pressure limits under paragraphs 3.88 and 3.89 of the Third Schedule; and

(b) determined at intervals of not more than fifteen months, but at least once each year, by testing the devices in place or by a review and computation.

12.41 If review and computation are used to determine whether a device has sufficient capacity, the calculated capacity shall be compared with the rated or experimentally determined relieving capacity of the device for the condition under which it operates, except that subsequent computation is not required if the annual review document indicates that a parameter has not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

12.42 If a relief device is not of sufficient capacity, an operator shall install a new or additional device to improve the capacity required under paragraphs 12.39 and 12.40.

Valve maintenance of transmission line

12.43 An operator shall inspect and partially operate each transmission line valve that may be required during an emergency at intervals of not more than fifteen months, but at least once each year.

12.44 An operator shall take prompt remedial action to correct any valve detected to be inoperable, unless that operator designates an alternative valve.

Valve maintenance of distribution line.

12.45 An operator shall check and service each valve, the use of which may be necessary for the safe operation of a distribution system, at intervals of not more than fifteen months, but at least once each year.

12.46 An operator shall take prompt remedial action to correct any valve detected to be inoperable, unless the operator designates an alternative valve.

Vault maintenance

12.47 An operator shall inspect each vault housing pressure regulating and pressure limiting equipment with a volumetric internal content of 5.66 cubic metres or more, at intervals of not more than fifteen months, but at least once each year, to determine that it is in good physical condition and adequately ventilated.

12.48 Where gas is found in a vault, an operator shall inspect the

(a) equipment in the vault for leaks, and any leak detected shall be repaired; and

(b) ventilating equipment to determine that it is functioning properly.

12.49 An operator shall inspect each vault cover to ensure that it does not pose a hazard to public safety.

Prevention of accidental ignition.

12.50 An operator shall take steps to minimize the danger of the accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion.

12.51 Without limiting paragraph 12.50, an operator shall

(a) remove the potential source of ignition from an area in which a hazardous amount of gas is being vented into open air, and provide an extinguisher to minimise any likely danger,

(b) not perform a gas or electric welding or cutting on a pipe or pipe component which contains a combustible mixture of gas and air in the relevant area of work, and

(c) post a warning sign, where appropriate, to alert any person of accidental ignition of gas.

Caulked bell and spigot joint

12.52 A cast iron caulked bell and spigot joint which is subject to a pressure that exceeds 172 kPa gauge shall be sealed with

(a) a mechanical leak clamp, or

(b) a material or device which

(i) does not reduce the flexibility of the joint,

(ii) permanently bonds, chemically or mechanically, with the bell and spigot metal surface or adjacent pipe metal surface, or

(iii) seals and bonds, in a manner that meets the strength, environment, and chemical compatibility requirements of paragraph 1.2(a) and (b), of the First Schedule and paragraph 3.2 of the Third Schedule.

12.53 A cast iron or spigot joint that is subject to a pressure of 172 kPa gauge or less and is exposed for any reason, shall be sealed by a means other than caulking.

Protecting cast-iron pipelines

12.54 When an operator has knowledge that support for a segment of a buried cast-iron pipeline is disturbed, that operator shall

(a) ensure that the segment of that pipeline is protected, against damage during vibration caused by

(i) heavy construction equipment, a train, truck, bus or blasting,

(ii) the impact of force of a vehicle,

(iii) earth movement,

(iv) the apparent future excavation near the pipeline, or

(v) any other foreseeable outside force which may subject that segment of pipeline to bending stress; and

(b) take appropriate steps as soon as practicable,

(i) to provide permanent protection for the disturbed segment from damage that is likely to result from any external load, and

(ii) to comply with the applicable requirements of paragraph 6.14(a) and paragraphs 6.17 to 6.20 of the Sixth Schedule and paragraphs 7.18 to 7.21 of the Seventh Schedule.

Information on abandonment and decommissioning of facilities

12.55 The operators must inform the Energy Commission three months prior to the abandonment and decommissioning of a pipeline facility and the operators must include in their information to the Commission reasons for the abandonment and decommissioning, and the location, size, date and procedure to carry out the decommissioning.

12.56 The operator must submit to the Energy Commission a decommissioning report which must contain all reasonably available information related to the facility, including information in the possession of a third party, the location, size, date, method of abandonment and a certification that the facility has been abandoned in accordance with all the applicable laws.

12.57 (1) An operator shall submit reports to the Commission by

(a) post or hand delivery to the Office of the Energy Commission,

(b) facsimile, or

(c) electronic mail.

(2) Where the operator submits a notice by facsimile or electronic mail, the operator shall confirm the notice by a hard copy.

Interpretation

12.58 In this Schedule, unless context otherwise requires,

"bending stress" means a force per unit area imposed on a pipe as a result of an external force to create a bend;

"bolt-on-leak clamp" means the application of a bolted clamp to stop a leak on a pipe;

"clamp" means a device used to hold or secure objects tightly together to prevent movement or separation through the application of inward pressure;

"district" means a division of a territory marked off for administrative or electoral purposes;

"district pressure regulating station" means a pressure regulating station which serves a district;

"encirclement welded split sleeve" means a method for repairing pipelines which involves the use of sleeve of similar material split and wrapped around the damaged area;

"inert gas" means a gas that at ambient conditions does not react chemically with other materials;

"mechanical coupling" means a connection between two perfectly aligned sections of a pipe with the joint sealed;

"mechanical leak clamp" means a clamp that is fastened on a pipe to prevent leakage;

"pitted area" means an area on a pipeline with a hollow or indentation on the surface caused by corrosion;

"spigot joint" means a connection between two sections of pipe, with the end of a smaller pipe of one section inserted in the flared end of the adjoining section and the point sealed by a caulking compound or with a compressible ring;

"split sleeve" means a method for repairing pipelines which involves the use of a sleeve of similar material split and wrapped around the damaged area;

"steel plate patch" means a pitted area that has been mended or strengthened with a steel plate; and

"telemetering" means to measure transmit and receive data automatically from a distant source.

THIRTEENTH SCHEDULE

(Regulation 38)

QUALIFICATION OF PIPELINE PERSONNEL

Scope

13.1 This Schedule prescribes the minimum requirements for the qualification of individuals who perform qualified tasks on a pipeline facility.

Qualification programme

13.2 An operator shall establish and follow a written qualification programme approved by the Energy Commission.

13.3 The programme shall include provisions to

(a) identify qualified covered tasks;

(b) ensure through evaluation that individuals performing covered tasks are qualified;

(c) allow an individual who is not qualified to perform a covered task under the supervision and direction of a person who is qualified;

(d) evaluate an individual if the operator has reason to believe that, that individual's performance of a covered task has contributed to an incident;

(e) evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

(f) communicate to an individual who performs a covered task any change that may affect the covered task;

(g) identify the covered task and intervals at which evaluation of an individual's qualifications is required;

(h) provide training, when appropriate, to ensure that an individual who performs a covered task has the necessary knowledge and skill to perform the task in a manner that ensures the safe operation of a pipeline facility; and

(i) notify the Commission if the operator significantly modifies the programme after the Commission has verified compliance with this Schedule.

Record keeping

13.4 An operator shall maintain qualification records to include

(a) identification of qualified individuals,

(b) identification of the covered task an individual is qualified to perform,

(c) any date of current qualification, and

(d) qualification methods.

13.5 The record that supports an individual's current qualification shall be maintained while the individual performs the covered task.

13.6 The record of any prior qualification and of an individual who no longer performs a covered task shall be retained for a period of five years.

13.7 The work performance history of the covered task by an individual shall not be used as a sole evaluation method.

13.8 The observation of the on the job performance shall not be used as the sole method of evaluation.

FOURTEENTH SCHEDULE

(Regulations 40 and 42)

PIPELINE INTEGRITY MANAGEMENT

Scope

14.1 This Schedule prescribes the minimum requirements for an integrity management programme on any gas transmission pipeline covered in the Schedules, except that the requirements of paragraphs 14.28 to 14.49; 14.52 to 14.60; paragraphs 14.122 to 14.133 and paragraphs 14.134 to 14.145 of this Schedule are applicable to transmission pipelines constructed of plastic.

Identification of high consequence area

General

14.2 An operator shall identify a high consequence area in accordance with paragraph 14.3.

14.3 An operator may in identifying a high consequence area apply

(a) one method to its entire pipeline system, or

(b) one method to individual portions of the pipeline system.

14.4 An operator shall describe in its integrity management programme which method to be applied to each portion of the operator's pipeline system for purposes of identifying a high consequence area.

14.5 The description of an integrity management programme shall include the potential impact radius when it is utilised to establish a high consequence area.

Identified site

14.6 An operator shall identify an identified site from information the operator has obtained through the routine operation and maintenance activities and from public officials with responsibility for safety or emergency response or planning who can indicate to the operator that they know of a location which meets the identified site criteria.

14.7 If the public official informs the operator that the information required is unavailable, the operator shall use one of the following sources, as appropriate, to identify the site

(a) visible marking such as a sign,

(b) a document of the site licensed or registered by a government department or agency, or

(c) a list or map maintained by or available from a government agency and available to the general public.

Newly identified areas

14.8 When an operator has information that the area around a pipeline segment not previously identified as a high consequence area meets the requirement of a high consequence area, the operator shall complete the evaluation in accordance with the procedures determined by the Commission.

14.9 Where the segment is determined to meet the criteria of a high consequence area, the operator shall incorporate into the operator's baseline assessment plan the fact that the area is a high consequence area within one year from the date the area was identified.

Operator implementation

General

14.10 An operator of a covered pipeline segment shall establish, follow and continuously review an integrity management programme which contains the elements contained in paragraph 14.18 to 14.20 which addresses the risk on each covered transmission pipeline segment.

14.11 The initial integrity management programme shall include

(a) a framework that describes the process for the implementation of each programme element;

(b) guidelines on how relevant decisions will be made and by whom;

(c) a timeline for the completion of the work to implement the programme element; and

(d) an indication of how information gained from experience will be continuously incorporated into the programme.

Implementation standards

14.12 An operator shall comply with the requirements specified for integrity management in Part A of the Fifteenth Schedule.

14.13 Despite paragraph 14.12, an operator may follow an equivalent standard or practice if the operator demonstrates that the alternative standard or practice provides an equivalent level of safety to the public and property.

14.14 In the event of a conflict between the requirements of this Schedule and the standards specified in Part A of the Fifteenth Schedule, the requirement of this Schedule shall prevail.

Changes in integrity management

General

14.15 An operator shall document any change to its integrity management programme and reasons for the change before implementation of the change.

Notification

14.16 An operator shall notify the Commission of any change to the programme which may substantially affect the programme's implementation or may significantly modify the programme or schedule for carrying out any part of the programme.

14.17 The operator shall provide the notification within thirty days after the adoption of this method of change to the programme.

Elements of an integrity management programme

14.18 An operator's integrity management programme may begin with an initial framework which will evolve into a more detailed and comprehensive integrity management programme.

14.19 An operator shall make continuous improvements to its programme.

14.20 The initial programme framework and the subsequent programme shall, at a minimum, contain the following elements:

(a) an identification of every high consequence area in accordance with paragraph 14.2 to 14.9;

(b) a baseline assessment plan that meets the requirements of paragraph 14.50 to 14.60;

(c) an identification of threats to each covered pipeline segment, that includes data integration and a risk assessment in compliance with paragraph 14.28 to 14.49 and to the evaluation of the merits of additional preventive and mitigative measures as specified in paragraph 14.122 to 14.133 for each covered segment;

(d) a direct assessment plan, if applicable, that meets the requirements of paragraph 14.61 to 14.63 and depending on the threat assessed, of paragraphs 14.64 to 14.95 or paragraph 14.96 to 14.97;

(e) provisions that meet the requirements of paragraph 14.104 to 14.121 in respect of remedying conditions detected during integrity assessment;

(f) a process for continuous evaluation and assessment that meets the requirements of paragraph 14.134 to 14.145;

(g) a plan for confirmatory direct assessment that meets the requirements of paragraph 14.98 to 14.103, if applicable;

(h) provisions to meet the requirements of paragraph 14.122 to 14.133 in respect of additional preventive and mitigative measures to protect a high consequence area;

(i) a performance plan outlined in accordance with the requirements specified in Part A of the Fifteenth Schedule and which includes performance measures that meet the requirements of paragraph 14.172 to 14.175;

(j) record keeping provisions in compliance with paragraph 14.176;

(k) a management of change process as specified in Part A of the Fifteenth Schedule;

(l) a quality assurance process;

(m) a communication plan which meets the requirements specified in Part A of the Fifteenth Schedule which includes procedures for addressing safety concerns raised by the Commission;

(n) procedures for ensuring that each integrity assessment is conducted in a manner that minimises environmental and safety risks; and

(0) a process for identification and assessment of newly identified high consequence areas.

Programme deviations

Deviation

14.21 An operator that uses a performance-based approach or a prescriptive integrity management programme that satisfies the requirements for exceptional performance in paragraph 14.22 may deviate from certain requirements for a high consequence area.

Exceptional performance

14.22 An operator shall demonstrate the exceptional performance of its integrity management programme through the following actions:

(a) the provision of a performance-based integrity management programme that meets or exceeds the requirements in Part A of the Fifteenth Schedule which is in respect of

(i) a comprehensive process for risk analysis,

(ii) a risk factor data used to support the programme,

(iii) a comprehensive data integration process,

(iv) a procedure to apply lessons learned from the assessment of a covered pipeline segment to a pipeline segment not covered,

(v) a procedure for the evaluation of every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management programme,

(vi) a performance matrix that demonstrates that the programme has been effective in ensuring the integrity of covered segments by the control of the identified threat to the covered segment,

(vii) semi-annual performance measure beyond that required in paragraph 14.172 to 14.175 that are part of the operator's performance plan which the operator must submit by electronic or other means, on a semi-annual frequency to the Commission,

(viii) an analysis that supports the desired integrity reassessment interval, and

(ix) the remedy to be used for all covered segments;

(b) the provision of at least two integrity assessments on each covered pipeline segment subject to the performance-based approach;

(c) a proof that each assessment effectively addresses the identified threat on a covered segment;

(d) the remedy for every anomaly identified in the most recent assessment in accordance with paragraph 14.104 to 14.121; and

(e) the incorporation of results and lessons learned from the most recent assessment into the operator's data integration and risk assessment.

14.23 When an operator has demonstrated compliance with the integrity management programme, that operator may deviate from the prescriptive requirements specified in Part A of the Fifteenth Schedule, within

(a) the time frame for reassessment as provided in paragraph 14.146 to 14.157 except that, reassessment by a method in this Schedule shall be carried out at intervals of not more than seven years; or

(b) the time frame for reassessment as provided in paragraph 14.104 to 14.121 if the operator demonstrates that the time frame will not jeopardise the safety of the covered segment.

Personnel knowledge and training

14.24 The integrity management programme shall provide that each supervisor whose responsibility relates to the integrity management programme, possess and maintain a thorough knowledge of the integrity management programme and of the elements for which the supervisor is responsible.

14.25 The integrity management programme must provide that any person who qualifies as a supervisor for purposes of an integrity management programme has appropriate training or experience in the area for which the person is responsible.

14.26 The integrity management programme shall provide the criteria for the qualification of a person

(a) who conducts an integrity assessment permitted in this Schedule,

(b) who reviews and analyses the results for an integrity assessment and evaluation, or

(c) who makes a decision on the action to be taken based on an assessment.

14.27 The integrity management programme shall provide the criteria for the qualification of a person

(a) who implements a preventive and mitigative measure required in this Schedule, including the marking and location of a buried structure; or

(b) who directly supervises excavation work carried out in conjunction with an integrity assessment.

Identification of potential threats to the pipeline integrity and the use of threat identification in an integrity management programme.

Threat identification

14.28 An operator shall identify and evaluate every potential threat to each covered pipeline segment, including any threat indicated in Part A of the Fifteenth Schedule and grouped under the following four categories:

(a) a time dependent threat such as internal corrosion, and stress corrosion cracking;

(b) a static or resident threat, such as fabrication or a construction defect;

(c) a time dependent threat such as third party damage and outside force damage; and

(d) human error.

Data gathering and integration

14.29 An operator shall gather and integrate existing data and information on the entire pipeline that would be relevant to the covered segment to identify and evaluate the potential threat to a covered pipeline segment.

14.30 In the performance or the data gathering and integration, the operator shall comply with the requirements specified in Part A of the Fifteenth Schedule and in any case

(a) gather and evaluate the set of data requirements specified in Part A of the Fifteenth Schedule, and

(b) consider both on the covered segment and similar non-covered segment, past records of corrosion control, continuing surveillance, patrol, maintenance history, internal inspection and any other condition specific to each pipeline in respect of the covered segment and similar non-covered segment.

Risk assessment and management

14.31 An operator shall conduct a risk assessment and management in accordance with the requirements specified in Part A of the Fifteenth Schedule, and consider the identified threat for each covered segment.

14.32 The operator shall use the risk assessment to

(a) prioritise the covered segment from the baseline and continuous assessment required under paragraph 14.50 and 14.51, paragraph 14.52 to 14.60, and paragraph 14.134 to 14.145, and

(b) determine what additional preventive and mitigating measure is needed for the covered segment.

Plastic transmission pipeline

14.33 An operator of a plastic transmission pipe shall assess the threat to each covered segment with the information provided in Part A of the Fifteenth Schedule, and consider any threat unique to the integrity of plastic pipe.

Actions to address particular threats

14.34 If an operator identifies the threat of third party damage, cyclic fatigue, a manufacturing and construction defect, electric resistance weld and corrosion, that operator shall take the actions indicated in paragraph 14.35 to 14.49 to address the threat.

Third party damage

4.35 An operator shall utilise the data integration required under paragraphs 14.29 and 14.30 and comply with the standards specified in Part A of the Fifteenth Schedule to determine the susceptibility of each covered segment to the threat of third party damage.

4.36 Where the operator identifies the threat of third party damage, the operator shall implement a comprehensive additional preventive measure in accordance with paragraph 14.122 to 14.133 and monitor the effectiveness of the preventive measure.

4.37 When conducting a baseline assessment under paragraph 14.52 to 14.60, or a reassessment under paragraph 14.134 to 14.145, an operator shall use an internal inspection tool or external corrosion direct assessment procedure, the operator shall integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where a potential indication of third party damage may exist in the covered segment.

l4.38 An operator shall include procedures in its integrity management programme to address the actions to be taken in response to findings from the data integration.

Cyclic fatigue

14.39 An operator shall evaluate whether cyclic fatigue or any other loading condition, including ground movement and suspension bridge condition, could lead to a failure or a deformation, including a dent or gouge, or other defect in the covered segment.

14.40 For the purpose of the evaluation, the operator shall assume the presence of a threat in the covered segment that may be exacerbated by cyclic fatigue.

14.41 The operator shall use the results from the evaluation together with the criteria used to evaluate the significance of the threat to the covered segment to prioritise the integrity baseline assessment or reassessment.

Manufacturing and construction defects

14.42 If an operator identifies the threat of a manufacturing and construction defect, including a seam defect in the covered segment, the operator shall analyse the covered segment to determine the risk of failure from these defects.

14.43 The analysis shall take into consideration the results prior to any assessment on the covered segment.

14.44 The operator may consider the manufacturing and construction defect to be a stable defect if the operating pressure on the covered segment has not increased beyond the maximum operating pressure experienced during the five years preceding identification of the relevant high consequence area.

14.45 An operator shall prioritise the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment if any of the following changes occur in the covered segment:

(a) operating pressure increases above the minimum operating pressure experienced during the preceding five years;

(b) the maximum allowable operating pressure increases; or

(c) the stresses leading to cyclic fatigue increase.

Electric resistance welded pipe

14.46 If a covered pipeline segment contains a low frequency electric resistance welded pipe, or a lap welded pipe other than a pipe that meets the conditions specified in Part A of the Fifteenth Schedule

(a) any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure; or

(b) the operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years,

the operator shall select an assessment technology or technology with proven application capable of assessing seam integrity and seam corrosion anomalies.

14.47 The operator shall prioritise the covered segment referred to in paragraph 14.46 as a high risk segment for the baseline assessment or a subsequent reassessment.

Corrosion

14.48 Where an operator identifies corrosion on a covered pipeline segment that may adversely affect the integrity of the line, that operator shall evaluate and remedy, every pipeline segment with similar material coating and environmental characteristic.

14.49 If necessary, the operator shall establish a schedule for the evaluation and remedy of a similar segment consistent with the operator's established operating and maintenance procedures in these Schedules.

Baseline assessment plan

14.50 An operator shall include each of the following elements in its written baseline assessment plan:

(a) identification of the potential threat to each covered pipeline segment and the information to support the threat identification;

(b) the method selected to assess the integrity of a pipeline and include an explanation for a selection of the assessment method to address any identified threat to each covered segment;

(c) a schedule for completion of the integrity assessment of each covered segment, including any risk factor considered in establishment of the assessment schedule;

(d) a direct assessment plan that meets the requirements of

(i) paragraph 14.61 to 14.63, if applicable, or

(ii) paragraph 14.64 to 14.72, paragraph 14.73 to 14.95 or paragraph 14.96 to 14.97 depending on the threat to be addressed, and

(e) a procedure to ensure that the baseline assessment is conducted in a manner which minimises environmental and safety risks.

14.51 The integrity assessment method an operator uses shall be based on the threat identified to the covered segment and more than one method may be employed to address every threat to the covered pipeline.

Conducting baseline assessments

Assessment methods

14.52 An operator shall assess the integrity of the pipe line in each covered segment by application of one of the following methods depending on the threat to which the segment is susceptible:

(a) internal inspection or the use of a tool capable of detecting corrosion, and any other threat to which the covered segment is susceptible;

(b) a pressure test conducted in accordance with the Ninth Schedule;

(c) direct assessment to address the threat of external corrosion, internal corrosion and stress corrosion cracking; and

(d) other technologies which an operator demonstrates to provide an equivalent understanding of the condition of the pipe line.

14.53 The operator shall in respect of

(a) an internal inspection tool comply with the requirements specified in Part A of the Fifteenth Schedule, in the selection of the appropriate tool for the covered segment,

(b) justifying an extended reassessment interval use a test pressure in accordance with paragraph 14.146 to 14.157,

(c) direct assessment, conduct it in accordance with the requirements of paragraph 14.61 to 14.72, paragraph 14.73 to 14.95 or paragraph 14.96 to 14.97, and

(d) any other technology,

notify the Commission of the choice one hundred and eighty days before the conduct of the assessment.

Prioritising segments

14.54 An operator shall prioritise the covered pipeline segment for a baseline assessment in accordance with the risk analysis that considers the potential threat to each covered segment.

14.55 The risk analysis shall be concluded in accordance with the requirements of paragraph 14.28 to 14.49.

Assessment for particular threat

14.56 An operator shall take the action required in paragraph 14.34 to address a particular threat it has identified in the choice of an assessment method for the baseline assessment of each covered segment.

Newly identified areas

14.57. When an operator identifies a new high consequence area, that operator shall complete the baseline assessment of the pipeline in the newly-identified high consequence area within two years from the date the area is identified.

Newly installed pipe

14.58 An operator shall complete the baseline assessment of a newly-installed segment of pipe within two years from the date the pipe was installed and the operator may conduct a pressure test in accordance with paragraphs 14.52 (b) and 14.53 (b).

Plastic transmission pipeline

14.59 If the threat analysis required under paragraph 14.33 on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from a cause other than third party damage, an operator shall conduct a baseline assessment in accordance with the requirements of this Schedule.

14.60 The operator shall justify the use of an alternative assessment method which would address any identified threat to a covered segment.

Use of direct assessment to address threat

14.61 An operator shall only use direct assessment as a primary assessment method or as a supplement to any of the other assessment methods permitted in this Schedule to address the identified threat of external corrosion, internal corrosion and stress corrosion cracking.

14.62 An operator shall only use direct assessment as a primary assessment method and shall have a plan which complies with the requirements.

(a) specified in the Fifteenth Schedule and paragraph 14.64 to 14.72, if addressing external corrosion,

(b) specified in the Fifteenth Schedule and paragraph 14.73 to 14.95, if addressing internal corrosion, or

(c) specified in the Fifteenth Schedule and paragraph 14.96 to 14.97, if addressing stress corrosion cracking.

14.63 An operator that uses direct assessment as a supplement assessment method for any applicable threat shall have a plan that follows the requirements of confirmatory direct assessment in paragraph 14.98 to 14.103.

External corrosion direct assessment

External corrosion direct assessment

14.64 An external corrosion direct assessment is a four-step process that combines pre-assessment, indirect inspection, direct examination and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

General requirements

14.65 An operator that uses direct assessment to assess the threat to external corrosion shall comply with the requirements specified in the Fifteenth Schedule.

14.66 The operator shall develop and implement a direct assessment plan which has procedures that address pre-assessment, indirect examination, direct examination, and post-assessment.

14.67 If the external corrosion direct assessment detects pipeline coating damage, the operator shall integrate the data from the external corrosion direct assessment with other information from data integration to evaluate the data from the covered segment for the threat of third party damage, and to address the threat as required by paragraph 14.35 to 14.38.

Pre-assessment

14.68 In addition to the requirements specified in the Fifteenth Schedule the plan for pre-assessment shall include

(a) provisions for the application of a more restrictive criteria for the conduct of external corrosion direct assessment for the first time on a covered segment; and

(b) the basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each external corrosion direct assessment.

14.69 If an operator utilises an indirect inspection method, which is not provided for in the Fifteenth Schedule, the operator shall demonstrate the applicability, validation basis, equipment used, application procedure and utilisation of data for the inspection method.

Indirect examination

14.70 In addition to the requirements specified in the Fifteenth Schedule the procedures contained in the plan for indirect examination of the external corrosion direct assessment region shall include

(a) provisions for the application of a more restrictive criteria in the course of the conduct of external corrosion direct assessment for the first time on a covered segment;

(b) the criteria for identification and documentation of the indices to be considered for excavation and direct examination, which shall include

(i) the known sensitivities of assessment tools;

(ii) the procedures for the use of each tool; and

(iii) the approach to be used for the decrease of the physical spacing of an indirect assessment tool reading when a defect is suspected;

(c) the criteria to define the urgency of excavation and direct examination of each indication identified during the indirect examination and how an operator will define the urgency of the excavation of the indication as immediate, scheduled, or monitored; and

(d) the criteria for scheduling excavation of indices for each urgency level.

Direct examination

14.71 In addition to the requirements specified in the Fifteenth Schedule, the plan's procedures for direct examination of indices from the indirect examination shall include

(a) provision for the application of a more restrictive criteria during the conduct of external corrosion direct assessment for the first time on a covered segment;

(b) the criteria to determine what action should be taken if

(i) any corrosion defect is discovered which exceeds the allowable limit requirements specified in the Fifteenth Schedule,

(ii) the root cause of analysis reveals any condition for which external corrosion direct assessment is not suitable as stipulated in the Fifteenth Schedule,

(c) the criteria for notification procedures for any change in the external corrosion direct assessment plan, including any change that affects

(i) the severity classification,

(ii) the priority of direct examination,

(iii) the time frame for direct examination indication, and

(iv) the criteria that describes how and on what basis an operator will reclassify and reprioritise any of the provisions that are specified in the Fifteenth Schedule.

Post assessment and continuing evaluation

14.72 In addition to the requirements provided in the Fifteenth Schedule, the procedure for post assessment in the plan for the effectiveness of the external corrosion direct assessment process shall include

(a) measures for the evaluation of the long-term effectiveness of external corrosion direct assessment to address external corrosion in a covered segment; and

(b) the criteria for evaluating whether any condition discovered by direct examination of indices in each external corrosion direct assessment region, indicates a need for reassessment of the covered segment at an interval less than that specified in paragraph 14.146 to 14.157.

Requirements for using internal corrosion direct assessment

Internal corrosion direct assessment

14.73 Internal corrosion direct assessment is a process an operator uses to identify any area along a pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside.

14.74 The process identifies the potential for internal corrosion caused by micro-organisms, fluid with carbon dioxide, oxygen, hydrogen sulphide or other contaminant present in the gas.

General requirements to address internal corrosion

14.75 An operator that uses direct assessment as an assessment method to address internal corrosion in a covered pipeline segment shall comply with the requirements in this Schedule.

14.76 The internal corrosion direct assessment applies only to a segment of pipe that transports nominally dry natural gas, and not a segment with electrolyte nominally present in the gas stream.

14.77 If an operator uses internal corrosion direct assessment to assess a covered segment operating with electrolyte present in the gas stream, the operator shall develop a plan which demonstrates how it will conduct internal corrosion direct assessment in the segment to effectively address internal corrosion, and provide notification in accordance with paragraph 14.52(d) or paragraph 14.144.

The internal corrosion direct assessment plan

14.78 An operator shall develop and follow an internal corrosion direct assessment plan which provides for pre-assessment, identification of the internal corrosion direct assessment region and excavation locations, the detailed examination of pipes at excavation locations and post-assessment evaluation and monitoring.

Pre-assessment

14.79 In the pre-assessment stage, an operator shall gather and integrate data and information required to evaluate the feasibility of internal corrosion direct assessment for a covered segment, and support use of a model to identify

(a) the location along the pipe segment where electrolyte may accumulate;

(b) an internal corrosion direct assessment region, and

(c) any area within a covered segment where liquid may potentially be entrained.

14.80 The data and information shall include

(a) the data elements specified in the Fifteenth Schedule,

(b) the information needed to support the use of a model that an operator shall use to identify any area along a pipeline where internal corrosion is most likely to occur, including

(i) the location of every gas input sag, drip, incline, valve, manifold, dead-leg and trap,

(ii) the elevation profile of the pipeline in sufficient detail that an angle of inclination can be calculated for every pipe segment,

(iii) the diameter of pipeline, and

(iv) the range of expected gas velocity in the pipeline;

(c) operating experience data which shall indicate the historic upset in a gas condition location where the upset has occurred and potential damage had resulted from the upset condition; and

(d) information on any covered segment where a cleaning pig may

(i) not have been used, or

(ii) deposit electrolyte.

Internal corrosion direct assessment region identification

14.81 An operator's plan shall identify where every internal corrosion direct assessment region is located in the transmission system, in which a covered segment is located.

14.82 An internal corrosion direct assessment region shall extend from the location where the liquid may first enter the pipeline and encompass the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed.

14.83 An internal corrosion direct assessment region may encompass one or more covered segments.

14.84 In the identification process, an operator shall use

(a) the model specified in the Fifteenth Schedule; or

(b) another model if the operator demonstrates its equivalent to the model specified in the Fifteenth Schedule.

14.85 An operator shall take into consideration

(a) changes in pipe diameter,

(b) the location where gas enters a line with potential to introduce liquid, and

(c) the location down stream of gas draw-offs, where gas velocity is reduced, to define a critical pipe angle of inclination above which water film cannot be transported by gas,

in choosing the model.

Identification of location for excavation and direct examination

14.8 An operator's plan shall identify the location where internal corrosion is most likely to occur in each internal corrosion direct assessment region.

14.87 In the location identification process, the operator shall

(a) identify a minimum of two locations for excavation within each internal corrosion direct assessment region within a covered segment, and

(b) perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or any other generally accepted measurement technique.

14.88 One location for excavation and direct examination shall be the low point such as a sag, drip, valve, manifold, dead-leg or trap within the covered segment nearest to the beginning of the internal corrosion direct assessment region.

14.89 The second location shall be further downstream, within a covered segment, near the end of the internal corrosion direct assessment region.

14.90 If corrosion exists at either location, the operator shall

(a) as part of the operator's integrity assessment either perform additional excavation in each covered segment within the assessment method permitted in this Schedule to assess the pipeline in each covered segment within the internal corrosion direct assessment region for internal corrosion,

(b) evaluate the potential for internal corrosion in every pipeline segment, both covered and non-covered, in the operator's pipeline system with similar characteristics to the internal corrosion direct assessment region that contains the covered segment in which the corrosion was found, and

(c) remedy the conditions the operator finds in accordance with paragraph 14.104 to 14.121.

Post-assessment evaluation and monitoring

14.91 An operator's plan shall provide for the evaluation of the effectiveness of the internal corrosion direct assessment process and continued monitoring of covered segments where internal corrosion has been identified.

14.92 The evaluation and monitoring process includes

(a) evaluation of the effectiveness of the internal corrosion direct assessment as an assessment method to address internal corrosion and the determination of whether a covered segment should be reassessed at a more frequent interval than that specified in paragraph 14.146 to 14.157 and the operator must carry out the evaluation within a year of the conduct of the internal corrosion direct assessment, and

(b) continuous monitoring of each covered segment where internal corrosion has been identified by the use of the technique of coupon, ultrasonic ceiling sensors or electronic probe, with the periodic draw off of liquid at low points and chemically analyse the liquid for the presence of any corrosion product.

14.93 An operator shall base the frequency of the monitoring and liquid analysis on the result from each integrity assessment that has been conducted in accordance with the requirements of this Schedule, and the risk factors related to the covered segment.

14.94 If the operator finds any evidence of a corrosion product in the covered segment, the operator shall take prompt action in accordance with one of the following required actions and remedy the condition that the operator has discovered in accordance with paragraph 14.104 to 14.121:

(a) conduct an excavation of a covered segment at a location downstream from where the electrolyte might have entered the pipe; or

(b) assess the covered segment with the use of another integrity assessment method provided in this Schedule.

Other requirements

14.95 The internal corrosion direct assessment plan shall include

(a) the criteria an operator is required to apply to make a key decision in respect of the internal corrosion direct assessment feasibility, the delineation of an internal corrosion direct assessment region and the prescription of a condition that requires excavation for the implementation of each stage of the internal corrosion direct assessment process;

(b) provision for the application of a more restrictive criteria during the conduct of an internal corrosion direct assessment for the first time on a covered segment and that becomes less stringent as the operator gains experience; and

(c) provision for analysis to be carried out on the entire pipeline in which a covered segment is present, except that an application of the remediation criteria under paragraph 14.104 to 14.121 shall be limited to a covered segment.

Requirements for the use of direct assessment for stress corrosion cracking

General requirements

14.96 An operator that uses direct assessment as an integrity assessment method to address stress corrosion cracking in a covered segment, shall have a plan that includes

(a) a systematic process to collect and evaluate data for every covered segment to identify whether the condition for stress corrosion cracking is present in respect of data gathering and integration, and

(b) a procedure to prioritise the covered segment for assessment in respect of

(i) gathering data related to each site the operator excavates during the conduct of pipeline operation where the criteria specified in the Fifteenth Schedule indicates the potential for stress corrosion cracking;

(ii) at a minimum, the data specified in the Fifteenth Schedule; and

(c) an assessment method for the condition of stress corrosion cracking is identified in a covered segment.

14.97 The operator shall assess the covered segment under paragraph 14.96 by an integrity assessment method specified in the Fifteenth Schedule and remedy the threat in accordance with the requirements provided in the Fifteenth Schedule.

Confirmatory direct assessment

14.98 An operator that uses the confirmatory direct assessment method under paragraph 14.134 to 14.145 shall have a plan which meets the requirements of paragraph 14.64 to 14.72 and paragraph 14.73 to 14.95

Threats

14.99 An operator shall only use confirmatory direct assessment on a covered segment to identify damage that results from external corrosion or internal corrosion.

External corrosion plan

14.100 An operator's confirmatory direct assessment plan for identification of external corrosion, shall meet the requirements of paragraph 14.64 to 14.72, except where

(a) the procedure for indirect examination permits the use of only one indirect examination tool suitable for the application;

(b) the procedures for direct examination and remediation provide that

(i) every immediate action indication shall be excavated for each external corrosion direct assessment region and

(ii) at least one high risk indication that meets the criteria of scheduled action shall be excavated in each external corrosion direct assessment region.

Internal corrosion plan

14.101 An operator's confirmatory direct assessment plan for identification of internal corrosion shall comply with paragraph 14.73 to 14.95 except that the procedure for the identification of location for an excavation, may require the excavation of only one high risk location in each internal corrosion direct assessment region.

Defects requiring near-term remedy

14.102 If any assessment carried out under paragraph 14.100 or 14.101 reveals any defect that requires remedy before the next scheduled assessment, the operator responsible, shall schedule the next assessment in accordance with the requirements provided in the Fifteenth Schedule.

14.103 If a defect requires immediate remedy, the operator shall reduce pressure consistent with paragraph 14.104 to 14.121 until the operator has completed reassessment by any of the assessment techniques under paragraph 14.134 to 14.145.

Actions to address integrity conditions

General requirements

14.104 An operator all take prompt action to address every anomalous condition that the operator discovers through an integrity assessment.

14.105 The operator shall evaluate each anomalous condition and remedy that is likely to reduce a pipeline's integrity.

14.106 An operator shall demonstrate that the remedy of the condition is unlikely to pose a threat to the integrity of the pipeline until the next assessment of the covered segment.

14.107 Where an operator is unable to respond within the time limit for a certain condition specified in this Schedule, that operator shall temporarily reduce the operating pressure of the pipeline or take any other action to ensure the safety of the covered segment.

14.108 If pressure is reduced, the operator shall determine the temporary reduction in pressure by the method specified in the Fifteenth Schedule or reduce the operating pressure to a level of not more than 80% of the level at the time the condition was discovered.

14.109 A reduction in operating pressure shall not exceed three hundred and sixty-five days without the operator's provision of the technical justification that the continued pressure reduction will not jeopardise the integrity of the pipeline.

Discovery of condition

14.110 The discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline.

14.111 A condition that presents a potential threat includes a condition that requires a remedy or needs to be monitored under paragraph 14.113 to 14.121.

14.112 An operator shall promptly, but no later than one hundred and eighty days after the conduct of an integrity assessment, obtain sufficient information about a condition to make the determination, unless the operator demonstrates that the period is impracticable.

Schedule for evaluation and remediation

14.113 An operator shall complete the remediation of a condition in accordance with a Schedule that prioritises the conditions for evaluation and remediation.

14.114 Unless a special requirement for remediation of a certain condition applies, as provided under paragraph 14.117 to 14.121 an operator shall follow the procedure provided in the Fifteenth Schedule.

14.115 If an operator cannot comply with the requirements specified in the Schedule in respect of any condition, the operator shall justify that fact with a reason for the non-compliance and indicate how the changed schedule will not jeopardise public safety

14.116 An operator shall notify the Commission if that operator cannot comply with the requirements contained in this Schedule and cannot provide safe through a temporary reduction in operating pressure or other action.

14.117 An operator's evaluation and remediation schedule shall accord with the conditions specified in the Fifteenth Schedule to provide for immediate repair conditions.

14.118 The operator shall temporarily reduce operating pressure in accordance with paragraph 14.104 to 14.109 or shut down the pipeline until the operator completes the repair of conditions to maintain safety.

14.119 An operator shall treat the following as immediate repair conditions:

(a) a calculation of the remainder of strength of the pipe which shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly;

(b) a dent that has an indication of metal loss, cracking or a stress riser; or

(c) an indication or anomaly that in the judgement of the person designated by the operator to evaluate the assessment results, requires immediate action.

One year condition

14.120 Subject to the requirements of this Schedule, an operator shall remedy any of the following within one year of discovery of the condition:

(a) a smooth dent located between the 8 o'clock and 4 o'clock positions that is the upper two-thirds of the pipe with a depth greater than 6% of the pipeline diameter and greater than 6.35 millimetres in depth for a pipeline diameter less than the nominal pipe size of 304.80 millimetres; or

(b) a dent with a depth greater than 2% of the pipeline diameter, 6.35 millimeters in depth for a pipeline diameter of less than nominal pipe size of 304.80 millimetres that affects pipe curvature at a girth weld or at a longitudinal seam weld.

Monitored condition

14.121 An operator is not required to have a schedule for the following conditions for remediation:

(a) a dent with a depth greater than 6% of pipeline diameter and greater than 12.70 millimetres in depth for a pipeline diameter less than the nominal pipe size of 304.80 millimetres, located between the 4 o'clock position and the 8 o'clock position that is the bottom one-third of the pipe;

(b) a dent located between the 8 o'clock and 4 o'clock positions that is the upper two-thirds of pipe, with a depth greater than 6% of the pipeline diameter and greater than 12.70 millimetres depth or a pipeline diameter less than the nominal pipe size of 304.80, with an engineering analysis of the dent that demonstrates that the critical strain level is not exceeded, and

(c) a dent with a depth greater than 2% of the pipeline diameter, 6.35 millimetres in depth for a pipeline diameter less than the nominal pipe size of 304.80 millimetres, that affects pipe curvature at a girth weld or at a longitudinal seam weld, with an engineering analysis of the dent and girth or seam weld that demonstrates that the critical strain level is not exceeded, if the analysis takes into consideration weld properties

except that the operator shall record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation.

Additional preventive and mitigative measures

General requirements

14.122 An operator shall conduct, in accordance with one of the risk assessment approaches specified in the Fifteenth Schedule, a risk analysis of its pipeline to identify any additional measure to protect the high consequence area and enhance public safety.

14.123 An operator shall base the additional measure on the threat the operator has identified in respect of each pipeline segment.

14.124 The additional measures include the

(a) installation of an automatic valve,

(b) installation of a computerised monitoring and leak detection system,

(c) replacement of pipe segment with pipe of heavier wall thickness,

(d) provision of additional training to personnel on response procedures;

(e) conduct of drills with local emergency responders; and

(f) implementation of additional inspection and maintenance programmes.

Third party damage

14.125 An operator shall enhance its damage prevention programme to include

(a) the use of qualified personnel for work that an operator conducts and that could adversely affect the integrity of a covered segment, like marking, location and direct supervision of known excavation; and

(b) monitoring of excavation conducted on a covered pipeline segment by pipeline personnel.

14.126 If an operator finds physical evidence of encroachment involving excavation that, that operator did not monitor near a covered segment.

(a) the operator shall excavate the area near the encroachment or conduct an above ground survey by any of the methods provided in the Fifteenth Schedule; and

(b) the operator shall excavate and remediate in accordance with the requirements specified in the Fifteenth Schedule and paragraph 14.104 to 14.121 in respect of any indication of coating holiday or discontinuity warrants direct examination.

Outside force damage

14.127 If an operator determines that outside force like earth movement, flood, or an unstable suspension bridge, is a threat to the integrity of a covered segment, that operator shall take the necessary measures to minimise the consequence to the covered segment from the outside force damage.

14.128 The measures to be taken shall include the increase of the frequency of aerial, foot or other method of patrol, additional external protection, reduction of external stress, and the relocation of the pipeline.

Automatic shut-off valves or remote control valve

14.129 Where an operator determines, based on a risk analysis, that an automatic shut-off valve or remote control valve is an efficient means to add protection to a high consequence area in the event of a gas release, the operator shall install the respective valve.

14.130 The operator shall consider

(a) swiftness of leak and pipe shut down capability,

(b) the type of gas being transported,

(c) the operating pressure,

(d) the rate of potential release,

(e) pipeline profile,

(f) the potential for ignition, and

(g) the location of the nearest response personnel in making the determination.

Pipelines operating below 30% specified minimum yield strength

14.131 An operator of a transmission pipeline that operates below 30% of the specified minimum yield strength located in a high consequence area shall comply with the requirements of this Schedule.

14.132 Without limiting the effect of paragraph 14.131 and subparagraph (c), the operator of a transmission pipeline that operates below 30% of the specified minimum yield strength located in a high consequence area shall comply with the following:

(a) in a Class 3 or Class 4 area outside a high consequence area follow the requirements of this section;

(b) apply the requirements in paragraph 14.125 (a) and paragraph 11.18 to the pipeline; and

(c) perform a semi-annual leak survey generally but quarterly for an unprotected pipeline or cathodically protected pipe where an electrical survey is impractical.

Plastic transmission pipeline

14.133 An operator of a plastic transmission pipeline shall apply the requirements in paragraph 14.125 and 14.126 to the covered segment of a pipeline.

Continual process of evaluation and assessment to maintain pipeline integrity

General requirements

14.134 After completion of the baseline integrity assessment of a covered segment, an operator shall continue to assess the pipeline of that segment at the intervals specified in paragraph 14.146 to 14.157 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph 14.136 to 14.140.

14.135 An operator shall reassess a covered segment on which a baseline assessment is conducted no later than seven years after the baseline assessment of that covered segment, unless the evaluation under paragraph 14.136 to 14.140 warrants an earlier reassessment.

Evaluation

14.136 An operator shall conduct a periodic evaluation as frequently as necessary to assure the integrity of each covered segment.

14.137 The periodic evaluation shall be based on the data integration and risk assessment of the entire pipeline as specified in paragraph 14.28 to 14.49.

14.138 In the case of a plastic transmission pipeline, the periodic evaluation shall be based on the threat analysis specified in paragraph 14.33.

14.139 In the case of any other transmission pipeline, the evaluation shall take into consideration the past and present integrity assessment results, data integration and risk assessment information of any decision about remediation and additional preventive and mitigative actions.

14.140 The operator shall use the result from an evaluation to identify the threat specific to each covered segment and the risk represented by any of these threats.

Assessment methods

14.141 In the conduct of integrity reassessment, an operator shall assess the integrity of the pipeline in the covered segment by

(a) any of the methods used for the detection of a threat to which the covered segment is susceptible,

(b) confirmatory direct assessment under the conditions specified in paragraph 14.98 to 14.103.

14.142 An operator shall follow the method specified in the Fifteenth Schedule for the selection of the appropriate internal inspection tool for a covered segment in respect of the use of an internal tool capable of detection of corrosion, and any other threat to which the covered segment is susceptible.

14.143 An operator shall use the test pressure specified in the Fifteenth Schedule to justify an extended reassessment interval respect of a pressure test conducted in accordance with the ninth schedule.

14.144 An operator shall in making a choice to use other technology, demonstrate that that operator can provide an equivalent understanding of the condition of the pipeline and shall inform the Commission one hundred and eighty days before the conduct of the assessment.

14.145 An operator that uses confirmatory direct assessment on a covered segment which is scheduled for reassessment for a period longer than seven years, shall comply with paragraph 14.98 to 14.103.

Required reassessment intervals

14.146 An operator that comply with the requirements under paragraph 14.147 to 14.157 to establish the reassessment interval for the operator's covered pipeline segment.

Pipeline operating at or above the 30% specified minimum yield strength

14.147 Subject to the requirements of this Schedule, the maximum reassessment interval by an allowable reassessment method is seven years.

14.148 If an operator establishes a reassessment interval that exceeds seven years, that operator shall, within the seven year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established.

14.149 A reassessment carried out by the confirmatory direct assessment method shall be done in accordance with paragraph 14.98 to 14.103.

Pressure test, internal inspection or other equivalent technology

14.150 An operator that uses pressure testing or internal inspection as an assessment method shall establish the reassessment interval for the covered pipeline segment by

(a) basing the interval on the identified threat for the covered segment and on the analysis of the result from the last integrity assessment and from data integration and risk assessment required under paragraph 14.28 to 14.49; and

(b) the use of the intervals specified for different stress levels of pipeline that operate at or above 30% the specified minimum yield strength as provided in the Fifteenth Schedule.

External corrosion direct assessment

14.151 An operator that uses external corrosion direct assessment that meets the requirements of this Schedule shall determine the reassessment interval according to the requirements specified in the Fifteenth Schedule.

Internal corrosion or stress corrosion cracking direct assessment

14.152 An operator that uses internal corrosion direct assessment or stress corrosion cracking direct assessment in accordance with the requirements of this Schedule shall determine the reassessment interval in accordance with the following methods:

(a) determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection condition;

(b) use the largest remaining defect as the size of the largest defect discovered in the stress corrosion cracking or the internal corrosion direct assessment segment; and

(c) estimate the reassessment interval as half the time required for the largest defect to grow to a critical size except that the reassessment interval shall not exceed the interval specified in the Fifteenth Schedule.

Establishment of measurement interval for a covered pipeline segment

4.153 The maximum reassessment interval by an allowable reassessment method is seven years.

14.154 An operator shall establish reassessment by at least one of the following methods:

(a) reassessment by pressure test, internal inspection or other equivalent technology in accordance with paragraph 14.150;

(b) reassessment by external corrosion direct assessment pursuant to paragraph 14.151;

(c) reassessment by internal corrosion direct assessment or stress corrosion cracking direct assessment pursuant to paragraph 14.152; and

Assessment method Pipeline operating at or above 50% specified minimum yield strength Pipeline operating at or above 30% specified minimum yield strength, up to 50% specified minimum yield strength Pipeline operating below 30% specified minimum yield strength

Internal inspection tool, pressure test or direct assessment

10 years (*)

15 years (*)

20 years (**)

Confirmatory direct assessment 7 years 7 years 7 years

Low stress reassessment Not applicable Not applicable 7 years + ongoing actions specified in paragraph 14.158 to 14.164

(d) reassessment by confirmatory direct assessment at seven - year intervals in accordance with paragraphs 14.98 to 14.103, with reassessment by one of the methods listed in this Schedule by the twentieth year of the interval.

14.155 Despite paragraph 14.150 (b), the stress level shall be adjusted to reflect the lower operating stress level and where the interval is more than seven years, the operator shall conduct by the seventh year of the interval, a confirmatory direct assessment in accordance with paragraph 14.98 to 14.103 or low stress reassessment in accordance with paragraph 14.158 to 14.164.

14.156 Reference may be made to Part C of the Fifteenth Schedule for guidance on the assessment methods and assessment schedule for the transmission of pipelines that operate below 30% specified minimum yield strength and in case of conflict, the requirement in this Schedule shall prevail.

14.157 The table below sets forth the maximum reassessment intervals and an operator shall comply with the correlative requirements for the purpose of the establishment of a reassessment interval, for a covered segment:

(*) A confirmatory direct assessment as described in paragraphs 14.98 to 14.103 shall be conducted by the seventh year in every ten year interval and the fourteenth year in a fifteen year interval.

(**) A low stress reassessment or confirmatory direct assessment shall be conducted by the seventh year and fourteenth year of the two intervals.

Low stress reassessment

General

14.158 An operator of a transmission line that operates below 30% of the specified minimum yield strength may use the methods in this Schedule to reassess a covered segment in accordance with paragraph 14.146 to 14.157.

14.159 The internal low stress reassessment method shall address the threat of external corrosion.

14.160 The operator shall conduct a baseline assessment of the covered segment in accordance with paragraph 14.50 to 14.63.

External corrosion

14.161 An operator shall take anyone of the following actions to address external corrosion on a low stress covered segment and the threat of external corrosion on a cathodically protected pipe in a covered segment:

(a) perform an electrical survey or indirect examination tool method on the covered segment at least every seven years, and

(b) use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment.

14.162 The evaluation shall take into account at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records and the pipeline environment.

Unprotected pipe or catholically protected pipe where electrical surveys are impractical

14.163 If an electrical survey is impractical on the covered segment, an operator shall

(a) conduct a leakage survey as required by paragraphs 12.7 to 12.8 of the Twelfth Schedule at four-month intervals; and

(b) identify and remediate any area of active corrosion by the evaluation of the leak repair and inspection record, corrosion monitoring record, exposed pipe inspection record and the pipeline environment every eighteen months.

Internal corrosion

14.164 To address the threat of internal corrosion on a covered segment, an operator shall

(a) conduct a gas analysis for corrosive agents at least once each year,

(b) conduct periodic testing of fluid removed from the segment,

(c) test at least once each year the fluid removed from each storage field that may affect a covered segment, and

(d) integrate data from analysis and testing required by sub-paragraphs (a),(b) and (c) with the applicable internal corrosion leak record, incident report, safety-related condition report, repair record, patrol record, exposed pipe reports, test report and define and implement the appropriate remediation actions at least every seven years.

Deviation from reassessment intervals

Waiver from reassessment intervals in limited circumstances

14.165 The Commission may permit a waiver from reassessment of an interval required under paragraph 14.146 to 14.157 if the Commission finds that the waiver would not be inconsistent with pipeline safety.

Lack of internal inspection tools

14.166 An operator that uses internal inspection as an assessment method, may be granted a waiver by the Commission if that operator is able to justify a longer reassessment period for a covered segment where an internal inspection tool is not available to assess the line pipe.

14.167 An operator shall justify a longer reassessment if that operator can demonstrate that the internal corrosion tool cannot be obtained within the required reassessment period and that the actions the operator is to take in the interim, would ensure the integrity of the covered segment.

Maintain product supply

14.168 An operator may be able to justify a longer reassessment period for a covered segment if that operator demonstrates that the local product supply cannot be maintained if the reassessment is conducted within the required interval.

Application for waiver

14.169 An operator may apply to the Commission for a waiver of the required reassessment interval if one of the conditions specified in paragraph 14.161 to 14.163 applies.

14.170 The operator shall apply for the waiver in the manner specified by the Commission at least one hundred and eighty days before the end of the required reassessment interval, unless local product supply makes the period impractical.

14.171 If local product supply makes the period impractical, the operator shall apply for the waiver as soon as the need for the waiver becomes known.

Measurement of programme effectiveness

General requirements

14.172 An operator shall include in its integrity management programme, methods to measure, on a semi-annual basis, whether the programme is effective in the assessment and evaluation of the integrity of each covered pipeline segment and in the protection of the high consequence area.

14.173 The measures shall include the four overall performance measures in accordance with the requirements specified in the Fifteenth Schedule and the specific measures for each identified threat specified in the same.

14.174 The operator shall submit to the Commission the report on the four overall performance measures, by electronic or other means, every six months.

External corrosion direct assessment

14.175 In addition to the general requirements for the performance measures in paragraph 14.172 to 14.174, an operator that uses direct assessment to assess the external corrosion threat, shall define and monitor measures to determine the effectiveness of the external corrosion direct assessment process. These measures shall meet the requirements specified under paragraphs 14.64 to 14.72.

Operator records

14.176 An operator, shall maintain the following records for review during an inspection:

(a) a written integrity management programme in accordance with paragraph 14.10 to 14.15;

(b) documents to support the threat identification and risk assessment in accordance with paragraph 14.28 to 14.49;

(c) a written baseline assessment plan in accordance with paragraph 14.50 to 14.51

(d) documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management programme, including documents developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate the programme elements;

(e) documents that demonstrate that personnel have the required training, including a description of the training programme, in accordance with paragraph 14.24 to 14.27;

(f) the schedule required under paragraph 14.104 to 14.121 that prioritises the conditions deleted during an assessment for evaluation and remediation, including technical justifications for the schedule;

(g) documents required to carry out the requirements of paragraph 14.61 to 14.97 for a direct assessment plan;

(h) documents to carry out the requirements of paragraph 14.98 to 14.103 or confirmatory direct assessment; and

(i) verification that an operator has provided the documentation or notification required in this Schedule to be provided to the Commission.

Interpretation

14.177 In this Schedule, unless the context otherwise requires,

“cleaning pig” means a device that is inserted into and moves through the interior of a pipeline for cleaning without stopping the flow of gas in the pipeline;

“coating holiday” means a discontinuity or break in the anti-corrosion coating on pipe or tubing that leaves the bare metal exposed to corrosive processes;

“construction defect” means an imperfection or damage caused by the improper conduct or omission on the part of a builder or the failure of the design during construction or repair of a pipeline;

“cyclic fatigue” means the weakening of a material caused by the repeated application and removal of stress;

“dead-leg” means a section of a pipeline that is not in use;

“dent” means a depression in the pipeline surface caused by pressure or a blow;

“electronic probe” means a device used to measure electron temperatures, ion densities, space and wall potentials and random electron current in a plasma;

“electric resistance-welded pipe” means a pipe produced from a flat piece of steel of which the edges are rolled together to create a tube or pipe and then connected or fused together utilising a method in which the two edges of a curved plate of metal are heated by passing an electric current through them;

“engineering analysis” means a scientific method for assessment used to maintain pipeline integrity;

“foreign line crossing” means any utility line other than the natural gas pipeline that has been constructed close to or on the right of way;

“gas draw-off” means the discharge of gas through a pressure reduction vent or valve;

“gouge” means [sic] means a cut or groove as left by something sharp;

“high consequence area” means an area established by one of the following methods:

(i) an area defined as

(a) a Class 3 location under regulation 1.6 (c)

(b) a Class 4 location under regulation 1.6 (d), or

(c) any area in a Class 1 or Class 2 location where the potential impact radius is greater than 201.17 metres, and the area within a potential impact circle contains twenty or more buildings intended for human occupancy, or

(d) any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site,

(ii) the area within a potential impact circle that contains

(a) twenty or more buildings intended for human occupancy, or

(b) an identified site;

“identified site” means each of the following areas:

(i) an outside area or open structure which is occupied by twenty or more persons on at least fifty days in any twelve-month period examples of which include beaches, playgrounds, recreational facilities, outdoor theatres, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(ii) a building which is occupied by twenty or more persons on at least five days a week for ten weeks in a twelve-month period examples of which include to religious facilities, office buildings, community centres, or general stores, or

(iii) a facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate like hospitals, prisons, schools or day care facilities,

“input sag” means a concave bend in the pipeline;

“internal corrosion” means the deterioration of the internal wall of a natural gas pipeline due to the exposure to water and contaminants in the gas;

“lap welded pipe” means a pipe made by welding along a scarfed in which one part is overlapped by another;

“longitudinal seam weld” means a series of overlapping spot welds along the axis of a pipe;

“metal loss” means a type of anomaly in a pipe in which metal has been removed from the pipe surface usually due to corrosion or gouging;

“outside force damage” means a damage to a pipeline resulting from an external force acting on it such as from excavation activities;

“potential impact radius (PIR)” means the radius of a circle with which the potential failure of a pipeline could have significant impact on people or property.

PIR is determined by the formula:

R = 0.69* (square root of (p*d2)),

where:

‘r’ is the radius of a circular area in feet surrounding the point of failure,

‘p’ is the maximum allowable operating pressure maximum allowable operating pressure in pipeline segment in pounds per square inch, and

‘d’ is the normal diameter of the pipeline in inches.

Note: 0.69 is the factor for natural gas.

“remediation” means a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

“seam” means the line of union or joint of two metal plates;

“seam corrosion anomaly” means a deviation or irregularity in the consistency and quality of a seam as a result of corrosion;

“seam integrity” means consistency and soundness of the quality of the joint;

“strain level” means the degree of deformation produced by stress;

“stress corrosion cracking” means cracking that occurs in a steel pipe material that is caused by a combination of stress, corrosive environment and temperature;

“stress riser” means a geometric irregularity that breaks the uniformity of the material;

“time dependent” means changes in value with time;

“third party damage” means a damage caused by a person other than the operator or the employees or agents of the operator;

“urgency level” means the degree of importance of notification or undertaking an action; and

“ultrasonic ceiling sensor” is a device which evaluates the attributes of an object by interpreting the echoes from radio or sound waves emitted by the object.

FIFTEENTH SCHEDULE

PART A

OIL AND GAS INDUSTRY STANDARDS ESTABLISHED BY THE STANDARDS AUTHORITY

NO. Paragraph STD REF NO TITLE

1. GS ISO/TR 10400:2007 Petroleum and natural gas industries — Equations and calculations for the properties of casing, tubing, drill pipe and line pipe used as casing or tubing.

2. GS ISO 10407-2:2008 Petroleum and natural gas industries— Rotary drilling equipment— Part 2: Inspection and classification of used drill stem elements.

3. GS ISO 10407-2:2008

Cor. 1:2009 Petroleum and natural gas industries— Rotary drilling equipment— Part 2: Inspection and classification of used drill stem elements. TECHNICAL CORRIGENDUM 1.

4. GS ISO 10414-1:2008 Petroleum and natural gas industries— Field testing of drilling fluids— Part 1: Water-based fluids.

5. GS ISO 10414- 1:2002 Petroleum and natural gas industries— Field testing of drilling fluids— Part 2: Oil-based fluids.

6. GS ISO 10416:2008 Petroleum and natural gas industries— Drilling fluids— Laboratory testing.

7. GS ISO 10417:2004 Petroleum and natural gas industries— Subsurface safety valve systems— Design, installation, operation and redress.

8. GS ISO 10418:2003 Petroleum and natural gas industries— Offshore production installations— Analysis, design, installation and testing of basic surface process safety systems.

9. GS ISO 10418:2003/Cor. 1:2008 Petroleum and natural gas industries—Offshore production installations—Analysis, design, installation and testing of basic surface process safety systems. TECHNICAL CORRIGENDUM 1.

10. GS ISO 10423:2009 Petroleum and natural gas industries — Drilling and production equipment — Wellhead ad Christmas tree equipment.

11. GS ISO 10424-1:2004 Petroleum and natural gas industries— Rotary drilling equipment— Part 1: Rotary drill stem elements.

12. GS ISO 10424-2:2007 Petroleum and natural gas industries — Rotary drilling equipment —Part 2: Threading and gauging of rotary shouldered thread connections.

13. GS ISO 10426-1:2009 Petroleum and natural gas industries — Cements and materials for well cementing — Part 1: Specification

14. GS ISO 10426-2:2003 Petroleum and natural gas industries — Cements and materials for well cementing — Part 2: Testing of well cements.

15. GS ISO 10426-2:2003/Cor.1:2006 Petroleum and natural gas industries — Cements and materials for well cementing — Part 2: Testing of well cements. TECHNICAL CORRIGENDUM 1.

16. GS ISO 10426-2:2003/Amd. 1:2005 Petroleum and natural gas industries — Cements and materials for well cementing — Part 2: Testing of well cements. AMENDMENT 1: Water-wetting capability testing.

17. GS ISO 10426-3:2003 Petroleum and natural gas industries — Cements and materials for well cementing — Part 3: Testing of deepwater well cement formulations

18. GS ISO 10426-4:2004 Petroleum and natural gas industries — Cements and materials for well cementing — Part 4: Preparation and testing of foamed cement slurries at atmospheric pressure.

19. GS ISO 10426-5:2004 Petroleum and natural gas industries — Cements and materials for well cementing — Part 5: Determination of shrinkage and expansion of well cement formulations at atmospheric pressure.

20. GS ISO 10426-6:2008 Petroleum and natural gas industries — Cements and materials for well cementing — Part 6: Methods for determining the static gel strength of cement formulations.

21. GS ISO 10427-1:2001 Petroleum and natural gas industries — Equipment for well cementing — Part 1: Casing bow-spring centralizers.

22. GS ISO 10427-2:2004 Petroleum and natural gas industries — Equipment for well cementing — Part 2: Centralizer placement and stop-collar testing

23. GS ISO 10427-3: 2003 Petroleum and natural gas industries —Equipment for well cementing — Part 3: Performance testing of cementing float equipment

24. GS ISO 10432:2004 Petroleum and natural gas industries — Downhole equipment — Subsurface safety valve equipment.

25. GS ISO 10437:2003 Petroleum, petrochemical and natural gas industries — Steam turbines — Special-purpose applications.

26. GS ISO 10438-1:2007 Petroleum, petrochemical and natural gas industries — Lubrication, shaft-sealing and control-oil systems and auxiliaries — Part 1: General requirements.

27. GS ISO 10438-2:2007 Petroleum, petrochemical and natural gas industries — Lubrication, shaft-sealing and control-oil systems and auxiliaries — Part 2: Special-purpose oil systems.

28. GS ISO 10438-3:2007 Petroleum, petrochemical and natural gas industries — Lubrication, shaft-sealing and control-oil systems and auxiliaries — Part 3: General-purpose oil system.

29. GS ISO 10438-4:2007 Petroleum, petrochemical and natural gas industries — Lubrication, shaft-sealing and control-oil systems and auxiliaries — Part 4: Self-acting gas seal support systems.

30. GS ISO 10441:2007 Petroleum, petrochemical and natural gas industries — Flexible couplings for mechanical power transmission — Special-purpose applications.

31. Par. 1.3, 1.5, 1.9, 1.10(a), 1.11(a), 2.6 GS ISO 11960:2004 Petroleum and Natural Gas Industries-Steel pipes for use as casing or tubing for wells.

32. Par.1.3, 1.5, 1.9, 1.10(a), 1.11(a) GS ISO 11960:2004/Cor, 1:2006 Petroleum and Natural Gas Industries-Steel pipes for use as casing or tubing for wells. TECHNICAL CORRIGENDUM 1.

33. GS ISO 11961:2008 Petroleum and natural gas industries – Steel drill pipe.

34. GS ISO 11961:2008/Cor. 1:2009 Petroleum and natural gas industries –Steel drill pipe. TECHNICAL CORRIGENDUM 1.

35. GS ISO 13500:2008 Petroleum and natural gas industries — Drilling fluid materials — Specifications and tests.

36. GS ISO 13500:2008/Cor 1:2009 Petroleum and Natural gas industries — Drilling fluid materials — Specifications and tests. TECHNICAL CORRIGENDUM 1.

37. GS ISO 13501:2005 Petroleum and natural gas industries — Drilling fluids — Processing systems evaluation

38. GS ISO 13503-1:2003 Petroleum and natural gas industries — Completion fluids and materials — Part 1: Measurement of viscous properties of completion fluids

39. GS ISO 13503-2:2006 Petroleum and natural gas industries —Completion fluids and materials — Part 2: Measurement of properties of proppants used in hydraulic fracturing and gravel-packing operations

40. GS ISO 13503-2:2006/Amd. 1:2009 Petroleum and natural gas industries — Completion fluids and materials — Part 2: Measurement of properties of proppants used in hydraulic fracturing and gravel-packing operations. AMENDMENT 1: Addition of Annex B: Proppant specification

41. GS ISO 13503-3:2005 Petroleum and natural gas industries — Completion fluids and materials — Part 3: Testing of heavy brines

42. GS ISO 13503-3:2005/Cor. 1:2006 Petroleum and natural gas industries — Completion fluids and materials — Part 3: Testing of heavy brines. TECHNICAL CORRIGENDUM 1

43. GS ISO 13503-4:2006 Petroleum and natural gas industries — Completion fluids and materials — Part 4: Procedure for measuring stimulation and gravel-pack fluid leak off under static conditions

44. GS ISO 13503-5:2006 Petroleum and natural gas industries — Completion fluids and materials — Part 5: Procedures for measuring the long-term conductivity of proppants

45. GS ISO 13533:2001 Petroleum and natural gas industries — Drilling and production equipment – Drill-through equipment

46. GS ISO 13533:2001/Cor. 1:2005 Petroleum and natural gas industries — Drilling and production equipment – Drill-through equipment. TECHNICAL CORRIGENDUM 1

47. GS ISO 13534:2000 Petroleum and natural gas industries — Drilling and production equipment — Inspection, maintenance, repair and remanufacture of hoisting equipment

48. GS ISO 13535: 2000 Petroleum and natural gas industries — Drilling and production equipment — Hoisting equipment

49. Par. 1.16, 3.27, 3.28(b), 3.30, 3.4, 3.4(b), 4.13, 11.26 to 11.28, 12.30 GS ISO 13623:2009 Petroleum and natural gas industries — Pipeline transportation systems

50. GS ISO 13624-1:2009 Petroleum and natural gas industries — Part 1: Design and operation of marine drilling riser equipment.

51. GS ISO/TR 13624-2:2009 Petroleum and natural gas industries — Drilling and production equipment — Part 2: Deepwater drilling riser methodologies, operations, and integrity technical report.

52. GS ISO 13625:2002 Petroleum and natural gas industries — Drilling and production equipment — Marine drilling riser ciouplings.

53. GS ISO 13626:2003 Petroleum and natural gas industries — Drilling and production equipment — Drilling and well-serving structures.

54. GS ISO 13628-1:2005 Petroleum and natural gas industries — Design and operation of subsea production systems — Part 1: General requirements and recommendations.

55. GS ISO 13628-2:2006 Petroleum and natural gas industries — Design and operation of subsea production systems — Part 2: Unbounded flexible pipe systems for subsea and marine applications.

56. GS ISO 13628-2:2006/Cor. 1:2009 Petroleum and natural gas industries— Design and operation of subsea production systemst— Part 2: Unbonded flexible pipe systems for subsea and marine applications. TECHNICAL CORIGENDUM 1.

57. GS ISO 13628-3:2000 Petroleum and natural gas industries—Design and operation of subsea production systems— Part 3: Through flow line (TFL) systems.

58. GS ISO 13628-5:2009 Petroleum and natural gas industries — Design and operation of subsea production systemst — Part 5: Subsea umbilicals.

59. GS ISO 13628-6:2006 Petroleum and natural gas industries — Design and operation of subsea production systems — Part 6: Subsea production control systems.

60. GS ISO 13628-7:2005 Petroleum and natural gas industries — Design and operation of subsea production system — Part 7: Completion/workpver riser systems.

61. GS ISO 13628-8:2002 Petroleum and natural gas industries — Design and operation of subsea production systems — Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems.

62. GS ISO 13628-8:2002/Cor. 1:2005 Petroleum and natural gas industries — Design and operation of subsea production systems — Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems. TECHNICAL CORRIGENDUM 1.

63. GS ISO 13628-10:2005 Petroleum and natural gas industries — Design and operation of subsea production systems — Part 10: Specicification[sic] for bounded flexible pipe.

64. GS ISO 13628-11:2007 Petroleum and natural gas industries — Design and operation of subsea production systems — Part 11: Flexible pipe systems for subsea and marine applications.

65. GS ISO 13628-11:2007/Cor. 1:2008 Petroleum and natural gas industries — Design and operation of subsea production systems — Flexible pipe systems for subsea and marine applications. TECHNICAL CORRIGENDUM 1.

66. GS ISO 13628:2009 Petroleum and natural gas industries — Design and operation of subsea production systems — Evaluation and testing of thread compounds for use with casing, tubing, line pipe and drill stem elements.

67. GS ISO 13628:2000/Cor. 1:2005 Petroleum and natural gas industries — Evaluation and testing of thread compounds for use with casing, tubing, line pipe and drill stem elements. TECHNICAL CORRIGENDUM 1.

68. GS ISO 13680:2008 Petroleum and natural gas industries— Corrosion-resistant alloy seamless tubes for use as casing, tubing and coupling stock—Technical delivery conditions.

69. GS ISO 13703-8:2000 Petroleum and natural gas industries — Design and installation of piping sustems on offshore production platforms.

70. GS ISO 13703:2000/Cor. 1:2002 Petroleum and natural gas industries — Design and installation of piping systems on offshore production platforms. TECHNICAL CORRIGENDUM 1.

71. GS ISO 13704:2007 Petroleum and natural gas industries—Calculation of heater tube thickness in petroleum refineries.

72. GS ISO 13704:2007/Cor. 1:2008 Petroleum, petrochemical and natural gas industries—Calculation of heater-tube thickness in petroleum refineries. TECHNICAL CORRIGENDUM 1.

73. GS ISO 13706:2005 Petroleum, petrochemical and natural gas industries—Air-cooled heat exchangers.

74. Par 4.23 GS ISO 13847:2000 Petroleum, petrochemical and natural gas industries—Pipeline transportation systems—Welding of pipelines.

75. Par 4.23 GS ISO 13847:2000/Cor 1:2001 Petroleum, petrochemical and natural gas industries—Pipeline transportation systems—Welding of pipelines.

76. GS ISO 14224:2006 Petroleum and natural gas industries—Collection and exchange of reliability and maintenance data for equipment.

77. GS ISO 14310:2008 Petroleum and natural gas industries—Downhole equipment—Packers and bridge plugs.

78. Par. 1.13 (a) 3.5 & 3.6GS ISO 14313:2007 Petroleum and natural gas industries—Pipeline transportation systems – Pipeline valves.

79. GS ISO 14313:2007/Cor. 1:2009 Petroleum and natural gas industries—Pipeline transportation systems-Pipeline valves. TECHNICAL CORRIGENDUM 1.

80. GS ISO 14691:2008 Petroleum and natural gas industries—Flexible couplings for mechanical power transmission—General-purpose applications.

81. GS ISO 146921:2002 Petroleum and natural gas industries—Glass-reinforced plastics (GRP) piping—Part 1: Vocabulary, symbols, applications and materials.

82. GS ISO 14692-2:2002 Petroleum and natural gas industries—Glass reinforced plastics (GRP) piping Part 2: Qualification and manufacture.

83. GS ISO 14692-2:2002/Cor. 1:2005 Petroleum and natural gas industries—Glass reinforced plastics (GRP) piping Part 2: Qualification and manufacture. TECHNICAL CORRIGENDUM 1.

84. GS ISO 14692-3:2003 Petroleum and natural gas industries—Glass-reinforced plastics (GRP) piping – Part 3: System design.

85. GS ISO 14692-2:2002/Cor. 1:2005 Petroleum and natural gas industries—Glass reinforced plastics (GRP) piping – Part 3: TECHNICAL CORRIGENDUM 1.

86. GS ISO 14692-4:2002 Petroleum and natural gas industries—Glass reinforced plastics (GRP) piping – Part 4: Fabrication, installation and operation.

87. GS ISO 14693:2003 Petroleum and natural gas industries—Drilling and well-serving equipment

88. Par. 3.47 (c) GS ISO 14723:2009 Petroleum and natural gas industries—Pipeline transportation systems-Subsea pipeline valves.

89. GS ISO 15136-1:2009 Petroleum and natural gas industries—Progressing cavity pump systems for artificial lift – Part 1: Pumps.

90. GS ISO 14692-2:2002 Petroleum and natural gas industries—Progressing cavity pump systems for artificial lift – Part 1: Pumps.

91. GS ISO 15138:2007 Petroleum and natural gas industries—Offshore production installations-heating, ventilation and air-conditioning.

92. GS ISO 15156-1:2009 Petroleum and natural gas industries—Materials for use in H2S-containing environments in oil and gas production – Part 1: General principles for selection of cracking-resistant materials.

93. GS ISO 15156-2:2009 Petroleum and natural gas industries—Materials for use in H2S-containing environments in oil and gas production – Part 2: Cracking-resistant carbon and low-alloy steels, and the use of cast irons.

94. GS ISO 15156-3:2009 Petroleum and natural gas industries —Materials for use in H2S-conataining environments in oil and gas production – Part 3: Cracking—resistant CRAs (corrosion-resistant alloys) and other alloys.

95. GS ISO 15463:2003 Petroleum and natural gas industries-Field inspection of new casing tubing and plain-end drill pipe.

96. GS ISO 15463:2003/Cor. 1:2009 Petroleum and natural gas industries—Field inspection of new casing, tubing and plain-end drill pipe. TECHNICAL CORRIGENDUM 1.

97. GS ISO 1544:2000 Petroleum and natural gas industries —Offshore production installations-Requirements and guidelines for emergency response.

98. GS ISO 1544:2000/Amd. 1:2009 Petroleum and natural gas industries—Offshore production installations –Requirements and guidelines for emergency response. AMENDMENT 1.

99. GS ISO 15546:2007 Petroleum and natural gas industries—Aluminum alloy drill pipe.

100. GS ISO 15547-1:2005 Petroleum, petrochemical and natural gas industries—Plate-type heat exchangers –Part 1: Plate-and-frame heat exchangers.

101 GS ISO 15547-2:2005 Petroleum, petrochemical natural gas industries—Plate-type heat exchangers – Part 2 : Brazed aluminum plate-fin heat exchangers.

102. GS ISO 15589-1:2003 Petroleum and natural gas industries—Cathodic protection systems – Part 1: On-land pipelines.

103. GS ISO 15589-2:2004 Petroleum and natural gas industries—Cathodic protection systems – Part 2: Offshore pipelines.

104. Par. 1.13 (a) GS ISO 15590-1:2009 Petroleum and natural gas industries—Cathodic protection systems-Part 1: Induction bends, fittings and flanges for pipeline transportation systems—Part 1: Induction bends

105 Par. 1.13 (a) 3.12, 3.14 (a) GS ISO 15590-2:2003 Petroleum and natural gas industries—Induction bends, fittings and flanges for pipeline transportation systems – Part 2: Fittings.

106. GS ISO 15590-3:2004 Petroleum and natural gas industries—Induction bends, fittings and flanges for pipeline transportation systems – Part 3: Flanges.

107. GS ISO 15663-1:2000 Petroleum and natural gas industries—Life cycle costing- Part 1: Methodology

108. GS ISO 15663-1:2000 Petroleum and natural gas industries—

109. GS ISO 16708:2006 Petroleum and natural gas industries—Pipeline transportation systems – Reliability-based limit state methods.

110. GS ISO 16812:2007 Petroleum, petrochemical and natural gas industries—Shell and tube heat exchangers.

111. GS ISO 17078-1:2004 Petroleum and natural gas industries—Drilling and production equipment –Part 1: Side-pocket mandrels.

112. GS ISO 17078-2:2007 Petroleum and natural gas industries—Drilling and production equipment – Part 2: flow-control devices for side-pocket mandrels.

113. GS ISO 17078-2:2007/Cor. 1:2009 Petroleum and natural gas industries—Drilling and production equipment-Part 2: Flow-control devices for side-pocket mandrels. TECHNICAL CORRIGENDUM 1.

114. GS ISO 17078-3:2009 Petroleum and natural gas industries—Drilling and production equipment- Part 3: Running tools, pulling tools and kick-over tools and latches for side-pocket mandrels.

115. GS ISO 17776:2000 Petroleum and natural gas industries —Offshore production installations – Guidelines on tools and techniques for hazard identification and risk assessment.

116. GS ISO 17824:2009 Petroleum and natural gas industries— Downhole equipment-Sand screens

117. GS ISO 19900:2002 Petroleum and natural gas industries—General requirements for offshore structures

118. GS ISO 19901-1:2005 Petroleum and natural gas industries—Specific requirements for offshore structures – Part 1: metocean design and operating considerations

119. GS ISO 19901-2:2004 Petroleum and natural gas industries—Specific requirements for offshore structures – Part 2: Seismic design procedures and criteria.

120. GS ISO 19901-4:2003 Petroleum and natural gas industries—Specific requirements for offshore structures – Part 4: Geotechnical and foundation design considerations

121. GS ISO 19901-5:2003 Petroleum and natural gas industries—Specific requirements for offshore structures – Part 5: Weight control during engineering and construction.

122. GS ISO 19901-6:2009 Petroleum and natural gas industries—Specific requirements for offshore structures – Part 6: Marine operations.

123. GS ISO 19901-472005 Petroleum and natural gas industries—Specific requirements for offshore structures – Part 7 : Station keeping systems for floating offshore structures and mobile offshore units.

124. GS ISO 19901:2007 Petroleum and natural gas industries—Fixed steel offshore structures

125. GS ISO 19903:2006 Petroleum and natural gas industries—Fixed concrete offshore structures

126. GS ISO 19903:2006 Petroleum and natural gas industries

127. GS ISO 20815:2008 Petroleum and natural gas industries—Production assurance and reliability management

128. GS ISO 21329:2004 Petroleum and natural gas industries—Pipeline transportation systems – Test procedures for mechanical connectors

129. GS ISO 21809:2007 Petroleum and natural gas industries—External coatings for buried for submerged pipelines used in pipeline transportation systems- Part 2: Fusion-bonded epoxy coatings

130. GS ISO 21809:2007/Cor. 1:2008 Petroleum and natural gas industries—External coatings for buried or submerged pipelines used in pipeline transportation systems – Part 2: Fusion-bonded epoxy coatings TECHNICAL CORRIGENDUM 1.

131. GS ISO 21809-3:2008 Petroleum and natural gas industries—External coatings for buried or submerged pipelines used in pipeline transportation systems – Part 3: Field joint coatings.

132. GS ISO 21809-4:2009 Petroleum and natural gas industries—External coatings for buried or submerged pipelines used in pipeline transportation systems – Part 4: Polythylene coatings (2-layer PE).

133. GS ISO 23251:2006/Amd. 1:2008 Petroleum, petrochemical and natural gas industries—Pressure-relieving and depressuring systems.

134. GS ISO 23251:2006/Cor. 1:2007 Petroleum, petrochemical and natural gas industries—Pressure-relieving and depressuring systems. AMENDMENT 1

135. GS ISO 23936-1:2009 Petroleum, petrochemical and natural gas industries—Pressure-relieving and depressuring systems. TECHNICAL CORRIGENDUM 1

136. GS ISO /TS 24817:2006 Petroleum, petrochemical and natural gas industries—Non-metallic materials in contact with media related to oil and gas production-Part 1: Themoplastics

137. GS ISO 25457:2008 Petroleum, petrochemical and natural gas industries—Pressure-relieving and depressuring systems

138. GS ISO 28300:2008 Petroleum, petrochemical and natural gas industries—Flare details for general refinery and petrochemical service

139. GS ISO 28300:2008/Cor. 1:2009 Petroleum, petrochemical and natural gas industries—Venting of atmospheric and low-pressure storage tanks.

140. GS ISO/TS 28300:2008/Cor. 1:2009 Petroleum, petrochemical and natural gas indusrites—Venting of atmospheric and low-pressure storage tanks.

141. GS ISO/TS 29001:2007 Petroleum, petrochemical and natural gas industries—Sector-specific quality management systems – Requirements for product and service supply organizations.

142. Par. 14. 12., 14.14, 14.20(i), 14.20(k), 14.20 (m), 14.22 (a), 14.23, 14.33, 14.35, 14.46, 14.53 (a), 14.173 ASME/ANSI B31.8s Supplement ASME B31.8 on Managing System Integrity of Gas Pipelines

143. Par. 2.17 PPT TR-3/2000 Policies and procedures for developing Hydrostatic Design Bases (HDB), Pressure Design Bases (PDB) and Minimum Required Strength (MRS).

144. Par. 3.80, 5.13(a), 5.17(i), 5.17(ii), 5.17(iii) ASTM Specification

ASTM D 2517:1979 Standard specification for reinforced epoxy resin gas pressure pipe and fittings.

145. Par. 5.11 (b), 5.17 (c) ASTM d 2513:1999 Standards Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings

146. Par. 5.8 ASME/ANSI B16.5:1977 Cast pipe flanges and flanged fittings

147. Par. 5.19 (a) ASTM D 638-1999 Standard Test Method for Tensile Properties of Plastic

148. Par. 8.64 ASME/ANSI B31G Manual for determining the remaining of corroded pipe-lines

149. Par. 9.10 (c) ASME/ANSI, MSS specifications —

150. Par. 11.26 to 11.28 API (RP) 1162 1st Edition (December Public Awareness Programs for Pipeline Operators.

PART B

STEEL PIPE OF UNKNOWN OR UNLISTED SPECIFICATION

(a) Bending Properties – For pipe 51 millimetres or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For a pipe of more than 51 millimetres in diameter the pipe must meet the requirements of the flattening test specified in this Schedule, except that the number of tests must at the least be equivalent to the minimum requirements of paragraph (d) to determine yield strength.

(b) Weldability – A girth weld must be made in the pipe by a welder who is qualified under paragraphs 4.4 and 4.6 of the Fourth Schedule. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the filed. On pipe more than 102 millimetres in diameter, at least one test weld must be made for each 100 lenghts of pipe. On pipe 102 millimetres or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with the standard specified in the Fifteenth Schedule. If the requirements of the standard specified in the Fifteenth Schedule cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with the required standard specified in the Fifteenth Schedule. The same number of chemical tests must be made as are required for testing a girth weld.

(c) Inspection – The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there is no defect which might impair the strength or tightness of the pipe.

(d) Tensile Properties – If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 166 megapascals or less, or the tensile properties may be established by performing tensile tests in accordance with the requirements specified in this Schedule. Every test specimen shall be selected at random and the following number of tests must be performed.

Number of tensile tests — All sizes

10 lengths or less:	1 set of tests for each length
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in paragraph 1.7 of the First Schedule.

PART C

TRANSPORTATION OF NATURAL GAS BY PIPELINE: MINIMUM SAFETY STANDARDS

Table E.II.1: Preventive and Mitigative Measures for Transmission Pipe lines Operating below 30% SMYS not in an HCA but in a Class 3 and 4 Location

Threat Existing Requirements Additional requirements Preventive and Mitigative Measures

Primary Secondary

External Corrosion Par. 8.3 to 8.8 – (General)

Par. 8.9 and 8.10 – (Examination)

Par. 8.11 to 8.15 – (External Coating)

Par. 8.17 and 8.17[sic] – (Cathodic Protection) Par. 8.26 to 8.33 – (Monitoring), Par. 8.34 to 8.39 – (Electrical isolation),

Par. 8.40 – (Test station)

Par. 8.41 to 8.43 – (Test leads),

Par. 8.44 and 8.45 – (Interference),

Par 8.52 to 8.54 – (Atomspheric),

Par. 8.55 to 8.57- (Atomspheric),

Par. 8.61 and 8.62 – (Remedial),

Par. 12.4 to 12.6 – (Patrol),

Par. 12.7 and 12.8 – (Leak survey),

Par. 12.9 and 12.10 – (Repair B gen.)

Par. 12.14 – (Repair B perm) Par. 11.2 – (General Operation) Par. 11.14 and 11.15- (Surveillance) For Cathodically Protected Transmission Pipeline:

Perform semi-annual leak survey.

For unprotected Transmission Pipelines or for Cathodically Protected Pipe where Electrical Surveys are impractical:

Perform quarterly leak surveys

Internal Corrosion Par. 8.46 to 8.49 – (General Internal Corrossion),

Par 8.50 and 8.51 – (Internal Corrosion monitoring),

Par. 8.61 and 8.62 – (Remedial),

Par. 12.4 to 12.6 – (Patrol),

Par. 12.7 and 12.8 – (Leak survey),

Par. 12.9 and 12.10 – (Repair B gen.)

Par. 12.14-(Repair B perm) Par. 11.2-(General Operation) Par. 11.14 and 11.15 - Surveillance)
Perform semi-annual leak surveys.

3rd Party Damage Par. 2.2-(Gen. Design),

Par. 2.11 to 2.14- (Design factor),

Par. 6.14 to 6.16- (Hazard protection.),

Par. 6.36 to 6.40- (Cover),

Par. 11.16 to 11.21 - (Damage Prevention), Par. 11.26 to 11.33 -(Public education),

Par. 12.4 to 12.6- (Patrol),

Par. 12.9 and 12.10 - (Repair B gen.)

Par. 12.14 -(Repair B perm) Par. 11.22 - (Emergency Plan.) Participation in state one-call system,

Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND

Either monitoring of excavations near operator-s transmission pipelines, or bi-monthly patrol of transmission pipelines in class 3 and 4 locations. Any indications of unreported construction activity would require a follow-up investigation to determine if mechanical damage occurred.

TRANSPORTATION OF NATURAL GAS BY PIPELINE: MINIMUM SAFETY STANDARDS

Table E.II.2 Assessment Requirements for Transmission Pipeline in HCAs (Re-assessment intervals are maximum allowed)

Re-assessment Requirements (See Note 3)

At or above 50% SMYS At or above 30% SMYS up to 50% SMYS Below 30% SMYS

Baseline Assessment Method (see Note 3) Max Re-assessment

Internal Assessment Method Max Re-assessment

internal Assessment Method Max Re-assessment

internal Assessment Method

Pressure Testing 7 CDA 7 CDA

Ongoing Preventive and Mitigative (P and M) Measures (see Table E11.3), (see Note 2)

10 Pressure Test or ILI or DA

Repeat Inspection cycle every 10 years 15 (see Note 1) Pressure Test or ILI or DA (see Note 1)

Repeat Inspection cycle every 15 years 20 Pressure Test or ILI or DA

Repeat Inspection cycle every 20 years

In-Line Inspection 7

10 CDA

ILI or Pressure or Test

15 (see Note 1)

ILI or Pressure or Test (see Note 1)

Ongoing Preventive and Mitigative (P and M) Measures (see Table E11.3), (see Note 2)

Repeat Inspection cycle every 10 years 20 ILI or Pressure Test

Direct Assessment 7 CDA 7 CDA Repeat Inspection cycle every 20 years

10 DA or ILI or Pressure Test 15 (see Note 1) Da or ILI or Pressure Test or ILI or DA (see Note 1)

Ongoing Preventive & Mitigative (P and M) Measures (see Table E11.3), (SEE Note 2)

DA or ILI or Pressure Test

Repeat Inspection cycle every 10 years

Repeat Inspection cycle every 10 years

Repeat Inspection cycle every 15 years 20

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, pressure Test, or DA at year 15 as allowed under ASME B31.8S.

Note 2: Operator may chose to utilize DCA at year 7 and 14 in lieu of P & M.

Note 3: Operator may utilize "Other technology that an operator demonstrates can provide an equivalent understanding of the condition of pipe line".

Confirm Direct Assessment—CDA

Direct Assessment—DA

High Consequence Area—HCA

In-line Inspection—ILI.

TRANSPORTATION OF NATURAL GAS BY PIPELINE: MINIMUM SAFETY STANDARDS

Table E.II.3: Preventive & Metigative Measures for Transmission Pipe lines Operating below 30% SMYS not in an HCA but in a Class 3 and 4 Location

Threat Existing Requirements Additional requirements

Primary Secondary Preventive and Mitigative Measures

External Corrosion Par. 8.3 to 8.8 - (General)

Par. 8.9 and 8.10 - (Examination) Par. 11.2 -(General Operation) For Cathodically Protected Transmission Pipeline:

Par. 8.11 to 8.15 - (External Coating)

Par. 8.17 and 8.17[sic] - (Catholic Protection)

Par. 8.26 to 8.33 - (Monitoring).

Par. 8.34 to 8.39 - (Electrical isolation).

Par. 8.40 -(Test station)

Par. 8.41 to 8.43 (Test leads).

Par. 8.44 & 8.45 - (Interference). Par. 11.14 & 11.15 - (Surveillance) Perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years.

Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment.

Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impracticable:

Par. 8.52 to 8.54 (Atmospheric)

Par. 8.55 to 8.57 (Atmospheric)

Par. 8.61 and 8.62 (Remedial)

Par. 12.4 to 12.6 (Patrol)

Par. 12.7 and 12.8 - (Leak survey)

Par. 12.9 and 12.10 (Repair B gen.)

Par. 12.14 - (Repair B perm). Conduct quarterly leak surveys AND

Every 1 ½ years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records and the pipeline environment.

Internal Corrosion Par. 8.46 to 8.49 - (General Internal Corrosion).

Par. 850 and 8.51 - (Internal Corrosion monitoring)

Par. 8.61 and 8.62 (Remedial),

Par. 12.4 to 12.6 (Patrol),

Par. 12.7 and 12.8 (Leak survey) Par. 11.2 - (Gen Operation)

Par. 11.14 and 11.15 - (Surveillance) Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCAs.

Periodic testing of fluid removed from pipelines. Specifically, once each calendar year from each storage field that may affect transmission pipeline in HCAs, AND

At least every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repairs records, patrol records, exposed pipe reports, and test records participation in state one-call system.

3rd Party Damage Par. 2.2 - (Gen. Design)

Par. 2.11 to 2.14 - (Design factor).

Par. 6.14 to 6.16 (Hazard protection).

Par. 6.36 to 6.40 (Cover),

Par. 11.16 to 11.21 - (Damage Prevention),

Par. 11.26 to 11.33 (Public education),

Par. 12.4 to 12.6 - (Patrol),

Par. 12.9 and 12.10 - (Repair B gen.)

Par 12.14 - (Repaid B perm) 615 B (Emerg. Plan.) Use of qualified operator employees and contractors to perform marking and location of buried structures and in direct supervisor of excavation work, AND

Either monitoring of excavations near operator-s transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or class 3 and 4 locations. Any indications of unreported construction activity would require a follow-up investigation to determine if mechanical damage occurred.

PART D

INTERPRETATION

“ASME” means American Society of Mechanical Engineers

“ASTM” means American Society for Testing and Materials

“ANSI” means American National Standard Institute

“API" means American Petroleum Institute

“MSS” means Manufacturers Standardization Society

”PPI” means Plastic Pipe Institute

“TR” means Technical Report.

SIXTEENTH SCHEDULE

(Regulation 3)

LIST OF ORGANISATIONS

1. American Gas Association (AGA)

2. American National Standard Institute (ANSI)

3. American Petroleum Institute (API),

4. American Society for Testing and Materials (ASTM),

5. American Society of Mechanical Engineers (ASME),

6. Gas Technology Institute (GTI),

7. Manufacturers Standardization Society of Valve and Fittings Industry (MSS),

8. National Fire Protection Association (NFPA),

9. National Association of Corrosion Engineers (NACE),

10. Plastics Pipe Institute (PPI),

11. Standards Authority.

SEVENTEENTH SCHEDULE

(Regulations 10 and 13)

QUALIFICATION TESTS FOR WELDERS FOR LOW STRESS LEVEL PIPE

1. Basic test. The test is made on pipe 305 millimetres or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. After completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 3.0 millimeters long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during a test shall not be considered.

2. Additional tests for welders of service line connections to mains. A service line connection fitting is welded to a pipe section with the same diameter as the typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

3 Periodic tests for welders of small service lines. Two samples of the welder’s work, each about 203 millimeters long with the weld located approximately in the center, are cut from a steel service line and tested as follows:

(a) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 51 millimetres on each side of weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(b) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is acceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (a).

HON. DR. JOE OTENG-ADJEI

Minister responsible for Energy

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