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BURIED AND UNDERGROUND PIPING AND TANK AGEING MANAGEMENT FOR NUCLEAR POWER PLANTS

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FOREWORD

One of the IAEA's statutory objectives is to "seek to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world." One way this objective is achieved is through the publication of a range of technical series. Two of these are the IAEA Nuclear Energy Series and the IAEA Safety Standards Series.

According to Article III.A.6 of the IAEA Statute, the safety standards establish "standards of safety for protection of health and minimization of danger to life and property". The safety standards include the Safety Fundamentals, Safety Requirements and Safety Guides. These standards are written primarily in a regulatory style, and are binding on the IAEA for its own programmes. The principal users are the regulatory bodies in Member States and other national authorities.

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There are currently over 400 operational nuclear power plants in IAEA Member States, and around 60 under construction. Operating experience has shown that ineffective control of ageing degradation of major nuclear power plant components (e.g. caused by unanticipated phenomena and by operating, maintenance, design or manufacturing errors) can jeopardize plant safety and reduce plant life. Ageing in nuclear power plants must be effectively managed to ensure availability of design functions throughout plant service life. From the safety perspective, this means controlling, within acceptable limits, ageing degradation and wear-out of plant components so that adequate safety margins remain.

This publication is one in a series of reports on the assessment and management of ageing of major nuclear power plant components. Current practices for the assessment of safety margins (fitness for service) and the inspection, monitoring and mitigation of ageing degradation of underground piping related to Canada deuterium–uranium (CANDU) reactor plants, boiling water reactor plants, pressurized water reactor plants and water moderated, water cooled power reactor plants are documented. This information is intended to help all those involved directly or indirectly in ensuring the safe operation of nuclear power plants and to provide a common technical basis for dialogue between plant operators and regulators when dealing with age related licensing issues.

This report is intended for technical experts from nuclear power plants and from regulatory, plant design, manufacturing and technical support organizations dealing with buried and underground piping or tanks.

The IAEA officer responsible for this publication was J.H. Moore of the Division of Nuclear Power.

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1. INTRODUCTION

1.1. OBJECTIVE

This publication provides information regarding good practices for the assessment and management of ageing related to buried and underground piping and tanks within a nuclear power plant. Specifically, the objectives of this report are to provide:

- State of the art information regarding ageing management of underground piping in nuclear power plants throughout their entire service life, including the after service period;
- Background material indicating the importance of ageing management programmes (AMPs);
- Practices and techniques for assessing fitness for service and for inspection, monitoring and mitigation
 of ageing related degradation of underground piping important for the safe, reliable and environmentally
 acceptable operation of nuclear power plants;
- A technical basis for developing and implementing a systematic ageing management programme;
- Guidelines that can be used to ensure that ageing management is taken into account during different phases of a nuclear power plant's life cycle (i.e. design, fabrication and construction, commissioning, operation (including long term operation and extended shutdown) and decommissioning);
- Research materials related to ageing and lessons learned.

This report is intended for plant owners, operators, designers, engineers and specialists to:

- Establish, implement and improve AMPs for nuclear power plants;
- Facilitate dialogue between owners/operators and regulators when dealing with age related licensing issues;
- Consider ageing in the design of new plants and modifications and in approaches to mitigating ageing effects.

1.2. BACKGROUND

1.2.1. Safety aspects of buried and underground piping systems and tanks

Buried and underground piping systems associated with nuclear power plants have a number of safety aspects. Their integrity is maintained at plants to ensure nuclear safety, equipment reliability and environmental protection.

Numerous nuclear power plants have experienced leakages of radioactive materials from underground structures (piping, tanks, etc.) that caused contamination of groundwater. For example, some 45 of 65 US plants have had leaks or spills involving tritium in excess of 740 Bq/L at some time during their operating history [1]. Although there were no identified risks to public health and safety, the findings raised questions regarding plant vulnerability to underground piping corrosion and its potential impact on the public and environment. As a result, several initiatives (e.g. the 2006 Groundwater Protection Initiative in the United States of America) were put in place, a number of task groups (e.g. the National Association of Corrosion Engineers (NACE) Task Group (TG 404) and the Electrical Power Research Institute's (EPRI) Buried Pipe Integrity Group (BPIG)) were formed and several guidelines (e.g. the Nuclear Energy Institute's NEI 09-14 [2]) were produced. To restore public confidence, utilities proactively started adopting these guidelines and associated milestones.

Codes and standards within IAEA Member States are not consistent in their treatment of buried piping. Some jurisdictions have little or no specific guidance, while others have guidance in the form of regulations on the environment, the handling of chemicals or petrochemicals, or pressure boundaries.

1.2.2. Need for ageing management of buried and underground piping and tanks

The design life of most nuclear power plants was typically chosen to be 30–40 years. There are, however, economic benefits for utilities to extend plant service life (with 60 years or more being a quoted target), delayed construction schedules and/or decommissioning strategies that involve use of some plant structures as a 'safe store'

for periods of up to 100 years. This can mean that buried and underground piping systems at plants often have to perform functions for a time period significantly greater than their initial design life.

A number of existing nuclear power plant programmes, such as periodic inspection and testing, surveillance, and preventive and corrective maintenance, contribute to proper ageing management of underground piping. The effectiveness and efficiency of ageing management can be improved by integrating and modifying these programmes, as appropriate, within a systematic AMP.

The IAEA Safety Standards Series No. NS-G-2.12 [3] provides a systematic and integrated approach to managing ageing (see Fig. 2 of this publication). Development of a systematic AMP and the interaction of key elements of such a programme are discussed later in this report.

Ageing management of buried and underground piping and tanks is more difficult than that for above ground systems. Access for routine surveillance and maintenance is more difficult and expensive, resulting in fewer opportunities to detect, mitigate and address degradation. A well planned AMP will optimize inspections to minimize costs while maintaining appropriate oversight of the systems in question.

Environmental cleanup, transportation and disposal of contaminated soil and other costs connected to a reportable leak can result in a substantial expenditure in terms of time and money. Effective AMPs can help reduce or eliminate premature plant failures that cause spills or radioactive leaks and thus reduce potential damage liabilities. In addition, some structures may be required to be maintained per government regulations. Cathodic protection of related metallic structures is essential to maintain any metallic structure in a corrosive environment at the lowest life cycle cost.

1.2.3. IAEA programme on safety aspects of nuclear power plant ageing

To help Member States understand the ageing of systems, structures and components (SSCs) important to safety and the effective ageing management of these SSCs, the IAEA in 1989 initiated a project on the safety aspects of nuclear power plant ageing. This project integrated information on the evaluation and management of safety aspects of plant ageing that had been generated by Member States into a common knowledge base. The IAEA issued numerous publications that assisted Member States with their ageing management programmes. The programme has continued to be developed over the years. A summary of activities undertaken is included in Appendix I.

1.3. SCOPE AND STRUCTURE OF THIS REPORT

This report deals with underground piping systems that are part of a nuclear power plant. It addresses potential ageing mechanisms, age-related degradation and ageing management (i.e. inspection, monitoring, assessment and remedial measures) as well as condition assessments for the materials and components of underground piping systems, such as:

- Piping;
- Tanks;
- Tunnels;
- Vaults;
- Supports and anchors;
- Penetrations;
- Air release valves;
- Electrical conduit¹.

This report follows the structure of the generic AMPs defined in Ref. [3].

¹ An electrical conduit is not typically formally part of industry developed buried piping programmes; however, it is similar in construction to, subject to many of the same degradation mechanisms (on the outside diameter), and can be inspected and repaired with some of the same methods as buried piping, and so is included in this publication.

That is, Section 2 introduces the generic AMP as it relates to underground piping and tanks, Section 3 describes underground piping and tank material and Sections 4 through 8 discuss each of the process steps of an effective AMP:

- Understanding ageing;
- Developing and optimizing the AMP;
- Plant operation;
- Inspection, monitoring and assessment;
- Maintenance and repair.

Within each section are both process steps and information that is specific to underground piping and tanks and that supplements the generic information provided in Ref. [3].

Finally, Section 9 summarizes the conclusions of this publication and provides recommendations for plant personnel.

Appendices cover IAEA ageing management activities, some specific material properties, ageing management practices within selected Member States and non-nuclear industries, and some sample programme health reports dealing with buried and underground piping.

1.4. TERMINOLOGY

Common terminology for ageing management in a nuclear power plant context is typically derived from industry sources (see, e.g., Ref. [4]). In an IAEA context ageing management is defined in the IAEA Safety Glossary [5] and annex I of Ref. [3] points to other typical publications. Figure 1 shows the relationships among terms describing actual life events on an event timeline (based on figure 4 of Ref. [4]).



FIG. 1. Lifetime periods of structures, systems and components.

Reference [5] defines ageing management as:

 Engineering, operations and maintenance actions to control within acceptable limits the ageing degradation of structures, systems and components.

Examples of engineering actions include *design*, *qualification* and *failure analysis*. Examples of *operations* actions include surveillance, carrying out operating *procedures* within specified *limits* and performing environmental measurements.

Life management (or lifetime management) is the integration of ageing management with economic planning: (1) to optimize the operation, maintenance and service life of SSCs; (2) to maintain an acceptable level of performance and safety; and (3) to maximize the return on investment over the service life of the facility.

This publication focuses on the service life period of SSCs.

2. AGEING MANAGEMENT BASICS

This section describes the five components of an AMP for underground piping and tanks. Subsequent sections address each component in more detail in order to facilitate the preparation of plant specific AMPs by users of this publication.

The IAEA publication Safety Standards Series No. SSR-2/2, Safety of Nuclear Power Plants: Commissioning and Operation [6], establishes a requirement that nuclear power plant operating organizations ensure that an effective AMP is implemented so that "required safety functions of systems, structures and components are fulfilled over the entire operating lifetime of the plant". Reference [3] provides recommendations for effective ageing management of such plant SSCs.

The primary objective of an AMP for underground piping is to ensure the timely detection and mitigation of any degradation that could impact on safety functions. Where applied to non-safety-related systems, AMPs can have economic benefits by detecting piping degradation that could lead to dangerous situations, environmental releases or plant unavailability.

The main characteristic of an AMP is a systematic, comprehensive and integrated approach aimed at ensuring the most effective and efficient management of ageing. A comprehensive understanding of piping systems, their ageing degradation mechanisms and the effects of degradation on a system's ability to perform its design functions is a fundamental element of an AMP. This understanding is derived from knowledge of:

- Plant design basis;
- Applicable codes and regulatory requirements;
- Plant design;
- Plant fabrication methods;
- Material properties;
- Service conditions;
- Operation and maintenance history;
- Commissioning;
- Surveillance methods;
- Inspection results;
- Generic operating experience;
- Research results.

Figure 2 shows a systematic approach for managing the ageing of a structure or component. A systematic AMP consists of a feedback loop with the following activities:

- (1) Understanding of structure/component ageing;
- (2) Development and optimization of activities for ageing management;



FIG. 2. Systematic approach to managing ageing of a structure or component (adapted from Ref. [3]).

- (3) Operation of a plant within design limits to minimize age related degradation (in particular, error-induced accelerated degradation);
- (4) Inspection, monitoring and assessment to detect and characterize significant component degradation before fitness for service is compromised;
- (5) Maintenance to manage ageing effects.

Such an AMP should be implemented by a multidisciplinary ageing management team organized at a corporate or owners' group level.

The generic attributes of an AMP should include the following (see Ref. [3] for details):

- Scope of the AMP based on understanding ageing;
- Preventive actions to minimize and control ageing degradation;
- Detection of ageing effects;
- Monitoring and trending of ageing effects;
- Mitigating ageing effects;
- Acceptance criteria;
- Corrective actions;

- Operating experience feedback and feedback of research and development results;

— Quality management.

See IAEA Safety Reports Series No. 15 [7] and Section 5.7 of this publication for information on the organizational aspects of a plant AMP and interdisciplinary ageing management teams. Contained in Ref. [7] are suggested indicators of AMP effectiveness, stated as results oriented criteria.

Groups such as NACE have developed similarly structured programmes for buried piping management using slightly different terminology [8]. Table 1 describes NACE's four step process of internal corrosion and external corrosion direct assessment (ICDA and ECDA) and roughly how it corresponds to the IAEA's systematic AMP framework.

NACE defines its process steps as follows [8]:

- (1) **Preassessment** includes the collection of design and operating data, as well as environmental information and any corrosion protection measures, to determine the feasibility of applying the direct assessment procedure to the pipeline in question. Preassessment also separates the line into discrete segments ('ECDA regions') based upon various design and operating characteristics.
- (2) **Indirect inspection** considers further details of design and operation to determine the locations most susceptible to corrosion. In ECDA the indirect inspection step requires using at least two at-grade or above ground inspections over the entire length of each ECDA region. It is not a direct physical examination of piping, but rather a detailed review of design, operation, treatment, repair and indirect inspection reports.
- (3) **Direct examination** includes actual volumetric measurements as well as predictions of corrosivity, corrosion monitoring results, other inspection results (e.g. visual) and elimination of consideration of some segments of piping depending upon the results from locations considered to be more susceptible to corrosion. It requires excavations to expose the pipe surface so that measurements can be made of the pipe and in the immediate surrounding environment. A minimum of one dig is required regardless of the results of indirect inspections and preassessment steps.
- (4) **Postassessment** analyses data from the first three steps to assess the overall effectiveness of the direct assessment process and determines reassessment intervals.

NACE process	Corresponding IAEA framework	Relevant section(s) of this publication	
Preassessment	Understanding ageing of structure/component	Section 4	
	Development and optimization of activities for ageing management	Section 5.3	
Indirect inspection	Understanding ageing of structure/component	Sections 5.4, 5.5 and 7.3.2	
Direct inspection	Inspection, monitoring and assessment of ageing	Section 7	
(not specifically covered)	Operation/use of a component	Section 6	
(not specifically covered)	Maintenance of a structure/component	Section 8	
Postassessment	Development and optimization of activities for ageing management	Sections 5.7.2, 5.8	

TABLE 1. COMPARISON OF NACE AND IAEA AGEING MANAGEMENT FRAMEWORKS

3. BURIED AND UNDERGROUND PIPING AND TANK DESCRIPTION

3.1. INTRODUCTION

Underground piping is all piping that is below grade, inaccessible and outside of buildings. Buried piping (below grade and in direct contact with the soil) is considered to be a subset of underground piping. 'Below grade' denotes locations below standard ground elevation as defined at a station, while 'accessible' denotes piping and tanks that can be routinely observed without special tools or other assistance. This assistance might include removal of permanent security devices or utility access hole covers, use of lifting rigs, excavation, or modification of building structures, armoured embedments or encasements.

Submerged piping is a special type of underground piping; typically, special measures are required to inspect and repair it.

Tanks are fully enclosed stationary vessels used to hold or store fluids for distribution. Underground tanks are all tanks that are outside of buildings and sufficiently below grade² that there is a reasonable possibility that leakage from their inaccessible portions may not be detected. Such tanks may be in direct contact with concrete or located in trenches, underground vaults or tunnels, and may include abandoned tanks connected to active systems. The tanks may include components that are buried as well as those that are not in direct contact with the soil.

3.2. NUCLEAR VERSUS CONVENTIONAL PLANT DIFFERENCES

There are major differences between underground piping in a nuclear power plant and that used in conventional industries. Pipelines used in oil and gas transmission are typically straight, long and electrically isolated, and have a relatively simple infrastructure. In contrast, plant pipes are made of a variety of materials, are often shorter in length, have a far greater range of diameters, have overcrowded infrastructure and are electrically connected and grounded for safety reasons. In order to control ageing mechanisms at nuclear power plants, special consideration must be given to the piping material conditions, coatings and suitable inspection techniques.

3.3. APPLICATIONS WITHIN NUCLEAR POWER PLANTS

Underground piping and tanks are used in both safety and non-safety related applications in a nuclear power plant and may contain liquids or gases. The act of placing a pipe underground can provide protection from certain design basis hazards such as tornado missile strikes. A wide range of systems in a plant can include underground piping and/or tanks. A detailed survey is available for US plants [9].

Applications may include, but are not limited to:

- Fuel and oil handling systems (various types: for diesel/standby generators, lubrication systems, etc.);
- Gas systems (hydrogen, CO₂ nitrogen, service air, miscellaneous gas supply systems);
- Water systems (service water, feedwater, demineralized water, domestic water, fire protection systems);
- Sewage, drains, collection and sampling systems;
- Chemical handling systems (chlorination, dechlorination, boron recycling systems, etc.);
- Electrical systems (those utilizing buried conduits);
- Miscellaneous systems (radioactive waste systems, cooling tower blowdown systems, frazil ice protection, off-gas systems, etc.).

 $^{^2}$ Some jurisdictions (e.g. the US Environmental Protection Agency) consider underground tanks to be those with 10% or more of their volume contained below grade.

Components and structures involved include piping, tanks, tunnels, vaults, supports, anchors, penetrations, air release valves, drains and others. Cathodic protection (CP) systems are often installed as a mitigative measure. See Section 4.10.1 for details on such systems.

A detailed list of systems that may be underground or buried for a typical French pressurized water reactor (PWR) operated by Electricité de France (EDF) is provided in Table 2.

3.3.1. Fuel and oil handling systems

Fuel oil transfer systems provide on-site storage and delivery of diesel or fuel oil to emergency diesel or standby generators. These generators are typically required to operate for several days following design basis accidents, assuming a loss of normal power sources.

Generally, two or three independent trains are provided, each consisting of fuel oil storage tanks, fuel oil transfer pumps and fuel oil day tanks. Newer designs may have storage tanks and transfer pumps located in separate, missile protected, underground vaults. Buried piping in such a system might be utilized between the fuel oil storage tank/fuel oil transfer pumps and fuel oil day tank and between the fuel oil day tank and standby generator.

Bearing oil transfer and purification systems provide storage and transfer of clean and dirty lube oil. The system purifies lube oil contained in the main turbine generator and in large pumps (e.g. feedwater). A typical system would consist of lube oil conditioners, dirty lube oil transfer pumps, lube oil storage tanks (both clean and dirty), lube oil reservoirs, clean lube oil transfer pumps and centrifuge and associated piping. Buried piping in such a system might be utilized between the lube oil storage tanks and turbine building and between the lube oil centrifuge and associated sump.

3.3.2. Gas handling systems

Gas handling systems are used to transport gases such as compressed air, hydrogen, nitrogen, oxygen, helium and carbon dioxide from storage locations to wherever they are needed within a nuclear power plant.

Compressed air systems are generally divided into two subsystems, service air and instrument air. Service air systems provide oil free compressed air for general plant and maintenance use. Instrument air systems provide dry, oil free, compressed air for components and instruments. Additionally, a separate switchyard air system may be installed for electrical switchyards utilizing air blast circuit breakers.

Service gas systems are designed to store and transport hydrogen, nitrogen, oxygen, helium, carbon dioxide or other gases. Hydrogen is typically used for main generator cooling and for chemistry control via hydrogen addition in pressurized heavy water reactors (PHWRs) or chemical and volume control systems (CVCSs; in PWRs). Carbon dioxide is used for main generator purging and fire protection. Nitrogen may be used for purging, pressurization and blanketing and liquid nitrogen for ice plug formation during maintenance. Helium can be used for leak detection, as a cover gas and for liquid zone control in PHWRs.

For these applications buried piping may be found:

- Between compressed air system facilities and end use buildings;
- Between hydrogen storage facilities and turbine/auxiliary buildings;
- Between carbon dioxide storage tanks and turbine buildings;
- Between nitrogen storage tanks (yard area) and each building.

Some BWRs have extensive amounts of buried piping associated with their off-gas systems.

3.3.3. Water handling systems

Water handling systems in nuclear power plants include service water, condensate, demineralized water, circulating water systems, emergency core cooling, chilled water systems, fire protection systems, heavy water transfer (PHWRs), drinking water and others.

Water systems used for cooling plant components may be considered safety related or non-safety related depending on the specific systems involved and their role in safe shutdown of the plant following design basis accidents.

System group	System name	Materials used	
Condenser systems	Circulating water treatment	High density polyethylene (HDPE), carbon steel (CS)	
	Cooling tower forced draft ventilation	Reinforced concrete cylinder pipe (RCCP)	
	Circulating water	Reinforced concrete pipe (RCP), RCCP	
Ventilation and handling equipment	Fuel building handling equipment	304L stainless steel	
Instrumentation and control	Nuclear island liquid radioactive waste monitoring and discharge	304L stainless steel, CS	
Turbine generator	Generator hydrogen supply	304L stainless steel	
Fire protection	Indoor firefighting water distribution	CS, ductile cast iron, cast iron	
	Indoor firefighting water distribution	CS	
	Outdoor firefighting water distribution	Ductile cast iron, cast iron	
Spent fuel pools	Reactor cavity and spent fuel pit cooling and treatment	304L stainless steel	
Reactor systems	Nuclear island vent and drain	304L stainless steel	
General services	Hot laundry and decontamination	304L stainless steel	
	Demineralized water production	Polyvinyl chloride (PVC), CS, composite	
	Demineralization effluents neutralization	304L stainless steel, PVC	
	Demineralization plant water supply	CS, ductile cast iron, cast iron	
	Raw water	PVC, CS, ductile cast iron, cast iron	
	Essential service water	RCCP	
	Conventional island waste oil and inactive water drainage	CS, RCP	
	Industrial water	Ductile cast iron, composite	
	Conventional island liquid waste discharge	304L stainless steel, CS	
	Plant sewer	PVC, composite, RCP, RCCP	
	Potable water	HDPE, PVC, ductile cast iron, cast iron	
	Conventional island demineralized water distribution	HDPE, CS	
	Rainwater drainage	Ductile cast iron, RCP	

TABLE 2. POSSIBLE BURIED OR UNDERGROUND SYSTEMS AT AN EDF NUCLEAR POWER PLANT

System group	System name	Materials used	
	Groundwater control		
	General gas storage	304L stainless steel	
	Hot workshop drainage	304L stainless steel, 316L	
	Auxiliary steam distribution	concrete	
	Conventional island drain and exhaust	304L stainless steel	
Waste treatment	Boron recycle	304L stainless steel	
	Liquid waste discharge	304L stainless steel	
	Solid waste treatment	304L stainless steel	
	Liquid waste treatment	304L stainless steel	

TABLE 2. POSSIBLE BURIED OR UNDERGROUND SYSTEMS AT AN EDF NUCLEAR POWER PLANT (cont.)

Water is normally cleaned, filtered, chemically treated or otherwise obtained outside of the main plant island and buried piping is often used to transfer water to the plant building where it is used. Sample buildings include water treatment plants or screenhouses, which may be included within the plant boundary or operated outside the plant boundary by an external company or municipality. Often local storage tanks for demineralized or emergency cooling water are located on the plant island. Buried or underground piping is typically used as part of the nuclear power plant's connection to its main heat sinks (lake, sea, river or cooling towers).

Yard fire protection systems typically use buried piping and fire hydrants in a ring configuration to make water available for firefighting activities. Such configurations allow for at least two paths for fire water to any given location. Fire protection water supply systems can be gravity or municipality-fed systems, sometimes with local storage tanks, with diesel or motor driven pumps (where needed) taking suction from underground trenches or buried carbon steel (CS) or cast iron piping.

The domestic or drinking water system provides potable water for drinking, showers, laundry and sanitary facilities. Raw water for drinking use is treated in a purification plant and distributed to all fixtures requiring potable water. System layout is designed to prevent contamination due to backflow from cross-connected systems. Domestic water is filtered and treated as necessary, with bacteriological, chemical quality and backflow prevention arrangements conforming to the regulations of the relevant country.

A sample of typical buried piping systems used in water handling systems in a nuclear power plant in the Republic of Korea is given in Table 3.

3.3.4. Sewage, drains and collection systems

Equipment and floor drainage systems are designed to collect drainage. Collected drainage from potentially radioactive equipment and floor drains can be processed in liquid waste treatment systems. Monitoring capability is provided to ensure that inadvertent releases of radioactivity are prevented.

Liquid radioactive waste systems purify radioactive and chemical liquid wastes to allow for their recycling, reuse or disposal.

Equipment and floor drainage systems collect, monitor and direct liquid waste generated within the plant to the proper area for processing or disposal. Systems are typically divided into radioactive and non-radioactive systems. Radioactive and potentially radioactive liquid wastes are drained from equipment and floor drains within containment and other areas potentially containing radioactivity and conveyed to the liquid radioactive waste system for processing. Systems that are not potentially radioactive (e.g. yard and roof drains, sanitary drainage,

TABLE 3. SAMPLE BURIED PIPING INSTALLED IN A NUCLEAR POWER PLANT WATER HANDLING SYSTEM IN THE REPUBLIC OF KOREA

Typical systems	Underground/buried (generally used)	Sample materials used	Fluid
Component cooling water (CCW) system	CCW heat exchanger (Hx) room to primary auxiliary building (PAB)	Carbon steel (CS)	Water
Essential service water system	CCW Hx room to cooling water discharge	CS	Sea water
Condensate storage and transfer (CST) system	CST room to PAB/turbine generator building (TGB)/water treatment building Condensate storage tank to raw water/ demineralized water storage tank	CS/stainless	Water
Make-up demineralizer system	Water treatment building to demineralized water storage tank and each building	CS/stainless	Water
Domestic water system	Water treatment building to each building	Stainless	Water
Raw water system (including fire protection)	Water treatment building to each building	CS	Water
Turbine building open/closed cooling water system	Turbine building CCW Hx room to discharge turbine building to intake	CS	Sea water Water
Chilled water system	Evaporator of water chiller to atmosphere	CS	Water

oily waste and non-radioactive water) are provided with systems for collection and disposal similar to those in non-nuclear conventional facilities.

The importance of floor, storm and yard drainage systems has been highlighted in relation to their role in external flood protection. Degradation of such drainage systems can negatively impact on the ability of stations to respond to heavy rainfall and other similar events.

A sample of typical buried piping systems used in sewage, drains and collection systems in a nuclear power plant in the Republic of Korea is given in Table 4.

3.3.5. Chemical handling systems

Chemical handling systems are used to add, remove or transfer chemicals within nuclear power plants to maintain plant water chemistry within specified requirements. Chemistry control may be required for nuclear safety (e.g. boron, gadolinium content in reactor coolant, moderator or emergency injection systems), or for operational or maintenance reasons. Reasons include pH or dissolved oxygen control (via ammonium hydroxide, hydrazine or other chemicals) to minimize corrosion, control of invasive species such as zebra mussels and minimization of biofouling in condensers, heat exchangers, piping and intake structures.

Depending on chemical aggressiveness, piping and tanks used for such systems may have special requirements and chemical storage areas may be outside of the nuclear power plant main island, necessitating underground connections to end use locations.

Some sample applications of buried piping in PWR chemical handling systems in the Republic of Korea are:

- Between CVCS charging pump, safety injection pump and safety injection tank;
- Between refuelling water tank and holdup tank/pumps;
- Between chlorination (sodium hypochlorite) facilities (building) and intake channel (trench).

TABLE 4. SAMPLE BURIED PIPING INSTALLED IN NUCLEAR POWER PLANT DRAINS AND COLLECTION SYSTEMS IN THE REPUBLIC OF KOREA

Typical systems	Underground/buried (generally used)	Sample material used	Fluid
Liquid radioactive waste system (LRS)	Radioactive waste building to water treatment building/cooling water (CW) discharge	Carbon steel (CS)/ stainless	Water
Radioactive drain	Fuel building decontamination sump to LRS release tank	Stainless	Water
Non-radioactive drain	Fire pump room to wastewater pond (oily) Water treatment building to wastewater pond (chemical)	CS/stainless	Water
Turbine building drain	Turbine building drain to wastewater treatment facilities	CS/stainless	Oil Water
Miscellaneous building drain	Each building sumps to catch basin/storm drainage	CS/stainless	Oil Water
Wastewater transfer	Wastewater pond to wastewater treatment facilities	CS/stainless	Water
Sanitary sewer	Each building to sewage treatment facilities	CS	Water

3.3.6. Electrical systems

Electrical power is supplied from a nuclear power plant switchyard to on-site power systems for electrical auxiliaries through independent circuits. Some plants use an underground conduit, sometimes within concrete encased duct banks, for this purpose.

A buried ground grid is furnished throughout the station to provide personnel safety and equipment protection. Bare copper conductors are of sufficient size to carry the maximum ground fault current. Conductors are located to limit touch and step potentials to safe values under all ground fault conditions, typically meeting IEEE Standard 80-2000 [10] or equivalent requirements.

Plant lighting systems are installed throughout the yard area to provide lighting for personnel safety and security. Typically such systems use embedded steel or polyvinyl chloride (PVC) conduit in combination with direct buried cables for power and control.

Electrical systems also provide power supplies for CP systems used to protect buried metal pipes and other structures from corrosion.

3.3.7. Miscellaneous systems

Condensate polishing systems in a nuclear power plant remove dissolved and suspended impurities from the condensate to maintain water chemistry within specified limits. The system operates during each startup in a recirculation mode to remove corrosion products from the secondary water system. Generally, regeneration waste is discharged to a condensate polishing area sump and transferred to a centralized wastewater treatment system for waste treatment and disposal. Stainless steel buried piping is generally used in such systems.

The steam generator blowdown system is used in conjunction with the chemical feed portion of the feedwater system and the condensate polishing demineralizer system to control the chemical composition and solids concentration in feedwater. Steam generators are maintained in a wet lay-up condition when plant shutdown is expected to be long term. After wet lay-up ceases, steam generators are drained via CS buried piping until the required water quality is met and the desired water level is achieved.

Auxiliary steam systems are designed to provide process steam during plant startup, shutdown and normal operation for equipment located in turbine, auxiliary and radioactive waste buildings. It also provides steam for

decontamination of reactor components and fuel casks. The common boiler supplies steam to an auxiliary steam header during plant shutdown and startup if steam is not available from other sources.

4. UNDERSTANDING AGEING OF UNDERGROUND PIPING AND TANK SYSTEMS

4.1. BACKGROUND

Understanding relevant ageing mechanisms and their potential impact on underground piping is key to an effective, optimized AMP. As Fig. 2 (in Section 2) shows, this understanding links to all programme components. For example, it helps in the definition of:

- Parts of underground piping systems susceptible to degradation;
- Key degradation mechanisms, their symptoms and potential rates of action;
- Impact of degradation on system ability to perform safety functions;
- Appropriate remedial action.

Evaluation of plant condition always calls for informed judgements. Developing the appropriate level of understanding is a continuous process and builds on plant experience. The basis of these judgements is often a review of a generic body of knowledge, supported by a detailed understanding of the mechanisms involved, all put into a plant specific context.

Subsequent parts of this section cover the typical body of knowledge needed to make these informed judgements. This includes an understanding of material properties, methods of construction, stressors, operating conditions, ageing mechanisms, sites of degradation, consequences of degradation, relevant research and development, relevant operating experience, maintenance history, mitigation measures and current piping status.

The ageing process is depicted simply and effectively by a 'bathtub curve' as shown in Fig. 3.

The bathtub curve is characterized by three distinct periods:

— Early life or infant mortality period:

• Failures are mainly due to defective material or poor manufacturing quality control.

- Useful life:
 - Failure rate is often small and approximately constant;



FIG. 3. Typical failure rate bathtub curve [11].

- Some causes of failure during this period are human errors, misapplication and occurrence of higher than expected random loads.
- Wear-out periods:
 - This reflects the ageing process, which results in increasing failure rates.

Failures are often caused by corrosion, ageing, wear and general system deterioration.

4.2. MATERIALS AND FABRICATION

The choice of a specific material for a buried pipe must take into account the operating requirements of the pipeline during its intended operating time. The selected material needs to be able to withstand operational loadings such as thermal and mechanical cycling and, if necessary, extreme loadings, which may raise specific issues for low and high temperatures.

Most buried metal piping is constructed from welded CS (bare, coated or lined) or cast iron (including ductile iron) joined via mechanical joints. Corrosion resistant alloys, including austenitic stainless steels such as types 304 and 316 (including low carbon 'L' grades), more highly corrosion resistant stainless steels (typically the 6% molybdenum stainless steels) and non-ferrous materials, most commonly copper based alloys, including brasses, bronzes and copper–nickel alloys, may also be used for some buried lines. Some plants have installed titanium piping in critical locations. Non-metallic pipe materials such as high density polyethylene (HDPE), PVC and fibre reinforced plastic (FRP) tend to be more commonly used or may be utilized to replace cast iron and steel lines.

Large diameter pipes such as concrete pressure pipes usually have a steel cylinder core which provides water tightness and an outer layer made of reinforced concrete or prestressed concrete which provides mechanical strength.

4.2.1. Metallic pipe materials

Metallic materials that are commonly used in liquid process piping systems can be categorized as ferrous or non-ferrous. Ferrous materials include CS, cast iron, ductile iron, stainless steel and alloys with iron as the principal component. Non-ferrous materials include alloys of nickel, aluminium, copper and lead.

Metallic piping systems other than those addressed in this section are available. Such materials may be used if cost and technical criteria are met.

Common methods for joining metallic pipe include welding and using flanged, threaded and mechanical joints. Mechanical joints include flared, flareless, compression, caulked, brazed and soldered joints. Application requirements and material specifications for these fittings are typically found in the code or standard sections used for specification of the pipe.

4.2.1.1. Steel pipe

Steel pipe is available in various sizes, shapes and wall configurations. For pressure application, the cross-section is circular. However, for gravity flow, steel pipes can have cross-sections that are vertical elongated ellipses, arch shaped (for low head room, called long span arched sections) and other shapes.

Most steel pipes used for gravity applications have a corrugated wall. This produces a larger moment of inertia which results in greater pipe stiffness. Such pipes are usually galvanized for corrosion protection, but are also available as aluminized steel. Common coatings and linings available include bitumen-type materials, Portland cement-type materials and polymers.

Large diameter steel water pipe (SWP) manufactured to American Water Works Association (AWWA) C200 standards does not utilize wires or bars to maintain structural integrity but derives strength from the thickerwalled steel cylinder. It is utilized in low head applications [12] and is engineered and manufactured from steel coil or plates which are formed helically into cylinders or by rolling and welding.

4.2.1.2. Carbon steel

Contact of carbon steel with acid accelerates corrosion. Hydrogen sulphide gas, which is common in wastewater systems, may react directly with CS or be converted biologically to sulphuric acid. CS can be protected by galvanization.

CS is steel in which the main interstitial alloying constituent is carbon in the range of 0.12–2.0%. The American Iron and Steel Institute (AISI) defines CS as [13] steel "when no minimum content is specified or required for chromium, cobalt, columbium [niobium], molybdenum, nickel, titanium, tungsten, vanadium or zirconium, or any other element to be added to obtain a desired alloying effect; when the specified minimum for copper does not exceed 0.40%; or when the maximum content specified for any of the following elements does not exceed the percentages noted: manganese 1.65, silicon 0.60, copper 0.60."

Low-carbon steels contain up to 0.30% carbon; medium-carbon steels are similar to low-carbon steels except that carbon ranges from 0.30 to 0.60% and manganese from 0.60 to 1.65%. Increasing carbon content to approximately 0.5% with an accompanying increase in manganese allows medium-carbon steels to be used in the quenched and tempered condition. High-carbon steels contain from 0.60 to 1.00% carbon with manganese contents ranging from 0.30 to 0.90%.

4.2.1.3. Cast iron

Cast iron is a term applicable to iron possessing carbon in excess of 2% by weight. Compared with steel, cast iron is inferior in malleability, strength, toughness and ductility. On the other hand, cast iron has better fluidity in the molten state and can be cast satisfactorily into complicated shapes. It is also less costly than steel.

4.2.1.4. Ductile iron

Ductile iron is a hard, non-malleable ferrous metal that must be moulded into various component shapes. It has good resistance to general corrosion, but reacts readily with hydrogen sulphide.

Factors that affect properties are given in Ref. [14].

4.2.1.5. Stainless steel

Stainless steels are used where both the properties of steel and corrosion resistance are required. They are alloys of iron, carbon and other elements that contain at least 10.5% chromium by mass. Typically, stainless steels contain no more than 30% chromium and have at least 50% iron content. Other elements such as nickel, molybdenum, copper, titanium, aluminium, silicon, niobium, nitrogen, sulphur and selenium are added to improve specific characteristics (such as corrosion resistance) [15].

The chromium in stainless steels allows it, in the presence of oxygen, to undergo passivation, which is the formation of an inert film of chromium oxide on its surface. This layer prevents further corrosion by blocking oxygen diffusion to the steel surface and stops corrosion from spreading into the bulk metal.

Stainless steels are commonly divided into five groups:

- Martensitic;
- Ferritic;
- Austenitic;
- Duplex (ferritic-austenitic);
- Precipitation hardening.

The most common types of stainless steel used in buried piping are 304 and 316. Types 304 and 304L are austenitic stainless steels that provide outstanding resistance to bases and are highly resistant to many acids. Types 316 and 316L, stainless steels exhibiting better resistance to sulphides and chlorides than 304 and 304L, will provide adequate resistance to corrosion from sulphuric acid. Otherwise, 316 and 316L provide the same resistance to acids and bases as 304 and 304L.

The 'L' designation indicates that the carbon content of the alloy is below 0.03%. Such alloys were developed to minimize post-welding intergranular corrosion. These alloys are strongly recommended whenever welding is involved. In general, 'L' stainless steels provide more resistance to sulphuric acid/nitric acid mixed solutions than steels with higher carbon content.

Superaustenitic stainless steels, with more than 6% molybdenum and increased nickel and nitrogen levels, are very resistant to chloride pitting, crevice corrosion, microbiologically influenced corrosion (MIC) and chlorideinduced corrosion. For this reason they are in use, or under consideration for use, as replacement buried piping at nuclear power plants [16].

4.2.1.6. Low alloy steels

Technically, every type of steel is an alloy steel since it contains iron and a small amount of carbon (less than 1%). However, the standard terminology 'alloy steel' is used for referring to steel containing iron, carbon and other alloying elements, such as manganese, phosphorus, sulphur, silicon, nickel, chromium, molybdenum, copper, titanium, vanadium and niobium. Low alloy steels have less than 8% alloying elements.

Use of these alloying elements improves steel properties such as strength (copper, titanium, vanadium, niobium, silicon), hardness (titanium), toughness (nickel, vanadium), hardenability (boron, chromium, manganese), wear resistance, corrosion resistance (copper, silicon, nickel, chromium, phosphorus) and formability (zirconium, calcium). Chromium is known to provide very good protection from flow accelerated corrosion (FAC).

See ASTM A350 [17] for further information on low alloy steels.

High strength low alloy steel (HSLA) is a low alloy steel with a reduced carbon content (less than 0.27%) to improve weldability and formability while keeping its strength. Yoloy is an HSLA with enhanced corrosion resistance. See ASTM A714 [18] for further information.

4.2.1.7. Aluminium and aluminium alloys

Some nuclear power plants have used aluminium buried piping in their condensate systems to minimize the iron content in high-purity water systems; however, leaks have occurred in several locations. [16].

Aluminium is generally highly resistant to corrosion under the majority of service conditions. In certain specialized applications, such as fabrics in the textile industry and solutions in chemical equipment, it has the advantage of not forming any coloured salts, which can stain adjacent surfaces or discolour products with which it comes into contact.

4.2.1.8. Copper and copper alloys

Copper is a very ductile and malleable metal and does not corrode easily in normal wet/dry environments. However, copper corrodes rapidly when exposed to oxidizing agents such as chlorine, ozone, hydrogen sulphide or nitric acid.

Copper is very susceptible to galvanic action and this demands that padded pipe hangers be used and that attention be paid to contact with dissimilar metals.

Factors that affect properties are listed below [19].

- Corrosion resistance of copper:
 - All copper alloys resist corrosion by fresh water and steam;
 - Copper is resistant to saline solutions, soils, non-oxidizing minerals, organic acids and caustic solutions;
 - Moist ammonia, halogens, sulphides, solutions containing ammonia ions and oxidizing acids, like nitric acid, will attack copper. Copper alloys have poor resistance to inorganic acids.

— Ductility:

• Can be restored by annealing.

— Strain hardening:

• Application of cold work, usually by rolling or drawing, hardens copper and copper alloys. Strength, hardness and springiness increase while ductility decreases;

- Conductivity is reduced to a small extent, normally not to the extent that it hinders use of the alloys in electrical products;
- Effects of cold work can be removed by annealing, in which case full conductivity returns.
- Solid-solution hardening:
 - Alloying elements that remain dissolved in solidified copper strengthen the lattice structure;
 - All dissolved additions to copper reduce electrical conductivity, making the balance between strengthening gained and conductivity lost necessarily a compromise.

4.2.1.9. Nickel and nickel alloys

Nickel is used for its strong resistance to certain corrosive chemicals. Monel, a nickel–copper alloy, combines high strength with high ductility, as well as excellent general corrosion resistance. It is specified particularly where sea water or industrial chemicals may be accompanied by high temperatures. It must not be exposed, when hot, to sulphur or molten metals. Inconel, a nickel–chromium–iron alloy, is noted for having high temperature strength, while maintaining excellent corrosion resistance.

4.2.2. Non-metallic pipe materials

Non-metallic pipes such as HDPE, PVC or FRP are commonly used and may be utilized to repair or replace steel lines. However, a direct comparison of material properties between thermoplastics and metal is undesirable due to the variations in application and associated material responses.

Temperature, environment and duration of loading may alter the stress-strain response, rupture strength and ultimately strain capacity. Moreover, mechanical properties vary from one class of thermoplastic material to another (e.g. between PVC and HDPE) and also within the same type of material, depending on its constituents and the manufacturing process.

4.2.2.1. High density polyethylene

Although not a markedly less expensive material in itself (in larger pipe sizes), high density polyethylene (HDPE) is much less expensive to install than CS piping due to its light weight and ease of handling (see Fig. 4). It is immune to service water corrosion, is highly resistant to fouling and can withstand normal operating temperatures up to 60°C, including short term accident transients up to 80°C.

HDPE used in buried pipe applications is typically bimodal, non-cross linked HDPE, as opposed to cross linked HDPE which is typical of chemical tank applications. Cross linked HDPE uses thermoset resins that cannot be fused. Non-cross-linked HDPE uses thermoplastic resins that can be fused. Proper material selection, control of manufacturing (typically extrusion) and field fabrication are important to reliable applications.

HDPE piping has numerous positive characteristics when compared to metal piping. For installation these include it being lightweight, easier to bend, cheaper to install, easier to install via trenchless technologies and



FIG. 4. Example showing degradation resistance of high density polyethylene piping [20].

having joints that are as strong as or stronger than the pipe itself (see Fig 5). Once in service the piping does not corrode, maintains optimum flow rates (e.g. is not susceptible to tuberculation or scale) and has fewer leaks (e.g. excellent water hammer characteristics and virtually no breakage due to freezing) [21].



FIG. 5. High density polyethylene is flexible (courtesy of EPRI) [22].

HDPE is suitable for use in low temperature, low pressure process fluid applications and other industrial services throughout the balance of plant (BOP). The American Society of Mechanical Engineers (ASME) Code Case N-755-1 [23] has been written for Section III [24] and Section XI [25] applications. Where the code case is not directly applicable due to changes in joining techniques and/or material properties, some utilities have been successful in obtaining approval to use such piping by invoking additional sampling and in-process destructive testing during pipe installation [26].

HDPE is sensitive to slow crack growth (SCG), improper fusion and ultraviolet (UV) radiation.

Fabrication is performed by thermal fusion and can be performed more rapidly than steel welding. HDPE pipes or fittings can be joined (welded) together by many methods of heat fusion or by mechanical flange fittings. Types of heat fusion joints include butt fusion, saddle/sidewall fusion, socket fusion and electrofusion. HDPE creeps under load, so flanged joints need to be retorqued.

Fusion introduces heat into the elements to be joined, then applies pressure under controlled conditions between the heated elements, causing the polyethylene to fuse together. After cooling, the joint area is as strong as or stronger than the pipe elements themselves. Butt fusion, saddle/sidewall fusion and socket fusion welds are similar in that each applies heat to the areas to be joined using some kind of heating element. Force is then applied to fuse the elements together and to hold them immobile until they cool. Electrofusion uses a coupling with embedded heating wires that are supplied with an electric current to produce heat. Expansion of the piping elements inside the coupling produces the force to fuse the elements together where they are held immobile until cool. Figure 6 shows a typical fusion machine.

4.2.2.2. Polyvinyl chloride

PVC is a widely produced plastic. It is commonly used in construction because it is often cheaper and easier to install and maintain than traditional materials such as copper, iron or wood in piping and applications requiring rigidity (e.g. door and window frames, partitions, siding) (Fig. 6). In electrical applications it can be plasticized for use in flexible PVC-coated wire and cable.

Rigid PVC is stronger and stiffer than HDPE, thus PVC pipes require longer bending radii, but also less material to achieve or meet desired strength levels. PVC pipes are stiff enough to permit direct connection to mechanical valves, non-plastic fittings and various other water and wastewater appurtenances (Fig. 7) and



FIG. 6. Butt fusion weld machine for high density polyethylene pipe (courtesy of EPRI) [21].



FIG. 7. An example of polyvinyl chloride pipe (Blue Brute) suitable for new construction or as a repair/replacement material for connecting to old cast iron pipe (courtesy of Ipex Inc.) [27].

have been used in applications such as underground fire line repair in nuclear power plants (e.g. Ontario Power Generation's Pickering Nuclear Generating Station).

PVC's properties are highly temperature dependent. As shown in Fig. 8, PVC's impact strength drastically decreases with temperature. The blue area in Fig. 8 reveals a significant decrease in impact strength as the temperature gets colder; the PVC is becoming increasingly brittle. This phenomenon is one that is not seen with metals and may be overlooked when designing with plastics. The green curve presents the PVC modulus as a function of temperature. The green dashed line shows the transition zone towards a dramatic decrease in stiffness (around 50°C in this example).

PVC can be enhanced with additives in order to give it higher impact strength at low temperatures; however, this results in lower stiffness (the green curve will tend to move to the left, lowering the temperature when stiffness is lost). Thus, a compromise between impact strength and stiffness must be made, depending on application requirements.



FIG. 8. The influence of temperature on polyvinyl chloride properties [28].

4.2.2.3. Acrylonitrile-butadiene-styrene pipes

Acrylonitrile-butadiene-styrene (ABS) pipes are widely used for drain, waste and vent piping. They can be used to a very limited extent for small diameter pressure piping.

Design methods and procedures are essentially the same as those for PVC pipes, with the appropriate elastic modulus used for calculating pipe stiffness and the appropriate hydrostatic design stress for pressure pipe design.

4.2.2.4. Other thermoplastic pipes

In addition to the thermoplastic piping materials discussed previously, there are other types of thermoplastic piping materials which are used to a lesser extent. These materials include polybutylene (PB), cellulose acetate butyrate (CAB) and styrene rubber.

4.2.2.5. Fibre-reinforced plastic

Fibre-reinforced plastic (FRP) is a composite material made of a polymer matrix reinforced with fibres. The polymer is usually an epoxy, vinylester or polyester thermosetting plastic while the fibres are usually glass, carbon, basalt or aramid.

In contrast to metals, where the fracture process is known to result from nucleation and subsequent growth of a single dominant crack, fibre-reinforced composite laminates are characterized by the initiation and progression of multiple failures of different modes. Consequently, there are many more potential failure modes for composite laminates than for metallic materials. They thus have to be analysed in detail for better understanding of their failure [29].

FRP allows for the alignment of thermoplastic glass fibres to suit specific designs. Specifying a reinforcing fibre orientation can increase polymer strength and deformation resistance. Details on FRP properties can be found in Ref. [30].

Some fire codes, such as NFPA 1 [31] and NFPA 30 [32], allow non-metallic piping to be used underground for flammable liquid transport in small diameters. Underground steel piping would require CP systems and inherent periodic testing. FRP piping is therefore a cost effective alternative to underground steel piping with CP.

4.2.2.6. Glass reinforced plastic

Glass reinforced plastic (GRP) or glass-fibre reinforced plastic (GFRP) is a fibre reinforced polymer made of a plastic matrix reinforced by fine glass fibres. It is lightweight, extremely strong and robust. Although its strength properties are somewhat lower than carbon fibre and it is less stiff, the material is typically far less brittle than carbon fibre and the raw materials are much less expensive. Bulk strength and weight properties are very favourable when compared to metals and it can be easily formed using moulding processes.

Different types of glass are used for reinforcing fibres, each type being distinguished by its chemical composition. Some key glass fibre properties are given in Table 5. Low-alkali E glass is used most frequently for reinforced plastics while R and S glass have better mechanical and thermal properties.

Type of fibre		Density (g/cm ³)	Tensile strength (MPa)	Modulus of elasticity (MPa)	Melting point (°C)	
	E glass	2.52	2400	73 000	700	
Glass	R glass	2.55	3600	86 000	800	
	S glass	2.50	3400	88 000	840	
	High modulus	1.90	2000	500 000		
C 1	High strength	1.75	2500	240 000	T. (1	
Carbon	Aramid	1.45	3200	133 000	Temperature limit 230	
	Boron	2.63	3200	420 000		

TABLE 5. PROPERTIES OF GLASS AND CARBON FIBRES [33]

4.2.2.7. Clay pipe

Vitrified clay is very corrosion and abrasion resistant. Because of its inherent low strength, vitrified clay piping is used for non-pressure applications only. It is brittle and subject to impact damage; therefore, special care in handling is required.

4.2.3. Concrete pressure pipe

These pipes are described in AWWA M9 [34] and are briefly presented in this section. Concrete piping usually falls into five different types, as listed in Table 6.

4.2.3.1. Prestressed concrete cylinder pipe

Prestressed concrete cylinder pipe (PCCP) (AWWA C301 [35]; see Fig. 9) is a widely used type of concrete pressure pipe. It has an inner layer of concrete, a steel cylinder and an outer layer of prestressed concrete. Mechanical strength is provided via prestressing wires (which prestress the concrete core) and a steel cylinder that provides a leaktight membrane.

PCCP has two general types of construction: a steel cylinder lined with a concrete core, called lined cylinder pipe (LCP), and a steel cylinder embedded in a concrete core, called embedded cylinder pipe (ECP).

PCCP's prestressing wires are wrapped outside of the steel cylinder and protected by an approximately 1.9 cm thick mortar coating. Concrete core thickness is at least one sixteenth of the inside pipe diameter. The pipe is considered essentially rigid as it undergoes minimal deflection under earth and other applied loads.

Туре	History	Scope of use	Typical available diameter	Typical available length	Typical use
Reinforced concrete non-cylinder pipe (RCNP)	Manufactured since 1900 in response to unsanitary sewer system issues	Designed for low internal pressure (up to 379 kPa) Limited in external load capacity	300–3600 mm	2.5–7 m	Domestic raw water supply and discharge lines; sanitary
Reinforced concrete cylinder pipe (RCCP)	Manufactured since 1940. Steel cylinder core provides water tightness while outer reinforced concrete layer provides mechanical strength	Designed for high internal pressure (over 2758 kPa) Limited in external load capacity	600–3600 mm	4–7 m	Water intake and discharge lines; pressure lines; sewer lines
Prestressed concrete cylinder pipe (PCCP)	PCCP is an evolution of RCCP and has been manufactured since 1942	Designed for high internal pressure (over 2758 kPa) and external load capacity (earth cover in excess of 30 m)	Lined: 400–1500 mm Embedded: 1.2–6.3 m	5–7 m	Water intake and discharge lines; pressure lines; sewer lines
Concrete bar-wrapped cylinder pipe (BWP)	Manufactured since 1942. While BWP looks like PCCP in cross-section, its design and materials are different. PCCP remains under compression because of prestressing wires whereas in BWP the cylinder plays a key role in structural integrity.	Designed for high internal pressure (over 2758 kPa) or external load capacity	250–1800 mm	7–12 m	Distribution feeder mains; sewer force mains; water intake and discharge lines
Polymer concrete microtunnelling pipe	Developed in the 1960s in Germany, but not in general use until the 1980s. Made from thermosetting resin, sand, gravel and mineral fillers. Has load carrying capability of reinforced concrete with anticorrosive characteristics (pH 1–10 range)		15 mm to 3m	0.9–3m	Sewers/corrosive environments by microtunnelling; trenchless renovation (e.g. sliplining); or direct burial new installation

TABLE 6. TYPICAL TYPES OF CONCRETE PIPE

PCCP has been designed for operating pressures greater than 2758 kPa and earth covers in excess of 30 m. AWWA has issued a standard for its design (AWWA C304 [36]).

4.2.3.2. Reinforced concrete cylinder pipe

Reinforced concrete cylinder pipe (RCCP) (AWWA C300 [37]; see Fig. 10) is similar to PCCP but has an outside layer made of reinforced concrete instead of prestressed concrete. Steel cylinders are usually thicker in an RCCP than in a PCCP.

Maximum loads and pressure depend on pipe diameter, wall thickness and the strength limitations of concrete and steel. This pipe may be designed for high internal pressure but is limited in external load capacity.



FIG. 9. Schematic pipe wall cross-sections for lined and embedded cylinder pipe [34].



FIG. 10. Reinforced concrete cylinder pipe (AWWA C300): (left) courtesy of EDF; (right) courtesy of Ref. [34].

4.2.3.3. Reinforced concrete non-cylinder pipe

Reinforced concrete non-cylinder pipe (RCNP) (AWWA C302 [38]; see Fig. 11) is suitable for low working pressures (less than 379 kPa). It may have either steel bell and spigot joints or concrete bell and spigot joints with rubber gaskets.

4.2.3.4. Concrete bar-wrapped cylinder pipe

Concrete bar-wrapped cylinder pipe (BWP) (AWWA C303 [39]; see Fig. 12) is manufactured with a steel cylinder wrapped with a smooth, hot-rolled steel bar, using moderate bar tension. Bar size and spacing, as well as steel cylinder thickness, are proportioned to provide the required pipe strength. The cylinder and bar wrapping are covered with a cement slurry and a dense cement-rich mortar coating.

4.2.3.5. Polymer concrete microtunnelling pipe

Polymer concrete microtunnelling pipe is a high strength, corrosion resistant, rigid pipe suitable for trenchless technology. It can be used for microtunnelling applications, trenchless renovation (e.g. sewer sliplining), or as direct burial piping for new installations. The pipe is corrosion resistant without any lining or coating. Original development of the technology began in Germany in the 1960s, but it was used infrequently until 1986 when adequate production facilities became available. Two of its main manufacturers are Meier Betonwerke GmbH and HOBAS Rohre GmbH. Over 200 000 m of this type of piping have been installed worldwide [40]. The pipe



A. ANSI/AWWA C302-Type Pipe With Steel Joint Rings



B. ANSI/AWWA C302-Type Pipe With Concrete Joint Rings

FIG. 11. Reinforced concrete non-cylinder pipe (AWWA C302) [34].



FIG. 12. Concrete bar-wrapped cylinder pipe (AWWA C303) [34].

has high compressive strength, allowing for the use of high jacking force during installation, high elasticity, low weight and is corrosion resistant over a wide range (pH 1.0 to 10.0). Applicable product standards are DIN 54815-1 [41] and 54815-2 [42]. The pipe is referred to in the American Society of Civil Engineers (ASCE) standard for microtunnelling [43].
4.2.4. Speciality pipe

4.2.4.1. Double containment pipe

A double containment pipe (DCP) is composed of a primary carrier pipe, protected by a secondary pipe which provides containment for purposes of environmental protection or safety (Fig. 13). Applications include fuel systems and some radioactive waste systems.

Usually, DCPs have spacers/centralizers that keep the containment pipe concentrically supported to the carrier pipe. The space between both pipes is called the interstitial/annular space.

To provide secondary containment for piping systems, some design considerations need to be taken into account. Whether the buried pipeline will be, for example, a pressure transfer pipe or a drain or waste line will have a significant impact on the design of the DCP.

The material for inner (primary) piping should be selected based on its ability to withstand the corrosive effects of the inner fluid. The same design techniques and criteria used for selecting materials for single-walled piping systems are used for primary piping. However, the interaction with the secondary piping has to be taken into account when defining the joining method. Thus the interaction between both pipes has to be studied extensively.

For outer (secondary) piping, material considerations must include the risk and impact of the secondary piping being in contact with a contaminated fluid. Since the duration and frequency of this contact will be very low, use of a less expensive material for the secondary piping may be appropriate. However, in some cases the probability of a double failure might be too great to risk using less corrosion resistant material.

Leak detection in a DCP usually consists of systems to monitor the space between both pipes, usually by measuring for the presence of a leaked fluid.



FIG. 13. Section of double containment pipe.

4.2.4.2. Electrical conduit

Electrical conduit is electrical piping used for the protection and routing of electrical wiring. Electrical conduit can be metallic or non-metallic (plastic, fibre, fired clay, etc.). Flexible conduit is available for special purposes. Typical types of electric conduit are listed in Table 7.

Conduit may be installed underground between buildings, structures or devices to allow installation of power and communication cables. An assembly of these conduits, often called a duct bank, may either be directly buried in earth or encased in concrete (sometimes with reinforcing rebar to protect against shear). A duct bank allows for the easy replacement of damaged cables between buildings, or the addition of more power and communications circuits, without the expense of re-excavating a trench. While metal conduit is occasionally used for burial, PVC, polyethylene or polystyrene plastics are now usually used due to their lower cost and easier installation.

4.2.4.3. Cased piping

Some pipelines are installed inside casings beneath roadways, railroads and other locations (Fig. 14). Similar to an electrical conduit, the casing is designed to protect the installed pipe from mechanical damage (e.g. overburden

Classification	Name	Description
Metallic	Rigid metal conduit (RMC)	Thick threaded tubing usually made of coated steel, stainless steel or aluminium
	Galvanized rigid conduit (GRC)	Galvanized steel tubing, with a tubing wall that is thick enough to allow it to be threaded. Its common applications are in commercial and industrial construction.
	Intermediate metal conduit	Steel tubing heavier than EMT but lighter than RMC. It may be threaded.
	Electrical metallic tubing (EMT)	Sometimes called thin-wall, it is commonly used instead of GRC, as it is less costly and lighter than GRC. EMT may not be threaded, but can be used with threaded fittings that clamp to it. Lengths are connected with clamp- type fittings. Like GRC, EMT is more common in commercial and industrial buildings than in residential applications. EMT is generally made of coated steel, though it may be aluminium.
	Aluminium conduit	Similar to GRC, generally used in commercial and industrial applications, where a higher resistance to corrosion is needed. Cannot be used in contact with concrete due to alkali reaction.
	Stainless steel, bronze or brass conduit	Used in extreme corrosion environments where plastic coating of the tubing is insufficient
Non-metallic	PVC	Typically the lightest and least expensive of conduit types, it is suitable for embedded use in concrete, and, for heavier grades, for direct burial and exposed work. It resists moisture and many corrosive substances, but since the tubing is non-conductive an extra bonding (grounding) conductor must be often pulled into each conduit. PVC conduit may be heated and bent in the field.
	Rigid non-metallic conduit	Non-metallic unthreaded tubing
	Electrical non-metallic tubing (ENT)	Thin-walled corrugated tubing that is moisture resistant and flame retardant. It is pliable such that it can be bent by hand and is often flexible although the fittings are not.
Flexible	Flexible metallic conduit (FMC)	Made by helical coiling of a self-interlocked ribbed strip of aluminium or steel, forming a hollow tube through which wires can be pulled. FMC is used primarily in dry areas where it would be impractical to install EMT or other non-flexible conduit, yet where metallic strength to protect conductors is still required.
	Liquid tight flexible metal conduit	Metallic flexible conduit covered by a waterproof plastic coating. Interior is similar to FMC.
	Flexible metallic tubing (FMT)	Not the same as FMC. FMT is a raceway, but not a conduit.
	Liquid tight flexible non- metallic conduit	Refers to several types of flame resistant non-metallic tubing. Interior surfaces may be smooth or corrugated. There may be integral reinforcement within the conduit wall. It is also known as FNMC.

TABLE 7. TYPICAL TYPES OF ELECTRICAL CONDUIT



FIG. 14. Cased pipeline schematic showing spacers (courtesy of PSI Products GmbH).

for deep pipe, live loads (traffic) and third-party damage) and to provide capability to remove or replace the inside carrier pipeline without disturbing the road or rail-crossing. They can also be used to direct any volatile or hazardous fluids that might leak from the carrier pipe to a safe distance away from beneath the thoroughfare.

Utility lines that run through casing pipe are commonly mounted and spaced using spacers made of various materials, including stainless steel, CS or plastic. Ends of a casing pipe run are normally sealed. A casing's annulus can either be dry/empty or filled (with a wax or other substance).

Use of casings requires additional design and construction costs, additional maintenance and monitoring of electrical isolation. They also can induce problems associated with electrical shorts and increased loads on CP systems. If the annular space between the pipe and casing becomes filled with an electrolyte, possible corrosion mechanisms include electrical shielding, crevice corrosion associated with non-metallic casing spacers and pipe corrosion at coating flaws. If there is an electrical short between the pipeline and casing, the casing may appear as a large coating flaw on the pipeline, consume the available CP current and reduce CP effectiveness at other locations along the pipeline. For these reasons use of pipe casings is declining and discouraged in many standards (see e.g. para. 7.5.1 of Ref. [44]).

4.2.5. Tanks

Underground storage tanks (USTs) are constructed primarily of metals (steel or aluminium), composites (glass or FRPs), or flexible plastics. CS followed by stainless steel are the most common tank materials found at nuclear power plants. Composite or plastic materials where utilized can be used alone or in a variety of combinations. Some of these combinations can include:

- Composite overwrapped metallic: aluminium/steel tanks with filament windings (fibreglass/aramid or carbon fibre or a plastic compound) around the metal cylinder for corrosion protection and to form an interstitial space;
- Composite material with metal liner: fibreglass/aramid or carbon fibre with aluminium or steel liner;
- Composite with polymer liner: carbon fibre with a thermoplastic polymer liner.

A complete tank system can consist of the tank itself, spill and overflow protection systems (e.g. shut-off valves, overfill/spill alarms), release detection systems (e.g. groundwater monitoring, soil vapour monitoring, tank interstitial space monitoring, level measurements), corrosion protection methods (e.g. use of a specific tank material, CP systems, interior linings), vent systems and dispensers (e.g. for dispensing fuel oil to vehicles). The extent to which additional systems are present typically depends upon tank contents and what specific regulations may apply to prevent and clean up releases from such tanks.

USTs do not include non-enclosed outside fluid containments such as basins, ponds or reservoirs [45]. Some examples of USTs are shown in Fig. 15.

Tanks that are considered pressure vessels must be designed and certified as required by design codes such as the ASME Boiler and Pressure Vessel Code [46], the pressure equipment directive of the EU (PED) [47], French



FIG. 15. Typical tanks: (left) metallic STI-P3 storage tanks (dual wall, coated, with pre-installed cathodic protection anodes; courtesy of the Steel Tank Institute [52]); (middle) STI ACT-100 steel tank with fibreglass coating (courtesy of the Steel Tank Institute); (right) glass fibre reinforced plastic fuel tanks being installed at an airport (courtesy of AOC Resins Inc. [53]).

standards (AFCEN) [48, 49], CSA B51 [50] in Canada, Japanese Industrial Standards (JIS) such as JIS B8265 [51] and other international standards.

4.2.6. Coatings

Protective or barrier coatings can be applied to both pipes and tanks. They function by three main mechanisms: (1) providing a barrier to the environment, (2) providing corrosion-inhibitive pigments (e.g. zinc phosphate primers) and (3) providing electrochemical/galvanic action (e.g. galvanizing or zinc silicate paints). All coatings operate by barrier action and some in addition by one of the other two mechanisms. Application of coatings can reduce current requirements for CP systems and improve CP system current distribution [16].

A single pipe may utilize a number of different coatings along its length: the underground coating portion would cover the bulk of the underground system; a transition area coating would be used where piping transitions from buried service to atmospheric service to protect from mechanical damage (e.g. freeze-thaw cycles, industrial equipment, gravel) and UV light; and an atmospheric coating would be used primarily for corrosion prevention, but with a secondary purpose of having a good appearance.

As well as providing protection against corrosion, coatings may need to have other properties such as being resistant to fire, able to withstand radiation, suitable for decontamination, non-toxic when in contact with drinking water, etc. A perfect coating would be easy to apply, inexpensive, non-toxic and last forever; however, in practice coating selection requires trade-offs between these parameters.

Coatings may be classified into three main categories: organic, inorganic and metallic. These categories can be subdivided according to coating constituent parts and/or application methods. The classification system adopted in this publication is shown in Fig. 16. Detailed descriptions of coating types can be found in the subsections that follow.

4.2.6.1. Organic coatings

Organic coatings, applied on properly pretreated surfaces, are the most common and effective mode of corrosion protection for metallic objects and structures.

(a) Organic coating structure

Long lasting coating systems often consist of a primer, a set of intermediate or body coats and a topcoat.



FIG. 16. Coating classification.

Primers adhere to prepared base metal and provide a surface for strong bonding of intermediate coats. They can retard the spread of corrosion discontinuities such as pinholes or coating holidays.

Intermediate or body coats are applied when coating thickness and structure are a benefit. They can provide desired thickness, chemical and moisture resistance, electrical resistance, cohesion and a good surface for application of topcoats.

Topcoats provide a seal over the body coats and primer and are the first defence against chemicals and external environments. They tend to be denser than body coats and can provide toughness and wear, mildew or biological resistance to the coating. Sample topcoats include air-drying paints and oil based varnishes, acrylics, lacquers and polyurethane and epoxy paints.

(b) Organic coating components

Organic coatings consist of three basic components: (1) solvent, (2) pigment and (3) binding resin. The solvent and resin are often referred to together as the 'vehicle' as they transport and bind the pigment to the surface being protected.

Not all coatings contain solvent and pigmented components. There are solvent free and clear, pigment free coatings but no binding resin free coatings.

Solvents are made to dissolve binding resin, control evaporation for film formation and reduce coating viscosity for ease of application. Solvents produce vapours that are heavier than air which can collect in low lying areas such as tank bottoms. As solvents dry they can release volatile organic compounds, which are increasingly subject to environmental regulation. The trend, therefore, has been to reduce the levels of solvents in coatings. Most coatings that use solvents use multiple solvents to achieve the desired properties. Typical solvents include hydrocarbons (e.g. naphtha, mineral spirits, toluene, xylene), ketones (e.g. acetone, methyl ethyl ketone), esters, alcohols, ethers and water.

Pigments are additives to coating formulations that impart specific properties such as corrosion resistance, colour, weather and moisture resistance, mechanical strength enhancement, skid or slip resistance and opacity protection (e.g. against UV) or fire retardance. They are insoluble and are the solid parts of a coating. Some typical pigments and their uses are listed in Table 8.

Desired property	Typical pigment	Comment
Corrosion resistance	Chromate and lead pigments Barium metaborate Calcium phosphosilicate Zinc phosphate Zinc molybdate Zinc phosphosilicate	Chromate and lead pigments are no longer used because of environmental and health concerns Zinc phosphate is probably the most important pigment for anticorrosive paint
Colour	Natural earth pigments (kaolin, clay, magnesium silicate, calcium carbonate)	Provide colour stability from UV. More stable than synthetic organic pigments.
Opacity	Titanium oxide	Hides substrate or previous coating colour; protects binder from UV
Wet paint	Silica and talc	Control viscosity. Wet film levelling and settling. Little opacity control.
Weather and moisture resistance	Aluminium leaf & micaceous iron oxide	Increase barrier thickness
Mildew resistance	Mildewcides	
Skid or slip resistance	Aluminium oxide Mineral aggregate	Aluminium oxide better choice as it does not crush under weight

TABLE 8. TYPICAL PIGMENTS (BASED ON REF. [54])

Pigments may have differing levels of performance based on their exposed environment. Table 9, for example, presents the characteristics of common metallic pigments used for corrosion resistance versus exposure to various environments.

Generic type	Common name	Alkali	Acid	Water	Weather	Physical characteristics
Aluminium	Aluminium flake	NR	NR	Е	Е	Creates shingle effect, protects binder and increases moisture upon transfer resistance.
Stainless	Stainless flake	Е	Е	E	G	Does not leaf as well as aluminium flakes. Reinforces binder without reducing chemical resistance.
Lead	Lead flake	Е	Е	E	Е	Does not leaf as well as aluminium flakes. Excellent chemical and water resistance.
Copper	Copper flake	NR	NR	G	F–G	Leafs well, good copper colour, chemical resistance only fair. Has a good antiflaking property.
Zinc	Zinc flake	NR	NR	Е	Е	Provides some CP to steel. Reinforces some organic binders. May be used with zinc powder for reinforcing purposes.

TABLE 9. METALLIC PIGMENTS USED FOR CORROSION RESISTANCE [55]

Notes: E - excellent; G - good; F - fair; NR - not recommended.

Binding resins or **binders** are the film forming component of a coating. A binder is typically a high molecular weight solid polymer that forms large repeating molecules in the cured film. The resin determines most coating properties. Various resins formulated in a coating will display distinct properties such as performance in service exposure, performance on substrate, compatibility with other coatings and adhesion. Coatings may have more than one binder to successfully meet each of these criteria.

Coatings are usually classified by the primary resin type used (primer). Typical resins are acrylics, alkyds and epoxy polymers. Binders can also be classified according to their essential chemical reactions. Detailed information regarding organic coating binders classified by related chemical reactions is included in Appendix II.

A binder's ability to form a dense, tight film is related to its molecular size and complexity. Binders that have the highest molecular weight will form films by evaporation of the vehicle, whereas binders with smaller molecular weight will generally react in situ [56].

Coatings must be evaluated as compatible with their desired primer to ensure proper adhesion and long term durability. Qualification of the primer, coating and surface combination is essential to ensure proper performance and adequate corrosion control. Table 10 provides some typical examples of primer-coating combinations.

(c) Organic zinc coatings

Zinc rich paints contain 65-95% metallic zinc in dry film, with 92-95% being common. They can be brushed or sprayed onto steel to a dry film thickness of $64-90 \mu$ m. Application can be either in the factory or on the job site.

Organic zinc coatings may be a zinc rich alkyd, drying oil, epoxy or moisture-cured urethane depending on the solvents and resins used. These provide galvanic protection or are used to repair damaged galvanized coatings. Organic zincs are specified for atmospheric, burial and immersion service exposures and are normally topcoated to extend service life.

The properties of organic zinc rich paints depend on the solvent system. Multiple coats may be applied within 24 hours without cracking. Organic zinc rich paints do not have the same temperature resistance of inorganic zincs, as they are limited to 80–150°C. They are also subject to UV degradation and are not as effective as inorganics in corrosion resistance.

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Primers	Alkyd	Alkyd, phenolic	Vinyl alkyd	Vinyl	Vinyl acrylic	Epoxy, catalysed	Epoxy, ester	Coal tar epoxy	Chlorinated rubber	Phenolic, oleo-resinous	Polyurethane	Polyester flake or glass
Alkyd	R	R	NR	NR	NR	NR	NR	NR	NR	R	NR	NR
Bituminous (aluminium) ^a	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Vinyl alkyd ^b	R	R	R	R*	R*	NR	R	NR	NR	NR	NR	NR
Vinyl ^b	R	R	R	R	R	NR	NR	NR	Я	NR	NR	NR
Epoxy, ester	R	R	NR	NR	NR	NR	R	NR	Х	R	NR	NR
Epoxy, catalysed ^c	NR	NR	R*	$R^{\ast (\mathrm{d})}$	R*	R*	R*	R*	Х	NR	R*	R*
Epoxy, non-catalysed ^c	R	R	R	Х	X	R	R	X	Х	R	NR	R*
Epoxy, organic zinc ^c	NR	NR	NR	R*	NR	R	R	R	R	NR	NR	NR
Phenolic oleoresinous	R	R	NR	NR	NR	NR	К	NR	NR	R	NR	NR
Vinyl, phenolic	R	R	R	R	R	NR	R	NR	Я	R	Х	NR
Coal tar epoxy	NR	NR	NR	\mathbf{NR}^{d}	NR	R*	R*	R*	NR	NR	NR	NR
Inorganic zinc, post-cure ^e	NR	NR	NR	R*	NR	R*	R*	R*	R*	NR	NR	NR
Inorganic zinc, self-cure ^c ; water base ^c	NR	NR	NR	R*	NR	R*	R*	\mathbb{R}^*	R*	NR	NR	NR
Inorganic zinc, self-cure ^c ; solvent base ^c	NR	NR	NR	\mathbb{R}^*	NR	R*	R*	R*	R*	NR	NR	NR
Chlorinated rubber	R	R	R	NR	R	NR	R	NR	R	R	NR	NR
Notes: R, known compatibility; nor R*, known compatibility wit	mal practice th special su	e. Irface prepar	ation and/or at	policatio								

N, show comparently when special surface preparation and of appreation. NR, not recommended. This means it is not common practice to apply this topcoat over the specified primer, although certain products, if properly formulated, may be compatible. Certain combinations marked NR may be used, provided a suitable tie coat is applied between the two. X, not recommended because of insufficient data.

^b Vinyl wash primer required.
 ^c May be used as an after-blast primer.
 ^d Vinyl antifouling coating such as MIL-P-15931 may be applied.
 ^e May be used without topcoat.

Table 11 presents a summary of properties for organic zinc rich coatings and inorganic zinc (see Section 4.2.6.2(c) for further information on inorganic zinc coatings).

D	Organic zi	nc rich	Inorganic zinc		
Property	Chlorinated rubber base	Epoxy base	Water base	Solvent base	
Physical properties	Tough	Medium hard	Hard; metallic	Medium hard	
Water resistance	Very good	Very good	Excellent	Very good	
Acid resistance	Poor	Poor	Poor	Poor	
Alkali resistance	Fair	Fair	Fair	Fair	
Salt resistance	Good	Good	Very good	Very good	
Solvent resistance (hydrocarbons)					
Aromatic	Poor	Good	Excellent	Good	
Aliphatic	Very good	Very good	Excellent	Very good	
Oxygenated	Poor	Fair	Excellent	Good	
Temp. resistance	80°C	90°C	370°C	370°C	
Weather resistance	Very good	Good	Excellent	Excellent	
Age resistance	Good	Good	Excellent	Excellent	
Best characteristic	Fast dry	Good adhesion	Hard, abrasion resistant	Easier application	
Poorest characteristic	Solvent resistance	Application; weather resistance	Application	Poor cure; dry condition	
Principal use	Touch up; galvanize inorganic zinc	Touch up topcoated zinc systems Corrosion resistant base coat	Corrosion resistance, abrasion resistance	Corrosion resistant base coat	

TABLE 11. ZINC COATINGS, SUMMARY OF PROPERTIES [58]

4.2.6.2. Inorganic coatings

The term 'inorganic coating' may refer to a coating made from a number of classes of inorganic materials, among them ceramics, clays, glass, carbon, silicates and hydraulic cements that can set underwater. It may also be applied to inorganic coatings formed on a metal surface by chemical action (as opposed to metallic coatings applied to a metal's surface, which are discussed in Section 4.2.6.3) and may also be applied to zinc primers made with an inorganic solvent. Each of these is discussed in turn.

(a) Inorganic coating materials

(i) Cements

Hydraulic cement is a combination of cement and proprietary admixtures used for plugging and stopping water or fluid leaks in concrete and masonry. It is made up of hydraulic calcium silicates, generally containing calcium sulphate, and will set in 3–5 minutes. Hardened cement will retain its strength and hardness even if immersed in water. This makes it perfect for brick buildings in wet climates, harbour structures that are in contact with sea water and other applications.

Coatings made from ordinary mortar (from Portland cement) have nearly the same coefficient of thermal expansion as steel, are inexpensive and are easy to repair.

(ii) Inorganic ceramic coatings

Factory applied glass and other inorganic coatings such as enamels and ceramics can be applied to pipes and fittings at high temperatures for severe chemical exposure applications [59]. Application can be via furnace heating or flame or plasma spraying. Such coatings can be brittle and not tolerant of deformation or thermal shock and so are rarely used in waterworks applications.

(b) Inorganic metal coating treatments

Inorganic metal coating treatments change the immediate surface layer of metal into a film of metallic oxide or compound which has better corrosion resistance than the metal's natural oxide film and provides an effective base layer for supplementary protection such as paints [60]. The processes may or may not involve electrical assistance. Typical inorganic coating processes are listed in Table 12.

Process	Description	Comment
Anodizing	Electrolytic surface oxidation to add an aluminium oxide film that is integral to the metal substrate	Oxidized surface is hard and abrasion resistant, with some degree of corrosion protection
Chromate forming	Immersion in a strongly acid chromate solution to add a 5 μ m film	Suitable for application of sealing resins or paint
Phosphate coating	Proprietary treatments such as 'Parkerizing' or 'bonderizing' are available for use on steel. They are applied by brushing, spraying or prolonged immersion in acid orthophosphate solution containing iron, zinc or manganese.	Does not provide significant corrosion resistance when used alone, but provides an excellent base for oils, waxes or paints and helps prevent spreading of rust under layers of paint. Phosphating should not be applied to nitrided or finish- machined steel. Parts containing aluminium, magnesium or zinc are subject to pitting in the bath. Some restrictions apply to heat treated stainless and high strength steels.
Nitriding	Steels containing nitride forming elements such as chromium, molybdenum, aluminium and vanadium can be treated to produce hard surface layers providing improved wear resistance. Many of the processes are proprietary, but typically involve exposure of cleaned surfaces to anhydrous ammonia at elevated temperatures.	Nitrided steels usually exhibit improved fatigue and corrosion fatigue resistance
Passive films	Formation of naturally occurring transparent oxide films on austenitic and hardenable stainless steels	Films may be impaired by contaminants such as organic compounds, metallic or inorganic materials. Treatments can clean and degrease surfaces and produce uniform protective oxide films under controlled conditions. These usually involve immersion in aqueous solutions of nitric acid and dichromate.

TABLE 12. INORGANIC COATING PROCESSES

(c) Inorganic zinc primers

Inorganic zinc primers incorporate a high quantity of metallic zinc for pigmentation (hence the term 'zinc rich') and are either solvent or water based. Depending on the solvent and resins used, the coating may be a zinc rich epoxy or urethane. Inorganic zincs are specified for atmospheric and immersion service exposures. In mild environments, inorganic zinc paint may be used independently for corrosion protection of steel, but should be topcoated in more severe environments to extend service life. Table 11 in Section 4.2.6.1(c) presents properties for inorganic zinc coatings.

Inorganic zincs tend to have better corrosion resistance properties than organic zincs due to a better interconnected network of galvanic protection within the coating (Fig. 17).

4.2.6.3. Metallic coatings

Metallic coatings provide a new surface layer to the pipeline with surface properties essentially those of the applied metal. The pipe becomes a composite structure with a durable corrosion resistant outer layer and a load bearing inner layer. Metallic coatings may be considered when a pipeline may be subjected to abrasion, high temperatures or impact.

Use of such coatings requires that there is no galvanic incompatibility between coating and metallic substrate, especially in the presence of an electrolyte.

The most commonly used metallic coating method for corrosion protection is galvanizing. This involves the application of zinc onto CS. Hot-dip galvanizing is the most widespread method and consists of dipping the material to be protected into a bath of molten zinc. The relationship of galvanization thickness to service life is relatively well known for different conditions (Fig. 18). Galvanizing is generally effective within a pH range between 4.0 and 12.5 [61].



FIG. 17. Inorganic zinc (left) versus organic zinc epoxy (right).



FIG. 18. Service life of hot-dip galvanized coatings in various sample environments (courtesy of the American Galvanizers Association) [61].

Other coating methods involve electroplating (passing an electric current through a solution with dissolved metal ions that are attracted to the object being plated), electroless plating (deposition of nickel from an aqueous solution using chemical action only), cladding (metallurgically bonding a different metal to a surface via pressing, rolling or extrusion), or metallizing (thermal spray of a metal onto a heated metallic substrate). Thermal spray may be used on steel or reinforced concrete to provide CP for rebar. The most common spray-coating materials are listed in Table 13.

Coating type	General qualities
Aluminium	Highly resistant to heat, hot water and corrosive gases; excellent heat distribution and reflection
Babbitt	Excellent bearing wearability
Copper	High heat and electrical conductivity
Lead	Good corrosion protection, fast deposits and dense coatings
Molybdenum (Molybond)	Self-bonding for steel surface preparation
Monel	Excellent machining qualities; highly resistant to corrosion
Nickel	Good machine finishing; excellent corrosion protection
Nickel-chrome	High temperature applications
Chrome steel (Tufton)	Bright, hard finish; highly resistant to wear
Stainless steel	Excellent corrosion protection and superior wearability
Zinc	Superior corrosion resistance and bonding qualities

TABLE 13. THERMAL SPRAY COATING MATERIALS (ADAPTED FROM REF. [56])

4.2.6.4. Coating systems typically used for buried piping

(a) Enamels

Enamel coatings in various configurations have been used for pipeline protection for almost a century. They typically consist of an asphalt or coal tar base that is thickly applied to a pipe and covered with an outer wrap (Fig. 19). Early wraps were made of rag or asbestos felt, with resin-bonded glass fibre mats or other materials being used more recently. Neither asphalt nor coal tar traditionally could withstand continuous temperatures above 38°C, but recent formulations can withstand higher temperatures.

Enamel coatings do not inhibit CP current flow when they fail or become disbonded and have performed relatively well in service. They are, however, being replaced in general use by other coating systems such as fusion bonded epoxy or extruded polyolefin systems.

(b) Fusion bonded epoxy

Resistance to soil stress and cathodic disbondment has made fusion bonded epoxy (FBE) one of the most commonly specified pipe coatings [63]. FBE coatings are applied in a factory setting. Resin and hardener components that are unreactive at room temperature are heated (to approximately 245°C) and flowed onto a steel pipe's surface, where they solidify into a solid coating by chemical cross-linking, assisted by heat (Fig. 20). The chemical reaction is not reversible and further heating will not melt the coating.

FBE may be applied in a single layer (0.4 mm to 0.75 mm) or in a dual layer (0.5 mm to 1.1 mm) configuration. In a dual layer configuration the second layer of FBE is specifically modified with additional fillers to provide enhanced properties such as better gouge, abrasion or impact resistance. FBE can also be a component of multilayer polyolefin systems (see Section 4.2.6.4(f)).

Epoxies have inherently strong chemical resistance. Few chemicals can impact on such coatings, although some chemicals may influence rates of cathodic disbondment at defect sites. FBE is described as 'friendly' to CP. While the coating is an electrical insulator, its resistance is lower than for some high insulating coatings, enabling CP to still prevent corrosion at disbonded defect sites. FBE also has low oxygen permeability.

Sample standards include AWWA C213 [64] and CSA Z245.20 [65].



FIG. 19. Coal tar enamel protected pipe covered with ultraviolet protective kraft paper layer (courtesy of Northwest Pipe Co.) [62].

(c) Tape coating systems

Tape systems, which may be factory or field applied, consist of a primer, a corrosion-preventive inner layer of tape and one or two outer layers for mechanical and UV protection if needed [63]. Adhesives are used to bind the tape layers. Common tape materials include polyethylene (PE), polypropylene (PP) and PVC (Fig. 21).

Cold applied tapes are often used as a repair coating or to coat fittings (e.g. stubs or tees) following construction. Sample standards for steel pipelines are AWWA C214 [67] or C209 [68].

Petrolatum coating systems consist of a primer paste and wax-impregnated tape or blanket. They can be used when it is not possible to obtain a clean surface for adhesives to attach to and are mouldable to irregular or complex shaped piping, fittings and structures. A sample standard is AWWA C217 [69].



FIG. 20. Fusion bonded epoxy process schematic (courtesy of NACE International) [63].



FIG. 21. Polyolefin and polyethylene tape being factory applied (courtesy of Northwest Pipe Co.) [66].

(d) Polyolefin systems

Polyolefins are any polymers produced from a simple olefin (general formula C_nH_{2n}) as a monomer. Common polyolefins used in pipeline coating systems include PE and PP.

The first extruded polyolefin system was introduced in 1956 as a crosshead-extruded PE over an asphalt mastic adhesive. Today PP can be used at higher temperatures (up to 88°C). A process schematic is shown in Figs 22 and 23. The extruder heats, melts, mixes and extrudes the materials onto the steel pipe at the desired temperature and pressure. Polyolefins can also be fused to piping similar to FBEs.

The process consistently produces holiday free results. Multilayer polyolefin systems are described in Section 4.2.6.4(f).



FIG. 22. Side extruded polyolefin over side extruded butyl adhesive application schematic (courtesy of NACE International) [63].



FIG. 23. Side extruded pipe in factory: Polyolefin over butyl rubber adhesive (courtesy of Northwest Pipe Co.) [70].

Some sample standards related to polyolefin coatings are DIN 30670 [71] and AWWA C215 [72], C216 [73] and C225 [74].

(e) Liquid coating systems

Liquid coating systems are typically hand or spray applied (Fig. 24) onto piping. They are applied as custom coatings or in modified or repaired plant systems, usually on larger-diameter pipes or ductile iron pipes that may not be compatible with existing pipe coating factories [63]. They can provide abrasion resistance or protection of unprotected areas such as welds.

Common liquid coatings include liquid epoxies and polyurethanes. AWWA C210 [75] is a sample standard related to liquid epoxies, and AWWA C222 [76] and CSA Z245.22 [77] are sample standards specifically related to polyurethanes.

(f) Multilayer epoxy/extruded polyethylene or polyolefin systems

Multilayer epoxy/extruded polyolefin systems were first introduced in Europe in the mid-1960s. They are a hybrid system typically consisting of a hard layer of liquid epoxy or FBE, an adhesive and then a powdered or extruded PE or PP topcoat. Three-layer systems are often referred to as '3LPE' (for three-layer PE) or '3LPO' (for three-layer polyolefin) systems.

For onshore use, the standard top layer is an HDPE, while PP is used offshore or for higher operating temperature conditions. The FBE layer restricts oxygen passage and the PE or PP restricts water passage. HDPE provides the best combination of properties from the PE range, decreasing permeability to both water and oxygen and providing higher toughness (compared to lower density products). Repair, refurbishment or removal of such coating systems can be difficult.

Multilayer epoxy/polyolefin systems are the most-used pipe coating systems in Europe and are available throughout the world. Sample standards include DIN 30670 [71] and CSA Z245.21 [78].

(g) Heat shrinkable sleeves

Heat shrinkable sleeves (Fig. 25) are used in corrosion protection of pipeline girth welds. The sleeves are compatible with common pipe coatings, although somewhat different installation procedures may be required



FIG. 24. Polyurethane coating being factory applied (courtesy of Northwest Pipe Co.).



FIG. 25. Three-layer wrap around girth weld sleeve (courtesy of ShawCor Company, Canusa-CPS) [79].

depending on the main pipe coating employed. The sleeves adhere well to coal tar, coal tar enamel, asphalt based coatings, fusion bonded epoxies and common polymer pipe coatings — including PE and PP. Three-layer systems are available to provide comparable protection to 3LPO coatings.

A sample standard for such a sleeve for steel water lines is AWWA C216 [73].

4.2.7. Liner types

Liners help prevent internal corrosion and maintain a smooth internal pipe surface to maximize flow capacity. They can protect pipe interiors from fouling, abrasion and erosion and in some applications are used to prevent fluid contamination from pipe material.

Some commonly used linings for steel water pipelines include cement mortar, coal tar enamel, bitumen/ asphalt and epoxies made of coal tar, two component liquids and FBEs. Descriptions of types commonly in use are given in the following sections. Liners typically used for pipeline rehabilitation (e.g. cured-in-place pipe (CIPP) liners, slip liners, swage liners) are discussed in Section 8.2.1.3(e).

4.2.7.1. Cement mortar liners

Cement mortar lining is a commonly specified lining in the water transmission industry and for large diameter fire protection and circulating water piping systems in nuclear power plants. The mortar provides corrosion protection for the typical ductile iron pipe used, due to the high pH generated by the mortar's lime content at the iron surface.

The mortar typically contains three parts sand to one part cement and is centrifugally spun onto the interior surface to create a dense, smooth surface. Continued spinning (Fig. 26) removes excess water and compacts the mixture into a dense, hard surface. After spinning, the lining is cured either by moist curing at ambient temperature or by an accelerated process using steam. A sample application guideline is AWWA C205 [80]. Field application is also possible using a projection method (spinning head inside of pipe).

Cement mortar linings can develop drying cracks, but these cracks will self-heal when the lining is wet (although this ability degrades as the pipe ages). Wetting also causes the lining to swell, which increases strength and adherence.



FIG. 26. Pipe being lowered onto spinning belt for cement mortar lining application (courtesy of Northwest Pipe Co.) [81].

Soft, aggressive waters or prolonged contact with heavily chlorinated water may be injurious to cement mortar linings. Cement mortar linings perform best when flow velocity is 6 m/s or less.

4.2.7.2. Coal tar enamel liners

Coal tar enamel (CTE) is applied internally as a liner without reinforcement of shielding. The hot enamel is spun into the pipe to provide a smooth surface with low hydraulic resistance. A sample application guideline is AWWA C203 [82].

4.2.7.3. Bitumen/asphalt liners

Bitumen is used as a lining for steel and ductile iron pipelines. It may be applied as a thick, hot enamel or as a thin, cold applied (solvent diluted) system. Hot and cold materials can be applied by dipping, brushing, spraying or rolling. Thick, hot applied, bituminous linings are commonly used for raw water and sewage pipelines made of steel. Cold applied materials are mainly used for lining ductile iron pipes for carrying potable water. Care must be taken when using potable water systems as bitumen can support the growth of microorganisms.

The use of hot applied enamel for steel pipes and cold applied bitumen for ductile iron pipes is a matter of tradition and not of any special suitability of one over the other.

Thick, bituminous enamel linings protect steel pipelines provided the lining remains intact and is not damaged due to external influences such as ground settlement. Thin, cold applied painted or dipped linings for ductile iron pipes generally have a limited life expectancy, usually about five years. Today they are not regarded as satisfactory due to this short service life. Ductile iron potable water pipelines are more commonly lined with cement mortar (see Section 4.2.7.1) which affords better corrosion protection. In areas of high water alkalinity the cement mortar may be coated with a cold applied bitumen layer to shield the lining or to line the pipe with a solvent-free spray coating.

Some applicable standards are DIN 30673 [83], TS 4356 [84] and BS EN 10224 [85].

4.2.7.4. Epoxy and polyurethane based liners

Bonded dielectric linings such as epoxies and polyurethanes have been used as protective linings for above ground applications for many years. They are an excellent choice for extreme conditions such as wastewater or other industrial applications, including both gravity sewer and sanitary force mains.

The liners can be applied in various thicknesses, in either a single or multiple coating process. Surface preparation is critical. They are tough, resilient and extremely abrasion resistant, making them an ideal lining choice for high internal velocities.

Epoxy liners are typically solvent based, although some 100% solid epoxies are now available. They are typically mixed and then applied by airless spray or brushed on to the pipe. They typically cure in a matter of hours to days. Sample application guidelines are AWWA C210 for liquid epoxies [75], AWWA C213 for fusion bonded epoxies [64] and AWWA C203 for coal tar epoxies [82].

Polyurethane's applications and fabrication methods are similar to those of epoxies. Aromatic polyurethanes are typically 100% solid material and contain no volatile organic compounds. They do require heated, multicomponent equipment for their application; however, cure time is minimal (may be handled a few minutes following application). A sample application guideline is AWWA C222 [76].

4.2.7.5. Rubber liners

Rubber lined pipe fabricated from CS (RLCS) is used to transport abrasive slurry solutions, corrosive chemicals and many other liquids from one place to another. Common applications include flue gas desulphurization (thermal plants), seawater cooling and ore processing (mining).

4.2.8. Welding

The most common process applied in the construction or repair of nuclear power plant buried piping is joining of material members by welding. The completed process is examined to verify that the completed weldment is defect free. A detailed discussion of conventional and advanced welding technologies and ways to minimize welding is covered in IAEA Nuclear Energy Series No. NP-T-2.5 [86]. The American Petroleum Institute (API) has published a specific standard for pipeline welding and related inspection methods [87].

An important consideration during weld repairs of buried piping is to ensure any damage to coatings is addressed following welding. Areas of coating damage if left unrepaired can be future sites of degradation. Welded pipe repairs are discussed in Section 8.2.1.3 (d).

4.2.9. Fittings, valves, hydrants, joints and penetration seals

Complete buried and underground piping and tank systems are designed and assembled using a variety of miscellaneous components. These include fittings, valves (e.g. gate valves, butterfly valves, plug valves, check valves, air release valves (ARVs), fire hydrants, joint components (e.g. flanges, tees and gaskets), water meters, penetration seals and others. Fitting, valve and joint materials are generally similar to those of the pipe itself; however, special care should be taken to ensure that any changes in material do not adversely impact on CP systems.

ARVs are used to help resolve air entrapment issues. ARVs are typically located at high point elevations in force mains. They release any entrapped air caught at system high points. If this air is left in systems it can reduce efficiency, cause water hammering, or in extreme cases cause a total system 'air lock'.

Penetration seals are installed at buried pipe or conduit entries into buildings and other underground structures and play a key role in ensuring critical plant areas remain dry following changes in water table levels, flooding and extreme weather events. They may also provide an insulating barrier to pipe casings (see Section 4.2.4.3). Above ground or in tunnels they may also provide a fire barrier sealing function. Seals are generally made of flexible elastomeric materials depending on the application.

4.3. AGEING MECHANISMS

4.3.1. Background

Ageing degradation mechanisms, such as corrosion, can lead to failures in plant infrastructure which are usually costly to repair, costly in terms of environmental damage and possibly costly in terms of human or environmental safety.

Understanding ageing mechanism fundamentals is necessary for preventing these mechanisms from degrading by using appropriate protection means. It is also necessary for predicting buried pipe behaviour in service conditions.

Degradation of buried piping may occur with any kind of pipe material (metal, concrete, polymer, etc.) from the inside and/or from the outside. Its origin may be linked to poor design, construction or maintenance, or the internal or external environment of the buried pipe.

In this section ageing mechanisms that may occur in buried piping will be described.

4.3.2. Degradation mechanisms and materials

Depending on its components, a buried pipe may be sensitive to such degradation mechanisms as:

- Corrosion;
- Droplet impingement;
- Fatigue;
- Tuberculation or occlusion;
- Freeze–thaw cycling;
- Settlement and soil displacements;
- Wear.

Polymers and concrete pipes and other structures can be subject to degradation mechanisms specific to their material nature. These include SCG and UV radiation for polymers, and chemical attacks and corrosion of internal metallic components for concrete.

Table 14 presents which of these mechanisms are applicable to metals, concrete and polymer materials. Table 15 describes specific mechanisms associated with buried piping and tank materials, including metallic and non-metallic materials, materials used for concrete pipe and coatings.

Degradation mechanism	Metals	Concrete	Polymers
Corrosion	Х		
Cavitation corrosion	Х	Х	
Droplet impingement	Х		
Fatigue	Х	Х	
Freeze-thaw cycling		Х	
Settlement and soil displacements	Х	Х	Х
SCG			Х
Wear	Х		

TABLE 14. SENSITIVITY OF MATERIALS TO DEGRADATION MECHANISMS

Text cont. on p. 67.

	Consequences of ageing	Possible loss of flow capacity/ system functionality	Possible loss of flow capacity/ system functionality
	Condition monitoring and mitigation	Monitoring: • Visual inspection • Direct and indirect non-destructive testing (NDT) methods Mitigation: • Use thicker materials • Coatings • Corrosion inhibitors • CP	Monitoring: • Visual inspection • Direct and indirect NDT methods Mitigation: • Avoid creating stagnant conditions • Control pH, chloride concentration and temperature • CP • Use higher alloys for increased resistance to corrosion
piping and components	Potential critical parts/ locations	All internal or external pipe surfaces directly in contact with fluids or moisture (unless protected or corrosion resistant)	Pipes containing aggressive ions (e.g. sea water, high chloride conc.)
Part A: Metallic	Ageing effect	Leak or break	Leak (or break if not addressed) Can also act as stress risers Fatigue and stress corrosion cracking may initiate at base of corrosion pits
	Degradation mechanisms	Uniform corrosion	Pitting corrosion
	Ageing stressors/environment	Dissolved O ₂ , pH < 4, flow and temperature are influencers	Localized chemical or mechanical damage to oxide films Poor coating application Metal non-uniformities (inclusions)

	Consequences of ageing	Possible loss of flow capacity/ system functionality
	Condition monitoring and mitigation	 Monitoring: Visual inspection Direct and indirect NDT methods Mitigation: Avoid creating stagnant conditions Use welded butt joints instead of riveted or bolted joints Eliminate crevices in lap joints by continuous welding or soldering Use solid, non-absorbent gaskets Use higher alloys for increased resistance to corrosion CP
c piping and components	Potential critical parts/ locations	Geometric discontinuities (gaps, joints, gaskets, seals, etc.) in stagnant conditions or under deposits
Part A: Metalli	Ageing effect	Leak (or break if not addressed)
	Degradation mechanisms	Crevice corrosion
	Ageing stressors/environment	Stagnant microenvironments

	d Consequences of ageing	Possible loss of flow capacity/ system functionality let er	Possible loss of flow capacity/ system functionality out
	Condition monitoring an mitigation	 Monitoring: Visual inspection Direct and indirect NDT methods Mitigation: Select materials as close together as possible in tl galvanic series Insulate dissimilar meta from each other wherew practical Apply coatings (with caution) Avoid threaded joints for materials far apart in the galvanic series CP 	 Monitoring: Visual inspection Direct and indirect NDT methods Mitigation: Remove stray current source or reduce its outper current Electrical bonding Cathodic shielding Install sacrificial anodes Apply coatings to current pick-up areas
allic piping and components	Potential critical parts/ locations	n.a.	Areas near DC or AC lines, substations or street transit systems Areas where CP is applied Areas near welding machine use
Part A: Met	Ageing effect	Leak (or break if not addressed)	Leak (or break if not addressed)
	Degradation mechanisms	Galvanic corrosion	Stray current corrosion
	Ageing stressors/environment	Galvanic couple formation	Stray currents from DC or AC power line or other sources

	Consequences of ageing	Possible loss of flow capacity/ system functionality Failures can be high energy/ dangerous to personnel	Possible loss of flow capacity/ system functionality	Possible loss of flow capacity/ system functionality
	Condition monitoring and mitigation	Monitoring: • FAC predictive software • NDT Mitigation: • Control fluid velocity • Use more FAC resistant materials (notably increasing chromium content) • Use corrosion inhibitors or CP to minimize erosion corrosion	Monitoring: n.a. Mitigation: • Reduce flow rates • Increase system pressure • Design piping systems to limit unnecessary valve throttling	Monitoring: • Visual inspection • Direct and indirect NDT methods Mitigation: • Lubricating surfaces • Inspecting and maintaining lubrication
viping and components	Potential critical parts/ locations	Carbon or low alloy steel piping exposed to flowing water or wet steam Most severe cases of FAC degradation are observed in a temperature range from 100°C to 220°C	Pump suctions Valves Regulators Pipe elbows; reducers, expansions	Vibrating/moving components Piping subject to waterhammer Flexible couplings
Part A: Metallic _I	Ageing effect	Leak or break if not addressed	Pitting on surfaces and erosion/corrosion	Corrosion damage at contact surfaces
	Degradation mechanisms	FAC	Cavitation	Fretting (not a usual degradation mechanism for buried piping)
	Ageing stressors/environment	Corrosion in a stream of flowing water or wet steam	Collapse of vapour bubbles on surfaces as fluid pressure falls below vapour pressure	Loading in presence of relative surface motion

nent	Degradation mechanisms	Part A: Metallic _F Ageing effect	oiping and components Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
Stress corros cracking		Crack formation leading to unexpected sudden failure	More common in alloys than pure metal (e.g. alloy 600) Has been observed in steam generators, pressure vessel components, welds Can be enhanced by radiation	Monitoring: n.a. Mitigation: • Avoid chemical species causing stress corrosion cracking (SCC) in environment • Control hardness and stress levels (residual or load) • Use materials known not to crack in specified environment • Control operating temperatures and/or alloy electrochemical potential	Possible loss of flow capacity/ system functionality
Corrosion fat	igue	Fatigue impacts enhanced when compared to same metal in air	п.а.	Monitoring: n.a. Mitigation: n.a.	Possible loss of flow capacity/ system functionality
Hydrogen embrittlement		Embrittlement and cracking due to uptake of H_2 into materials	п.а.		Possible loss of flow capacity/ system functionality
Scaling		Loss of interior pipe diameter/ blockage	п.а.	Monitoring: n.a. Mitigation: • Control pH • Add scale inhibitors • Remove scaling species	Possible loss of flow capacity/ system functionality
Biofouling		Loss of interior pipe diameter/ blockage	Cooling water systems, esp. open recirculation systems	Monitoring: n.a. Mitigation: • Treatment with biocides so as to control bacteria population	Possible loss of flow capacity/ system functionality

Contromment Designation indications glocally Ageing effect rotations locations areas, usually priting Controme and position Controme areas, usually priting glocally MC Can cause localized corresion areas, usually priting CS, Cu alloys, stainless steel, areas, usually priting Monitoring: Possibility Possibility glocally MC Can cause localized corresion areas, usually priting CS, Cu alloys, stainless steel, areas, usually priting Monitoring: Possibility		Downdrition	Part A: Metallic p	iping and components	Condition monitoring and	
MIC Can cause localized corrosion attack, usually pitring Can cause localized corrosion attack, usually pitring Can cause localized corrosion on pipe, fund carried and soil to determine organisms Possibility stemmine A lalloys A lalloys • Can alloys, stainless steel, on pipe, fund carried and soil to determine organisms system A lalloys A lalloys • Can alloys, stainless steel, on pipe, fund carried and soil to determine organisms system A lalloys • Can alloys, stainless steel, novel • Can allo determine organisms system A lalloys • Can alloys, stainless steel, novel • Can allo determine organisms system A lalloys • Can alloys • Can alloys • Can allo determine organisms system A lalloys • Can allo determine organisms • Can allo determine organisms system A lalloys • Can allo determine organisms • Can allo determine organisms system A landopet Ensoin danage and metal Pumps, valves, orifices, allo argue organisms Possible A langue due to Fanouro Monitoring: n.a. Possible A langue due to external Langue ortedue due active Possible A lang	nent	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
tails at impingement Liquid droplet Erosion damage and metal elbows, tees Monitoring: n.a. Possibility astem impingement removal elbows, tees Mitigation: estence flow rate estence flow rate impingement removal elbows, tees Mitigation: estence flow rate estence flow so as to prevent alor Fatigue due to external Leakage or breakage Piping routed under railways, Monitoring: mail Possibility alor Fatigue due to external Leakage or breakage Piping routed under railways, Monitoring: mail Possibility cyclic loads ecc. Monitoring: etc. Monitoring: etc. Monitoring Possibility ecclic loads etc. Monitoring: etc. Of daping operating conditions to reduce cyclic loads Possibility ecolic loads etc. Monitoring: etc. Monitoring etc. Possibility ecolic loads etc. Monitoring: etc. Monitoring etc. etc. ecolic loads etc. Monitoring: etc. Monitoring etc. etc. etc. etc. etc. etc. <td< td=""><td></td><td>MIC</td><td>Can cause localized corrosion attack, usually pitting</td><td>CSs, Cu alloys, stainless steel, Al alloys</td><td> Monitoring: Sampling of films or slimes on pipe, fluid carried and soil to determine organisms involved Mitigation: Periodic mechanical cleaning Treatment with biocides so as to control bacteria population and detach any films Complete drainage and dry storage </td><td>Possible loss of flow capacity/ system functionality</td></td<>		MIC	Can cause localized corrosion attack, usually pitting	CSs, Cu alloys, stainless steel, Al alloys	 Monitoring: Sampling of films or slimes on pipe, fluid carried and soil to determine organisms involved Mitigation: Periodic mechanical cleaning Treatment with biocides so as to control bacteria population and detach any films Complete drainage and dry storage 	Possible loss of flow capacity/ system functionality
al or Fatigue due to external Leakage or breakage Piping routed under railways, Monitoring: Possible cyclic loads ctc. roads, etc. Mitigation: • Traffic monitoring system Mitigation: • Adapting operating conditions to reduce cyclic loadings • Designing equipment to reduce or accommodate cyclic loadings	cetals at	Liquid droplet impingement	Erosion damage and metal removal	Pumps, valves, orifices, elbows, tees	 Monitoring: n.a. Mitigation: Reduce flow rate Filter flow so as to prevent entrained solids Design piping systems to avoid large pressure drops 	Possible loss of flow capacity/ system functionality
	al or	Fatigue due to external cyclic loads	Leakage or breakage	Piping routed under railways, roads, etc.	 Monitoring: Traffic monitoring Mitigation: Adapting operating conditions to reduce cyclic loadings Designing equipment to reduce or accommodate cyclic loadings 	Possible loss of flow capacity/ system functionality

	Degradation	Part A: Metallic J	piping and components Potential critical parts/	Condition monitoring and	enione de contractione de
dup of debris, macrofouling	mechanisms Tuberculation/	Flow blockage	locations More common in smaller	mitigation Monitoring:	Possible loss of flow capacity/
orrosion products	occlusion		pipes and in dead legs	 visual inspections Flow measurements Mitigation: Chemical treatment 	system functionality
erosion; changes in ironmental conditions (e.g. ındwater levels), earthquakes	Settlement and soil displacement	Pipe deformation or failure	n.a.	 Monitoring: Visual inspections/ walkdowns Groundwater monitoring Structure displacement monitoring Mitigation: Limit soil erosion as much as possible Improve drainage systems when possible 	n.a.
ative movement between tacting surfaces	Wear	Pipe thinning causing leaks or breakage	n.a.	 Monitoring: n.a. Mitigation: Apply lubricant to contacting surfaces Reduce load at contact surfaces Reduce as much as possible relative motion between contact surfaces Use wear resistant materials 	n.a.

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	Consequences of ageing	ц.	n.a.	n.a.
	Condition monitoring and mitigation	 Monitoring: Visual inspection For flexible non-metallic components, physical manipulation to detect loss of strength (i.e. hardness testing) Mitigation: Follow manufacturer's recommendations followed during installation, inspection and repair (may require pipe covering) Protect by a coating, or through use of a UV stabilizer 	Monitoring: • Visual inspection • Inspect for sharp edge defects on external surface Mitigation: n.a.	 Monitoring: Visual inspection Quality control testing of joints during fabrication In-service leak monitoring Mitigation: Follow proper installation procedures and employ good quality assurance
ic piping and components	Potential critical parts/ locations	Not normally applicable to buried piping when manufacturer's recommendations followed during installation, inspection and repair (i.e. when exposed)	Primary failure mode for HDPE pipe	HDPE joints
Part B: Non-metall	Ageing effect	Loss of material strength (if exposed)		Brittle joint failure of HDPE joints
	Degradation mechanisms	UV radiation, ozone, ionizing radiation	SCG	Improper fusion
	Ageing stressors/environment	UV radiation, ozone, ionizing radiation		Improper installation/fabrication

		Part B: Non-metalli	c piping and components		
Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
High tensile forces	Mechanical damage	Material shearing, separation or fracture	FRP materials	Monitoring: • Visual inspection Mitigation: • Proper design and installation	п.а.
Chemical attack	n.a.	n.a.	Fibreglass exposed to chlorine	Monitoring: • Visual inspection Mitigation: • Control exposure via operational or design changes	n.a.
Temperature	п.а.	Cracking or change in material properties	Elastomers, HDPE	Monitoring: • Visual inspection Mitigation: • Control exposure via operational or design changes	n.a.
Cyclic loading (mechanical or thermal)	Fatigue	Leakage or breakage	Piping routed under railways, roads, etc.	Monitoring: n.a.Mitigation:Adapting operating conditions to reduce cyclic loadingsDesigning equipment to reduce cyclic loadings	n.a.

	Consequences of ageing	n.a.		Consequences of ageing	Progressive disintegration, reduction in load carrying capacity
	Condition monitoring and mitigation	 Monitoring: Visual inspections/ walkdowns Groundwater monitoring Structure displacement monitoring Mitigation: Limit soil erosion as much as possible Improve drainage systems when possible 		Condition monitoring and mitigation	 Monitoring: Visual inspection, testing of concrete samples Mitigation: Minimizing access to the water through use of low permeability concretes, sealers and barriers
lic piping and components	Potential critical parts/ locations	n.a.	ncrete pipe material	Potential critical parts/locations	External surfaces subject to salt spray; structures in contact with fluctuating water (e.g. water intake structures), areas where road salt is applied
Part B: Non-metall	Ageing effect	Pipe deformation or failure	Part C: Con	Ageing effect	Cracking
	Degradation mechanisms	Settlement and soil displacement		Degradation mechanisms	Salt crystallization
	Ageing stressors/environment	Soil erosion; changes in environmental conditions (e.g. groundwater levels), carthquakes		Ageing stressors/environment	Exposure to water containing dissolved salts (e.g. sea water, road salt)

		Part C: Conc	srete pipe material		
Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
Exposure to thermal cycles at relatively low temperatures and high humidity	Freeze-thaw	Cracking; spalling	External surfaces where geometry supports moisture accumulation	 Monitoring: Visual inspection, testing of concrete samples mitigation: Minimize concrete exposure to moisture by repairing cracks and waterproofing concrete surface For new concrete: air entrainment used to minimize potential occurrence 	Disintegration of concrete, reduction in load carrying capacity
Thermal exposure/thermal cycling	Moisture content changes and material incompatibility due to different thermal expansion values	Cracking; spalling; strength loss; reduced modulus of elasticity	Generally, an issue for hot spot locations; near hot process and steam piping	 Monitoring: Visual inspection, periodic measurements of concrete surface temperatures Mitigation: Control temperature of exposure, where possible, providing insulation to concrete surface 	Reduction of mechanical properties and load carrying capacity; can increase concrete creep that can increase prestressing force losses
Exposure to flowing gas or liquid carrying particulates and abrasive components	Abrasion; erosion; cavitation	Continued loss of material and exposure of aggregate	Cooling water intake and discharge structures	 Monitoring: Visual inspection Mitigation: Eliminate source and improve quality of concrete surface Protect vulnerable corners with metal shapes Apply protective coatings 	Reduced load carrying capacity of concrete Increased resistance to flow in fluid systems

	Consequences of ageing	Typically localized damage, excessive deflection, brittle fracture	Excessive deflections, differential movement, misalignment of components and equipment	Reduced load carrying capacity of the concrete over long term leaching Corrosion of steel reinforcement
	Condition monitoring and mitigation	 Monitoring: Visual inspection, monitoring of the loading, analysis Mitigation: Should be taken into account during design stage design changes to accommodate cyclic loadings and vibration 	 Monitoring: Visual inspection, periodic settlement monitoring Mittigation: Should be taken into account during design stage design changes, such as strengthening 	 Monitoring: Visual inspection, periodic analysis of the fluid, testing of concrete samples Mitigation: Minimize percolation of fluid by diversion, if possible Use protective liners/ coatings, especially at joints
crete pipe material	Potential critical parts/ locations	Equipment/piping supports	Connected structures or independent foundations	Structures exposed to water (e.g. subgrade structures, water intake, spent fuel bays) Near cracks, areas of high moisture percolation
Part C: Con	Ageing effect	Cracking; strength loss	Cracking	Increased porosity and permeability; lowers strength May indicate changes to cement paste, makes concrete more vulnerable to hostile environments
	Degradation mechanisms	Fatigue	Settlement	Efflorescence and leaching
	Ageing stressors/environment	Cyclic loads/vibrations	Consolidation or movement of soil on which structure is founded	Percolation of fluid through concrete due to moisture gradient

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	Consequences of ageing	Progressive loss of strength and mass Reduced load carrying capability	Reduced load carrying capability
	Condition monitoring and mitigation	 Monitoring: Visual inspection, periodic analysis of water and soil chemistry, testing of concrete samples Mitigation: Minimize access of sulphates to the structure by diversion of the groundwater, if possible (e.g. improving drainage), waterproofing concrete For new concrete: sulphate resistant cements or partial replacement of cements with supplementary cementing materials can be used to minimize potential occurrence 	 Monitoring: Visual inspection, periodic analysis of water chemistry, testing of concrete samples Mitigation: Minimize access of acids and bases to the structure by improving protection of the concrete (repair cracks, improve waterproofing) Use siliceous aggregates in concrete which are more resistant to acid
oncrete pipe material	Potential critical parts/ locations	Subgrade material	Local areas subject to chemical spills; pipework carrying aggressive fluids
Part C: Co	Ageing effect	Expansion and irregular cracking	Increased porosity and permeability
	Degradation mechanisms	Sulphate attack	Conversion of hardened cement to soluble material that can be leached
	Ageing stressors/environment	Exposure to alkali and magnesium sulphates present in soils, sea water or groundwater	Exposure to aggressive acids and bases

		Part C: Conc	srete pipe material		
Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
Combination of reactive aggregate, high moisture levels and alkalis	Alkali-aggregate reactions	Cracking which may eventually lead to complete destruction of the concrete mass; gel exudation; aggregate popout	Areas where moisture levels are high and improper (reactive) materials utilized	 Monitoring: Visual inspection, periodic analysis of concrete humidity and testing of concrete samples Mitigation: Minimize concrete exposure to moisture by repairing cracks and waterproofing concrete surface For new concrete: eliminate potentially reactive materials; use low-alkali content cement replacement 	Reduced load carrying capacity
Aggressive marine water	Deterioration from combined effects of chemical action of seawater constituents on cement hydration products, alkali- aggregate reactions (AARs), crystallization pressure of salts within concrete, frost action in cold climates, corrosion of embedded rebar and physical erosion	Cracking, corrosion, etc.	Concrete exposed to marine environments	Monitoring: • Visual inspection • Concrete testing • Continuity testing/electrical testing of reinforcement Mitigation: • Visual inspection • Concrete testing	n.a.

		Part C: Conc	crete pipe material		
Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
Biological attack	Growth on structures from mechanical deterioration from bursting forces Microorganism excretion of acids corroding surfaces (MIC)	Mechanical damage and corrosion (loss of concrete mass)	Sewers	Monitoring: • Visual inspection • Concrete testing Mitigation: • Chemical addition • Coatings	n.a.
Irradiation	Aggregate expansion; hydrolysis	Cracking; loss of mechanical properties	Structures proximate to reactor vessel	 Monitoring: Periodic measurement of level of radiation, testing of concrete samples Mitigation: Control levels of radiation, where possible, providing insulation and shielding 	Prolonged exposure may cause reduction of mechanical properties and load carrying capacity Typically, containment irradiation levels are below threshold levels to cause degradation
Depassivation of steel due to carbonation or presence of chloride ions	Composition or concentration cells leading to pitting, general or microcell corrosion	Concrete cracking and spalling, loss of reinforcement cross-section	Outer layer of steel rebar in all structures where joints, cracks or local defects are present	 Monitoring: Visual inspection Testing of concrete samples Monitoring (e.g. half-cell potential, resistivity and polarization resistance) Mitigation: Apply protective coatings Improve quality of concrete cover CP 	Prominent potential form of degradation; leads to reduction in load carrying capacity and serviceability

		Part D: C	oating materials		
Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
Mechanical action of rubbing, scraping, scratching, gouging or erosion (heavy rains, high winds, sand, slurries or installation/ repair damage)	Abrasion and mechanical damage	Coating wears down to bare surface	Exposed pipework of pipe carrying abrasive slurries Often seen in brushed exterior organic coatings Following installation or repair activities	 Monitoring: Visual inspection Mitigation: Abrasion resistant coatings can be used during installation or repair where abrasion is likely Full pipe exterior inspection and repair as required prior to backfilling 	Metal failure due to corrosion as substrate attacked
General ageing/weathering	Adhesion related failur	cs			
	Peeling	Small coating pieces detach from surface; edges are normally raised up and can be easily removed	Soft and pliable fresh coatings (e.g. vinyls)	 Monitoring: Visual inspection Mitigation: Proper coating selection, surface preparation and personnel qualification 	Metal failure due to corrosion as substrate attacked
	Flaking	Small coating flakes detach from coating surface	Galvanized surfaces with aged alkyd or oil based paint	 Monitoring: Visual inspection Mitigation: Proper coating selection, surface preparation and personnel qualification 	Metal failure due to corrosion as substrate attacked
	Scaling	Similar to flaking with larger pieces (10 cm) detaching	Coated galvanized surfaces Where new coats are applied over old coats with poor surface preparation	Monitoring: • Visual inspection Mitigation: • Proper coating selection, surface preparation and personnel qualification	Metal failure due to corrosion as substrate attacked
		Part D: C	oating materials		
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Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
Application related	Alligatoring	Very large (macro) crazing/ cracking in coating	Some air dried or chemically cured organic coatings when applied over a cold surface Asphalt and coal tar coatings Thickly applied coatings	 Monitoring: Visual inspection Mitigation: Proper coating selection, surface preparation and personnel qualification 	Coating flaking from surface, reducing coating cross-section, bare metal exposure (for corrosion) and eventual failure
Damp/humid conditions	Biological/ microorganism attack	Coating turns grey or green with black splotchy areas	Organic oil type coatings, alkyds, polyamide epoxies and those using biodegradable plasticizers	 Monitoring: Visual inspection. Mitigation: Attacks can be reduced in oil coatings by adding zinc oxide, fungicides, bactericides or all three into coating formulation 	
Excessive amounts of CP current	Blistering	Dome shaped projections or blisters appear on coating	Coated pipelines in wet soil with cathodic potentials in excess of 1.0 V	Monitoring: • Visual inspection Mitigation: • Reduce CP current	Metal failure due to corrosion as substrate attacked
Osmotic gradients associated with soluble salts, soluble pigments and corrosion products			Coatings immersed in water, sea water or other liquids	 Select low solubility Select low solubility coatings to minimize through coating osmosis Promer coating selection 	
Rapid-dry coatings applied in sun			Rapid-dry coatings applied in sun	application and pipe	
Fabrication issues allowing gases from metal to escape into coating			Improper pickling processes Cast iron is susceptible		

		Part D: C	oating materials		
Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
Sunlight action (on organic binder)	Chalking	Chalk or powder appearance on coating surface. Generally, a slow surface process	Organic coatings Characteristic of certain paints such as epoxy paints	 Monitoring: Visual inspection Mitigation: Apply suitable topcoat with high UV resistance and resistance to chalking 	Normally not consequential. Clean chalked surfaces free of corrosion can be satisfactorily repainted
Wetting/drying, heating/cooling or sunlight exposure	Checking	Surface breaks in coating that do not penetrate to surface	Organic coatings Inorganic zincs	 Monitoring: Visual inspection Mitigation: Proper coating selection, surface preparation and personnel qualification 	Coating may degrade further if not addressed Less of a problem for inorganic zincs than for organic coatings, as fine checks can fill with zinc reaction products
Chemical exposure to volatile acids (e.g. acetic, hydrochloric, nitric)	Chemical attack		Coatings exposed to volatile acids (e.g. acetic, hydrochloric, nitric)	 Monitoring: Visual inspection Mitigation: Proper coating selection, surface preparation and personnel qualification 	
Chemical attack (acid or alkali)	Corrosion	Rapid coating failure by chemical attack Coating dissolution Under-film/undercutting corrosion	Zinc coatings (organic or inorganic, galvanized coatings) without proper topcoat Chemical storage tanks	 Monitoring: Visual inspection Mitigation: Proper coating selection and surface preparation Apply resistant topcoats 	Rapid coating failure

		Part D: Cc	oating materials		
Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
Ageing and weathering	Corrosion: pinpoint rusting	Corrosion starting in small pinpoint areas	Zinc coatings (organic or inorganic, galvanized coatings) applied with improper thickness or near end of useful life	Monitoring: • Visual inspection Mitigation: • Apply resistant topcoats Apply maintenance coat at first sign of pinpoint failure	Metal failure as areas of corrosion expand and combine
Application related	Corrosion: undercutting	Progressive corrosion under coating from breaks, pinholes, holidays or unprotected edge	Coatings applied over contaminated or very smooth surfaces	 Monitoring: Visual inspection Mitigation: Proper coating selection, surface preparation and application Use organic zinc coating primer 	Metal failure due to corrosion as substrate attacked
Ageing and weathering	Cracking	Rapid corrosion at coating breaks that penetrate to surface	Organic coatings made from oxidizing materials (oils, alkyd resins) or internal curing resins (e.g. epoxies)	 Monitoring: Visual inspection Low voltage (wet sponge) holiday testing Mitigation: Proper coating selection, surface preparation and personnel qualification 	
Improper coating selection, surface preparation (between layers) or application	Delamination	Topcoat not adherent to undercoat (may lie on surface, blister or peel)	Air reactive coatings needing oxygen or moisture to cure; coatings with internally reactive catalysts or resins Incompatible coating layers Coal tar epoxies are susceptible	 Monitoring: Visual inspection Adhesion testing Mitigation: Proper coating selection, surface preparation and application 	Exposure of undercoat Eventual metal failure due to corrosion if undercoat attacked and fails

	Consequences of ageing	Typically not a functional issue for piping or tanks	Typically not a functional issue for piping or tanks	Metal failure
	Condition monitoring and mitigation	Monitoring: • Visual inspection Mitigation: • Proper coating selection if colour properties important	Monitoring: • Visual inspection; treat surface with dilute hydrochloric acid; disappearance of blackening indicates sulphide presence (and distinguishes it from mould growth) Mitigation: • Proper coating selection if colour properties important • Repaint using paints that do not contain mercury, lead driers; remove any lead/mercuts undercoats	 Monitoring: Visual inspection Low voltage (wet sponge) holiday testing Mitigation: Proper coating selection, surface preparation and personnel qualification
oating materials	Potential critical parts/ locations	Organic coatings containing unsaturated photosensitive groups	Organic paints containing lead, mercury or copper. Exposure to contaminated water	Zinc coatings (inorganic, galvanized coatings) immersed in sea water
Part D:	Ageing effect	Darkening, yellowing, browning, blackening or other discolouration in sunlight	Colour turns grey or black in patches or streaks	Pits occur (possibly after 12 to 24 months of seawater exposure), typically starting at sharp edges, abrasions or holidays
	Degradation mechanisms	Discolouration	Discolouration	Seawater pitting
	Ageing stressors/environment	Exposure to sunlight/weathering	H ₂ sulphide attack	Seawater exposure

		Part D: Cc	oating materials		
Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
	Wrinkling	Formation of furrows or ridges on a coating surface	Most common with oil based paints or alkyds with driers added to the formulation to increase drying rates Excessive thickness can aggravate the condition	 Monitoring: Visual inspection Mitigation: Proper coating selection, surface preparation and personnel qualification 	
Improper surface preparation (not ageing related; however, effects can become evident during startup or after many years in service)	Blistering, rust, tubercles on steel previously exposed to corrosion	Dome-like blisters, corrosion, or tubercles (round nodules) appear on coating	Previously used or exposed steel not properly prepared for recoating	Monitoring: • Visual inspection • Holiday testing Mitigation: • Proper surface preparation/ anticorrosive primer	Exposure of substrate/possible failure
	Zinc corrosion products forming under coating and breaking through	Zinc salts forming under coating break through surface	Galvanized or metallic zinc surfaces	Monitoring: • Visual inspection • Holiday testing Mitigation: • Proper surface preparation/ anticorrosive primer	Exposure of substrate/possible failure
	White corrosion products causing pinpoint failures or blistering	Corrosion starting in small pinpoint areas, or dome-like blisters forming	Aluminium pipe/conduit	Monitoring: • Visual inspection • Holiday testing Mitigation: • Proper surface preparation/ anticorrosive primer	Metal failure
	Grey-green corrosion products	Corrosion of metal	Coated copper surfaces	Monitoring: • Visual inspection • Holiday testing Mitigation: • Proper surface preparation/ anticorrosive primer	Metal failure

		Part D: Co	oating materials		
Ageing stressors/environment	Degradation mechanisms	Ageing effect	Potential critical parts/ locations	Condition monitoring and mitigation	Consequences of ageing
	Coating blistering or peeling on concrete	Dome-like blisters forming or peeling of coating	Coated concrete surfaces	 Monitoring: Visual inspection Holiday testing Mitigation: Proper surface preparation Highly penetrating primer with strong alkali resistance 	Metal failure
Application/fabrication failures (not ageing related; however, effects can become evident during startup or after many years in service)	Uneven/improper application (coating holidays, pinholes, overspray, splatters, craters, bleeding, lifting, orange peeling, runs)	Dependent on extent of unevenness	Manually applied coatings Areas/structures difficult to coat (edges, deep square corners, areas needing rivets, boltheads, threads, welds, skip welds (overlapping plates) in tank roofs, tank crevices, fittings, etc.) Porous surfaces (porous zinc substrates, concrete, etc.)	 Monitoring: Visual inspection Holiday testing Mitigation: Proper coating selection, application and inspection Pay special attention to difficult to coat areas (brush coats, extra coats, etc.) Use immediate mechanical force to fill pinholes during application (e.g. brush with several passes) 	Possible coating failure depending on degree
Improper coating formulation (not ageing related; however, effects can become evident during startup or after many years in service)	Improper coating formulation	Poor adhesion, improper thickness, checking, cracking, flaking, pinholes, colour changes	Site mixed or thinned coating systems	 Monitoring: Visual inspection Adhesion testing (during installation) Holiday testing Mitigation: Proper coating selection, mixing and thinning 	Possible coating failure depending on degree

Conduit hydrostatic seals for buried and underground piping can have an important role in physical protection features related to external flood protection. Inspections at nuclear facilities since the accident at the Fukushima Daiichi nuclear power plant have uncovered instances of missing, improperly specified, improperly installed or degraded seals [88, 89].

4.3.3. Corrosion

Most buried piping transports water. Degradation of such piping is primarily due to corrosion and may occur from both the inside and the outside of the pipe. Other buried pipelines (e.g. diesel fuel, instrument air) may suffer degradation from outside corrosion.

Corrosion is undesirable metal deterioration by a chemical or electrochemical reaction with its environment. In water systems, corrosion may result in the failure of components and piping, or loss of efficiency from deposition of corrosion products. Corrosion occurs at the anode where the base metal dissolves while reduction takes place at the cathode. General corrosion results when anode and cathode sites shift from place to place. In this case, fouling from corrosion products is the more likely problem.

Localized corrosion occurs when the anodic site remains stationary and can lead to equipment failure. Examples of localized corrosion include pitting, crevice corrosion, galvanic corrosion, dealloying, under-deposit corrosion, stress corrosion cracking and microbiologically influenced corrosion (MIC). Corrosion in water systems is affected by many factors, including:

- pH very low or high pH;
- Temperature higher temperatures usually cause higher corrosion rates;
- Dissolved solids or dissolved gases higher levels of chlorides, sulphates and dissolved oxygen increase corrosion;
- Deposits pitting and under-deposit corrosion;
- Flow velocity low velocity can allow deposition; increases in flow or turbulence can increase corrosion in flow accelerated corrosion (FAC) susceptible piping.

Carbon and low alloy steels will generally degrade uniformly over their entire surface if the material is of uniform composition and environmental conditions are unvarying. However, if surface discontinuities are present (e.g. sulphide inclusions, deposits or scratches), corrosion pits can occur which become self-propagating once initiated. For buried components this is the most common form of degradation and under the worst conditions can result in through-wall breaches in relatively short time periods.

In Ref. [90] the authors define three different forms of corrosion groups (shown pictorially in Fig. 27):

- Group I: Corrosion problems readily identifiable by visual examination.
- Group II: Corrosion damage that may require supplementary means of examination for identification.
- Group III: Corrosion specimens for these types should usually be verified by microscopy.

Each group will be described in the following sections. Group I contains the corrosion types most typically found in buried piping systems. Corrosion of coatings and corrosion mechanisms associated with coating failure are discussed in Section 4.3.14.8.

4.3.3.1. Group I corrosion forms

(a) Uniform corrosion

Uniform corrosion (Fig. 28) is metal loss occurring essentially uniformly over the exposed surface. Most components are built with a corrosion allowance that represents expected metal loss over the component life. CP or the use of coatings or paints can also be used to address uniform corrosion.

Corrosion rates greatly depend on fluid oxygen concentration, pH, flow and temperature. Figure 29 presents the effect of dissolved oxygen on corrosion rate for service water piping. A pH below 4 increases corrosion rates of mild steel and at a pH of 3 corrosion rates increase dramatically. Metals such as aluminium and lead that can





FIG. 27. Main forms of corrosion attack regrouped by ease of identification [56].



FIG. 28. Uniform corrosion (courtesy of EPRI) [91].

react as either an acid or a base, known as amphoteric metals, also show an increase in the corrosion rate in alkaline environments.



FIG. 29. Effect of dissolved oxygen on corrosion rate (courtesy of EPRI) [91].

(b) Pitting corrosion

Pitting is localized corrosion on exposed surfaces. It often occurs in passive alloys, requires breakdown of the passive film and is influenced by both material and surrounding environment. Pitting can occur at surface deposits (under-deposit corrosion), due to electrical imbalances or other initiating mechanisms. Pitting is often initiated by localized chemical or mechanical damage to protective oxide films, localized damage to or poor application of protective coatings or non-uniformities in the component metal structures (e.g. non-metallic inclusions). Water chemistry factors include acidity, low dissolved oxygen concentrations (which tend to render a protective oxide film less stable) and high concentrations of chloride (as in sea water).

Once a pit initiates, it can penetrate to great depth, including through-wall penetration, in a fairly short time. Pitting corrosion rates are 10–100 times faster than uniform corrosion rates. Propagation is much easier than initiation. Once pitting is initiated, the pit will keep growing as long as the environmental conditions are conducive to pit growth. Sometimes a pit may become inactive if environmental conditions change, but it can also grow until it breaks through the wall of the pipe. Figure 30 shows an example of pipe pitting.

(c) Crevice corrosion

Crevice corrosion is a localized form of corrosion usually associated with a stagnant solution on the microenvironmental level [92]. It appears at geometric discontinuities such as gaps and contact areas between parts, under gaskets or seals, inside cracks and seams or at spaces filled with deposits, etc. As shown in Fig. 31 it produces a concentration cell that establishes and maintains local anodic areas by keeping the solution inside the crevice stagnant. This impedes movement of cations into and anions out of the crevice [91].

Crevice corrosion is very similar to pitting corrosion and alloys resistant to one are generally resistant to both. Penetration depth and propagation rates in pitting corrosion are, however, significantly greater than in crevice corrosion.

Some phenomena occurring within the crevice may be reminiscent of galvanic corrosion. Galvanic corrosion, however, consists of two connected metals within one single environment, whereas crevice corrosion consists of one metal part and two connected environments.

Metal dissolution occurs both inside and outside of the crevice. Initially, the inside and outside of the crevice will behave identically. For cathodic half-reactions such as oxygen reduction, however, the limited communication between the metal surface and environment inside and outside of the crevice prevents cathodic processes from



FIG. 30. Example of pitting that led to drilling of pipe: (left) outer diameter; (right) inner diameter (courtesy of EDF).



FIG. 31. Crevice corrosion.

occurring inside the crevice as oxygen is quickly consumed. Corrosion inside and outside of the crevice will continue, much as it did prior to oxygen depletion inside the crevice; however, an excess of positively charged metal ions inside the crevice will attract mobile anions. When aggressive anions such as chlorides migrate into the crevice, the anodic half-reaction inside will be accelerated. The solution inside the crevice may become highly acidic as an insoluble metal hydroxide precipitates from the aqueous solution of metal chloride. An example of crevice corrosion is shown in Fig. 32.

Crevices can develop a local chemistry which is different from that of the fluid within the pipe. 'Concentration factors' of many millions are not uncommon for common water impurities like sodium, sulphate or chloride. For neutral pH solutions, pH inside a crevice can drop to 2, a highly acidic condition that accelerates corrosion of most metals and alloys.

A form of crevice corrosion in which aggressive chemistry buildup occurs under a breached protective film is called 'filiform corrosion'. This can occur under painted or plated surfaces when moisture permeates the coating. Lacquers and 'quick-dry' paints are most susceptible to the problem. It normally starts at small, sometimes microscopic, coating defects.



FIG. 32. Crevice corrosion of a nut and bracket in several locations (courtesy of Cox Engineering) [93].

Another form of crevice corrosion is called corrosion under insulation (CUI), which is external corrosion of piping and vessels fabricated from carbon-manganese, low alloy and austenitic stainless steels that occurs underneath externally clad or jacketed insulation due to water penetration. CUI tends to remain undetected until insulation and cladding or jacketing are removed to allow inspection or when leaks to atmosphere occur [94].

CUI of carbon-manganese steels and low alloy steels usually occurs when a number of conditions are fulfilled. Water or moisture must be present on the substrate to allow oxygen corrosion to occur. Water ingress is due to breaks in the insulation, cladding or jacketing which may have resulted from poor installation, damage during service or deterioration over time. Water sources can be external (e.g. rainwater, deluge systems, process liquid spillage) or the result of condensation. This water may be retained depending on the absorption properties of the insulation material and the operating temperature. Depending upon process conditions, saturated insulation may never have the opportunity to dry out completely.

Corrosion of austenitic stainless steels usually manifests itself as chloride external SCC (CI-ESCC).

Contaminants that can cause problems on both carbon-manganese steels and low alloy steels as well as on austenitic stainless steels need to be present. Chlorides and sulphides make up the bulk of the contamination and generally increase water corrosivity. The source of contaminants can be external or can be produced by leaching from the insulation material itself. In the presence of an applied or residual stress and temperature exceeding 60°C (140°F), high chloride content of water contributes to Cl-ESCC.

Insulation type may only be a contributing factor since CUI has been reported under all types of insulation. However, individual insulation characteristics can influence the rates at which CUI occurs. These include:

- Presence of water-leachable contaminants such as chlorides and sulphates;
- Water retention, permeability and wettability of the insulation (to prevent wetting of insulation, jacketing or other water resistant covering should be considered);
- Residual compounds which may react with water to form hydrochloric or other acids;
- Annular spaces or crevices for retention of water and other corrosive media;
- Water absorption properties of the insulation;
- Insulation contaminants that may increase or accelerate corrosion rates;
- Anodic reactions at the substrate surface may be caused by anode/cathode corrosion cell activity in a low
 resistance electrolyte which may be at an elevated temperature or subject to cyclic temperature variations.

CUI starts due to the presence of water, oxygen and other contaminants. Once water and oxygen are present on steel surfaces, corrosion occurs through metal dissolution. It follows that the insulation system that holds the least amount of water and dries most quickly should result in the least amount of corrosion damage to equipment.

CUI rates are determined by availability of oxygen, contaminants in water, temperature, heat transfer properties of the metal surface and surface conditions (wet or dry). This in turn is influenced by insulation material properties. Damage can be general or localized. Service temperature is an important property as illustrated in Fig. 33, which shows the effect of temperature on the corrosion rates of insulated carbon-manganese steels and introduces the concept of a closed system in which oxygenated water evaporation is limited, resulting in increased corrosion rates at higher temperatures. This is why CUI is such a problem, since corrosion rates are often greater than anticipated.

(d) Galvanic corrosion

Galvanic corrosion (also called 'dissimilar metal corrosion') is an electrochemical process in which one metal corrodes preferentially to another when both metals are in electrical contact and immersed in an electrolyte. The rate of corrosion depends in part upon electrolyte conductivity (which is a function of its concentration).

When a galvanic couple forms, one metal in the couple becomes the anode (i.e. the less noble material) and corrodes more quickly than it would on its own, while the other metal becomes the cathode (i.e. the more noble material) and corrodes more slowly than it would alone.

The relative nobility of a material can be predicted by measuring its corrosion potential. The electrochemical potential of metals in sea water forms the well-known galvanic or electromotive force (EMF) series (Table 16). A small anode to cathode area ratio is highly undesirable; in this case, galvanic current is concentrated onto a small anodic area and the anode suffers a rapid loss of thickness.



FIG. 33. Corrosion rate as a function of temperature [94].

TABLE 16. EXAMPLE GALVANIC SERIES FOR SELECTED ALLOYS IN SEA WATER FLOWING AT 2.4–4.0 M/SEC FOR 5–15 DAYS AT 5–30°C [91]

Magnesium	
Zinc	
Aluminium alloys	
Cadmium	
Iron or mild steel	
Low alloy steel	
Type 430 stainless steel (active)	
Type 304 stainless steel (active)	
Type 316 stainless steel (active)	
Lead	
Muntz metal	
Naval brass	
Admiralty brass	
Aluminium bronze	
Copper	
90/10 copper-nickel	
Type 430 stainless steel (passive)	
70/30 copper-nickel	
Monel alloy 400	
Type 304 stainless steel (passive)	
Type 316 stainless steel (passive)	
Alloy 20 stainless steel	
Titanium	
Graphite	
Most noble (most positive potential)	

Most active (most negative potential)

Using materials with a similar electrochemical potential in the galvanic series should minimize the corrosion rate. Unfortunately, the series (which lists pure metals in solutions of their own ions) bears little relationship to actual applications. Consequently, galvanic series predictions are likely to be reliable only where there is a very large difference in electrode potential. An example might be aluminium versus copper, where in most circumstances, aluminium would sacrifice itself to protect copper in a conductive electrolyte.

If cathodic reactants cannot be eliminated, a secure method of minimizing atmospheric or environmental galvanic corrosion is to electrically insulate dissimilar material connections (for example, where pipe material changes are made). Galvanic corrosion can also be minimized by avoiding assemblies where small anodic components are attached to large cathodic components.

Note that the term 'dissimilar materials' most often relates to metals of a different chemical composition, but can also apply to the same metals in different conditions. For example, new buried steel pipework in contact with old buried metallic pipework which has acquired a surface layer of corrosion products can also form a galvanic couple.

Figure 34 shows a potential scenario in which galvanic corrosion could be initiated, while Fig. 35 illustrates an actual case of preferential dissolution of CS in a CS/stainless steel couple in a nuclear power plant's service water piping (river water).

(e) Stray current corrosion

Stray currents (or interference currents) are defined as those currents that follow paths other than intended. Stray currents from direct current (DC) power lines, substations or street transit systems, for instance, can flow into a pipe system or other steel structure and cause corrosion. Alternating (AC) lines may also occasionally cause corrosion, as can application of excessive CP current to a metal structure. Transient geomagnetic activity may also induce stray currents (called telluric effects), however, due to their short duration major corrosion as a result of



FIG. 34. Possible galvanic corrosion scenario.



FIG. 35. Galvanic attack and corrosion product buildup on carbon steel/stainless steel: (a) view from carbon steel side; (b) view from stainless steel side (courtesy of EPRI) [91].

such activity is rare. Stray currents can induce step or touch voltages on objects through which they flow, causing potential personnel safety hazards.

Grounding grids ensure that stray current corrosion is not a typical concern at nuclear power plants. Stray currents can, however, originate from grounded DC systems, welding machines or a CP system operating on a nearby pipeline or structure outside of the plant ground grid.

Corrosion resulting from stray currents is similar to that from galvanic corrosion (Section 4.3.3.1(d)) and corrosion rates are affected by soil and water conditions in the same manner. Nearly all stray currents are local and concentrated, ensuring that accelerated corrosion will occur. Chemical and electrical reactions occur in the electrolyte and at the metal–electrolyte interfaces. Specifically, the corroding metal is considered the anode from which current leaves to flow to the cathode. Different metals will experience different amounts of weight loss degradation when exposed to the same current discharge. Soil and water characteristics affect corrosion rates in the same manner as with galvanic-type corrosion.

Insulating flanges can cause corrosion from stray currents. Usually, insulating flanges separate pipes of different material (to minimize galvanic corrosion) or those with different levels of CP. If current collects on the pipe downstream of the protected pipe, it may flow back to the insulated flange, discharge into the ground on one side of the flange and flow to the other side of the flange that is connected to the protected pipe.

A schematic of stray current corrosion resulting from being in proximity to a CP system's anode (anodic interference) is shown in Fig. 36. Similar mechanisms can develop at CP system cathodes (cathodic interference).

Figure 37 shows an example of stray current corrosion of a copper water pipe.



FIG. 36. Stray current anodic interference.



FIG. 37. Stray current corrosion of a copper water pipe (courtesy of R. Craig Jerner, JEI Metallurgical Inc.) [95].

4.3.3.2. Group II corrosion forms

(a) Flow accelerated corrosion

Flow accelerated corrosion (FAC) is a major concern in power plant systems. FAC is a corrosion process whereby the normally protective oxide layer on carbon or low alloy steel dissolves into a stream of flowing water or wet steam. Failures can be catastrophic in nature and have resulted in a number of deaths in the nuclear and other

power generation industries. FAC rates depend on a number of factors such as flow velocity, piping material and type of flow (e.g. single phase versus two phase). Examples of FAC failure are shown in Fig. 38.

FAC will be covered in more detail in a future IAEA Nuclear Energy Series publication, No. NP-T-3.15 [97].

(b) Cavitation

Cavitation (Fig. 39) occurs when fluid pressure at the vena contracta³ falls below the vapour pressure, thus creating a negative pressure. Hence vapour bubbles appear and then collapse as pressure recovers. This collapse may result in pitting of the surfaces on which they occur and can lead to severe erosion or corrosion issues.



FIG. 38. Flow accelerated corrosion failures: (left) failed pipeline schematic showing fracture surface location, welds and flow measurement orifice meter; (right) circumferential fracture and excessive thinning at fracture location (both from Ref. [96]).



FIG. 39. Cavitation damage in a 15.2 cm (6 in) diameter pipe downstream of a flow controller (courtesy of EPRI) [98].

³ Vena contracta is the point in a fluid stream where the diameter of the stream is the least and fluid velocity is at its maximum, such as in the case of a stream issuing out of a nozzle.

This condition can even form an airlock which prevents any incoming fluid from offering cooling effects, further exacerbating the problem.

Locations where this phenomenon is most likely to occur are at pump suctions, valve or regulator discharges or other geometry-affected flow areas such as pipe elbows and expansions.

(c) Fretting

Fretting corrosion refers to corrosion damage at contact surface asperities⁴. This form of damage is induced under load and in the presence of repeated relative surface motion, as induced, for example, by vibration.

(d) Intergranular corrosion

Intergranular corrosion (IGC) (Fig. 40) is a form of corrosion in which a narrow path is corroded out preferentially along metallic grain boundaries. It often initiates on a surface and proceeds by local cell action near grain boundaries.

This form of corrosion may greatly affect the mechanical properties of materials.

(e) Exfoliation

Exfoliation is a form of intergranular corrosion that proceeds laterally from initiation sites along planes parallel to the surface. Since corrosion products have a greater volume than metal, exfoliation will force layers apart, causing the metal to delaminate. Exfoliation is also known as layer corrosion.

Aluminium alloys are susceptible to exfoliation as shown in Fig. 41.



FIG. 40. Stainless steel cavernous pits formed on S30400 stainless steel following intergranular corrosion attack (courtesy of Russ Green, TMI) [56].

⁴ Surfaces, even those polished to a mirror finish, are not truly smooth on an atomic scale. They are rough, with sharp, rough or rugged projections, termed 'asperities'.

(f) Dealloying (selective leaching)

Dealloying is selective removal by corrosion of one element of an alloy by either preferential attack or by dissolution of matrix material. It may occur uniformly or locally (plug dealloying). Examples are shown in Fig. 42.

Copper alloys with > 15% Zn or > 8% Al are sensitive to dealloying aqueous environments such as those found in service water systems. This specific form of dealloying for copper–zinc alloys is known as dezincification.

Graphitic corrosion is a form of dealloying of iron from cast iron, where iron gets removed and graphite grains remain intact.

Selective leaching is usually controlled by material selection and in the case of aluminium bronzes, via control of heat treatment. Brass is resistant to dezincification if traces of arsenic, phosphorous or antimony are added to the alloy [60].



FIG. 41. Lamellar corrosion exfoliation of aluminium alloy (A97075) [56].



FIG. 42. Dealloying — plug type (aluminium brass) at top and layer type (Muntz metal) at bottom (courtesy of EPRI) [91].

4.3.3.3. Group III corrosion forms

(a) Environmental cracking

Environmental cracking (EC) is an acute form of localized corrosion. Cracks may significantly impact on the structural integrity of piping. For instance, deep cracks may change failure modes from where failure only occurs when stresses are very high and produce extensive deformation, to where brittle rather than ductile overload types of failure occur.

Cracking can also produce leakage and increase corrosion rates (e.g. corrosion from inside in a PCCP/RCCP).

The main forms of EC are SCC, fatigue corrosion and hydrogen embrittlement. When stainless steel or aluminium is used in buried applications, consideration of soil conditions may result in the need for appropriate protection to mitigate EC.

(i) Stress corrosion cracking

Stress corrosion cracking (SCC) (Fig. 43) is crack initiation and subcritical crack growth of susceptible alloys under the influence of tensile stress and a 'corrosive' environment. It may generate sudden failure of normally ductile metals subjected to a tensile stress, especially in metals at elevated temperatures. It is a complex phenomenon driven by the interaction of mechanical, electrochemical and metallurgical factors. SCC may have transgranular (through the grains) or intergranular (along grain boundary) morphology.

SCC often progresses rapidly and is more common among alloys than pure metals. A balance between a corrosive environment and mechanical stresses must be met for SCC to occur, since this phenomenon is generated by both mechanical stresses and corrosion.

Operating experience for nuclear power plants related to SCC is discussed in IAEA Nuclear Energy Series No. NP-T-3.13 [100]. Table 17 lists some environments in which SCC has been observed for at least some alloys of the materials listed.

- Transgranular stress corrosion cracking

Transgranular stress corrosion cracking (TGSCC) (Fig. 44) is a form of SCC in which cracks form between or across grain boundaries. It is caused by aggressive chemical species, especially if coupled with oxygen and combined with high stresses.

- Intergranular stress corrosion cracking

Intergranular stress corrosion cracking (IGSCC) (Fig. 45) is a form of SCC in which cracks form between or along grain boundaries. It is associated with a sensitized material (e.g. sensitized austenitic stainless steels are



FIG. 43. Stress corrosion cracking cross-section showing typical branched cracks [99].

Material	Environment
CSs	NaOH solutions; NaOH-NaSiO ₃ solutions; CaNO ₃ , NH ₄ NO ₃ and NaNO ₃ solutions; mixed acids, $(H_2SO_4-HNO_3)$; HCN; H_2S ; sea water; NaPb alloy
Stainless steels	$BaCl_2$, $MgCl_2$ solutions; NaCl-H ₂ O ₂ solutions; sea water, H ₂ S, NaOH-H ₂ S solutions
Aluminium alloys	NaCl-H ₂ O, NaCl solutions, sea water, mercury
Copper alloys	Ammonia vapours and solutions, mercury
Inconel	Caustic soda solutions
Nickel	Fused caustic soda

TABLE 17. SOME SCC ENVIRONMENTS FOR METALS (ADAPTED FROM REF. [56])



FIG. 44. Transgranular stress corrosion cracking of stainless steel [101].

susceptible to IGSCC in an oxidizing environment). Sensitization of unstabilized austenitic stainless steels is characterized by precipitation of a network of chromium carbides with depletion of chromium at grain boundaries, making these boundaries vulnerable to corrosive attack.



FIG. 45. Intergranular stress corrosion cracking of stainless steel [100].

Primary water SCC (PWSCC) is a form of IGSCC and is defined as intergranular cracking in primary water within specification limits (i.e. no need for additional aggressive species).

Irradiation assisted SCC (IASSC) refers to intergranular cracking of materials exposed to ionizing radiation. As with SCC, IASCC requires stress, an aggressive environment and a susceptible material. However, in the case of IASCC, a normally non-susceptible material is rendered susceptible by exposure to neutron irradiation. IASCC is a plausible ageing mechanism for nuclear power plant internal components.

(ii) Corrosion fatigue

Fatigue is a progressive and localized structural damage that occurs when a material is subjected to cyclic loading (see Section 4.3.5).

When subjected to cyclic stress in a corrosive environment, the number of cycles required to cause failure for a metallic pipe at a given stress may be lower than for the same metal in an air environment. This phenomenon, called 'corrosion fatigue', is presented in Fig. 46.

Corrosion fatigue effects are usually not significant in service water systems since corrosion processes will tend to be much faster, so that risk of failure by cyclic mechanical loads is very low.

(iii) Hydrogen embrittlement

Hydrogen embrittlement is sometimes classified separately from SCC. It refers to embrittlement and resulting increased cracking risk due to uptake of hydrogen into material structures. The cathodic reduction of water to form hydrogen is a potential source of embrittlement [60]. Hydrogen stress cracking and sulphide stress cracking are terms used for hydrogen embrittlement from interactions with hydrogen gas and hydrogen sulphide, respectively.

(b) High temperature attack

High temperature attack is corrosion that initiates at higher temperatures, either through scaling or internal attack.



FIG. 46. Fatigue and corrosion fatigue curves for an aluminium alloy [102].

(i) Scaling

Scaling or precipitation fouling is the deposition of mineral solids on the interior surfaces of water lines and containers. It usually occurs when water containing carbonates or bicarbonates of calcium and magnesium is heated. Changes in temperature, solvent evaporation or degasification cause concentrations to exceed saturation levels, leading to their precipitation.

(ii) Internal attack

Internal attack of metals can occur at high temperatures and is sometimes referred to as dry corrosion or scaling [56]. High temperature materials are used in a wide variety of industries, including power generation (notably gas turbines), and the temperatures involved are increasing. Such high temperatures are, however, typically above those experienced by buried or underground piping and tanks used at nuclear power plants.

Any metal exposed to oxygen at high temperatures reacts with the oxygen. Oxygen is absorbed on the surface and may then react to form an oxide. If the film or scale is continuous, adherent and non-porous a degree of protection from further reaction is afforded. The degree of protection depends upon film thickness and rates at which reactants can diffuse through the film, i.e. oxygen moving in and/or metal moving out. Oxidation scale breakdown can result from thermal cycling, fluid dynamics, chemical reactions or mechanical forces. Catastrophic oxidation occurs when the metal reacts with oxygen at continuously increasing rates. This reaction can occur if the surface temperature of the metal continuously increases, volatile oxides are formed or a low-melting eutectic oxide forms beneath the scale. Internal oxidation products penetrate the applicable metal and can reduce its strength, causing it to swell, distort or burst.

In environments containing high sulphur concentrations, similar sulphide scales form at high temperatures instead of oxide scales. Such scales are less protective than oxide scales.

To minimize high temperature oxidation one can use a material that is stable at the operating conditions of interest, modify operating conditions or limit the high temperature exposure.

4.3.3.4. Corrosion associated with organisms

(a) Biofouling

Biofouling or biological fouling is the undesirable accumulation of microorganisms on surfaces such as buried pipes. Cooling water systems, especially open recirculation systems, are susceptible to a wide variety of growth,

including bacteria, algae and fungi. Once bacteria settle on a surface, the organisms secrete a polysaccharide layer for protection. This film accumulates silt and other solids which continue to grow and isolate the organisms from chemical treatment. Biofilms develop slowly at first but growth accelerates once populations become established. Anaerobic bacteria can thrive underneath a deposit and lead to the formation of acids, sulphides and so on that can attack exposed metal and lead to pitting.

Microorganisms tend to attach themselves to solid surfaces, colonize, proliferate and form biofilms which may in turn produce an environment at the biofilm/metal interface that is different from normal in terms of pH and dissolved oxygen. Biofilm formation steps are shown in Fig. 47.

Biofouling can be accompanied by MIC.

(b) Microbiologically influenced corrosion

Microbiologically influenced corrosion (MIC) is the interaction of biofilms or the by-products of their metabolism with corrosion processes. These microorganisms create local corrosive environments significantly different from the bulk fluid. MIC can afflict CSs, copper alloys, stainless steels and even non-metallic pipes. Since biofilms tend to create non-uniform surface conditions, localized attack may start at some surface points leading to localized corrosion, usually in the form of pitting. The presence of MIC can require additional levels of CP current in order to provide adequate protection.

Some recent experiments have demonstrated that the most severe corrosion is due to microorganisms directly oxidizing metallic iron for energy and thus the term 'microbially induced corrosion' (as opposed to influenced) can be more correct in some situations [103].

Examples of MIC in CS piping and stainless steel weld metal are shown in Fig. 48. NACE has prepared guide TM0106 [104] on how to specifically address MIC in buried piping systems. Figure 49 shows some different ways in which microorganisms can impact on buried steel pipe.

4.3.4. Liquid droplet impingement

Liquid droplet impingement (LDI) occurs when water droplets strike metal surfaces at high velocity. The phenomenon occurs in pumps, valves, orifices and at elbows and tees in pipelines (Fig. 50).

The forces causing deformation during impact are the initial load normal to the metal pipe surface due to drop deceleration and the shear force exerted on the metal surface by high velocity flow away from the impact point. Both forces combine and are responsible for erosion damage and metal removal from the pipe wall. Impingement corrosion usually produces a pattern of localized attack with directional features.

An example of a ruptured pipe with a hole caused by LDI is shown in Fig. 51 [105].



FIG. 47. Biofilm formation steps: Formation is initiated when small organic molecules become attached to an inert surface (1) and microbiological cells are adsorbed onto the resulting layer (2). Cells send out hair-like exopolymers to feed on organic matter (3), adding to the coating (4). Flowing water detaches some of the formation (5), producing an equilibrium layer [56].



FIG. 48. Microbiologically influenced corrosion (MIC) examples: (left) MIC of 30.5 cm (12 in) carbon steel piping after outside coating removal; (right) MIC in stainless steel weld metal (courtesy of EPRI) [91].



FIG. 49. Mechanisms by which microorganisms impact on buried mild steel pipes [103].

- (A) Anaerobic methanogens and sulphate reducing microorganisms extract electrons directly out of steel, producing Fe²⁺;
- (B) Anaerobic iron oxidizing microorganisms that utilize nitrate as an electron acceptor oxidize Fe^{2+} and produce Fe^{3+} , which precipitates as iron oxide;
- (C) Anaerobic heterotrophic microorganisms reduce insoluble Fe^{3+} oxides, producing Fe^{2+} ;
- (D) Anaerobic sulphate reducing microorganisms reduce sulphates, utilizing them as terminal electron acceptors. They produce OH⁻, PH₃, H₂S, FeS precipitates that can increase corrosion rates. Connecting lines indicate nanowires;
- (E) Heterotrophic microorganisms produce organic acids and enzymes that attack steel. They also consume oxygen, creating an oxygen gradient within biofilms with anoxic regions at the bottom, and recycle nutrients for other microorganisms;
- (F) Sulphur oxidizing microorganisms produce sulphuric acid;
- (G) Neutrophilic iron oxidizing bacteria with precipitated iron oxides forming a mat create differential aeration cells and galvanic cells;
- (H) Diatoms and cyanobacteria produce oxygen on the surface of soil, creating differential aeration cells and forming H₂O₂. Some plant roots release oxygen deeper in soil;
- (I) Other microorganisms;
- (J) Hydrogen peroxide produced by aerobic soil micro-organisms attacks steel.



FIG. 50. Thinning of piping wall due to droplet impingement.



FIG. 51. Small hole as a result of pipe thinning and schematic drawing [105].

4.3.5. Fatigue

Fatigue (Fig. 52) is progressive and localized structural damage occurring when a material is subjected to cyclic loading. Nominal maximum stress values are less than ultimate tensile stress limits and may be below a material's yield stress limit.

If loads are above a certain threshold, microcracks will initiate at or below surfaces and grow until a crack reaches a critical size, leading to structural failure. Coatings may prevent detection of this phenomenon.

4.3.6. Tuberculation and occlusion

Tuberculation (Fig. 53) is the development of rounded bulges or protuberances on pipe surfaces. When tuberculation occurs inside of a pipe, buildup of corrosion products or deposits can decrease flow carrying capability (called occlusion; Fig. 54).

Occlusion can be caused by such things as debris, macrofouling and corrosion products. Degradation is more common in smaller pipes since the cause of the blockage (e.g. corrosion products, which are less dense than underlying material), can 'impinge' upon each other, thus producing a flow restriction. In larger diameter pipes, the same volume of corrosion products or blocking material will be a smaller fraction of a pipe's cross-sectional area.

Corrosion product buildup can affect flow carrying capability due to increases in surface roughness, even before pipe cross-sectional areas are significantly degraded.



FIG. 52. Fatigue pipe fracture [106].



FIG. 53. Structural features of a typical tubercle [107].

4.3.7. Settlement, soil displacements and other external loads

Soft soil conditions or environmental condition changes, such as groundwater elevation, may lead to pipe deformation or even failure (Fig. 55).

Permanent ground-induced actions due to earthquakes, such as fault movements, landslides, or liquefactioninduced lateral spreading, are known to be responsible for most seismic damage in oil and gas buried steel pipelines. Operating experience related to nuclear seismic events is covered in Section 4.8.4.

Settlement issues and seismic events may be tough to mitigate; however, some techniques may prevent or limit damage to buried pipes. These include placing piping in tunnels, using ductile pipe material and installing flexible connections.

Other external loads from heavy surface loads, construction activities, frost heave, or soil overburden can also result in stresses on piping and tanks and can lead to deformation and degradation.

4.3.8. Wear

Wear is loss of surface material due to movement between two contacting surfaces. Fretting is a form of wear characterized by minute relative motion caused by vibration or some other force.



FIG. 54. Occlusion of service water piping at Catawba nuclear power plant [108].



FIG. 55. Schematic representation of a pipeline crossing a strike slip fault at a crossing angle [109].

4.3.9. High density polyethylene degradation mechanisms

HDPE has three main degradation mechanisms (UV radiation, SCG and improper fusion) and a rarer ductile failure mode. HDPE pipe's typical operating temperature range is from -40° C to 60° C although some products may be pressure rated for service as high as 82°C. Chemical resistance of HPDE material varies with formulation, with cross linked HPDE generally being more resistant to chemical attack. Resin formulations have been improved over time.

4.3.9.1. Ultraviolet radiation

Like every plastic, HDPE's resistance to UV radiation is poor: it will break down and become weak in UV light. This, however, is not an issue with buried pipework. If needed, HDPE may be protected from UV by a coating, or through use of a UV stabilizer.

4.3.9.2. Slow crack growth and ductile failures

SCG is the primary mode of failure in service for HDPE piping. It is characterized by low-ductility slit-like failures with little gross deformation of the area surrounding the failure.

Regardless of failure mode, failure times decrease exponentially with increasing sustained temperatures.

The relationship between ductile and SCG slit-like failure modes as functions of hoop stress and temperature is shown in Fig. 56. The transition from ductile failure to SCG failure is indicated by the curve's knee.

4.3.9.3. Improper fusion

HDPE joints are usually fabricated via a fusion process. Good pipe joints will fail in a ductile manner, whereas improperly made pipe joints will fail in a brittle manner. Fused joints sampled during construction are typically tested until failure (failure must be ductile). Joints are also inspected for voids, cold fusion, and particulate contamination.

It should be noted that since HDPE creeps under load, fusion joints are the preferred primary method of connecting HDPE pipes. When correctly implemented, fused joints are self-restraining and leakproof. In some instances conditions are not conducive to properly fusing the joint per manufacturers' recommendations (e.g. transition to another pipe material or in some repair circumstances). In these cases mechanical fittings to join or repair HDPE are a secondary and limiting choice and must be carefully utilized.

4.3.10. Fibre reinforced plastic degradation mechanisms

Structural failure can occur in FRP materials when:

- Tensile forces stretch the matrix more than the fibres, causing the material to shear at the interface between matrix and fibres;
- Tensile forces near the end of the fibres exceed the tolerances of the matrix, separating the fibres from the matrix;
- Tensile forces exceed the tolerances of the fibres, causing the fibres themselves to fracture, leading to material failure.

FRP is used extensively in contact with many grades of water. Most applications involve general purpose resins, but if dealing with hot water, more chemically resistant resins with appropriate heat distortion properties must be used. Unlike with metals, a higher salt or electrolyte content represents less of a potential attack to FRP. This is because dissolved salts diminish ion migration effects which can allow reactions with the fibreglass reinforcement. Distilled water is more aggressive than tap water and can effectively act as a solvent [110].



FIG. 56. Schematic of hydrostatic test results for high density polyethylene piping showing ductile and slow crack growth (SCG) failure regions. Knee in curve indicates transition from ductile failure mode to SCG failure mode [20].

4.3.11. Concrete degradation mechanisms

Concrete is a base material in civil engineering. Concrete may be used on some pipework, especially when dealing with water systems. Conditions and stressors that may result in concrete degradation of typical underground piping are:

- Physical attack:

- Salt crystallization;
- Freezing and thawing attack;
- Abrasion, erosion and cavitation;
- Fatigue/vibration;
- Settlement.
- Chemical attack:
 - Efflorescence and leaching;
 - Sulphate attack;
 - Acids and bases;
 - Alkali-aggregate reactions (AAR);
 - Aggressive marine water;
 - Biological attack (including MIC).

The specific case of concrete piping with a steel cylinder core will be described in Section 4.3.11.4.

Detailed information on concrete ageing management and degradation mechanisms in nuclear power plants is contained in IAEA Nuclear Energy Series No. NP-T-3.5 [111].

4.3.11.1. Physical attack

(a) Salt crystallization

The movement of salt solution causes physical salt attack by capillary action through concrete and its subsequent crystallization through drying. The process is repeated through wetting and drying cycles. Figure 57



FIG. 57. Concrete slab experiencing deterioration due to salt crystallization after one year of exposure; arrows indicate concrete surface deterioration and lines the level of solution in wetting cycle (copyright 2005 CSIRO Australia; reproduced with permission) [112].

presents a concrete slab after a one-year exposure to cyclic wetting and drying in sulphate solutions [112]. Crystallization and recrystallization of certain salts (e.g. NaCl, $CaSO_4$ and $NaSO_4$) can generate expansive forces resulting in physical concrete breakdown. The mechanism is similar to water freezing and thawing. Structures in contact with fluctuating water levels or in contact with groundwater containing large quantities of dissolved salts are susceptible to this deterioration. Above ground moisture is drawn to the concrete surface where it evaporates, leaving salt crystals growing near surface pores. The result is a deteriorated area just above ground level. Salt crystallization problems are minimized with low permeability concretes and where sealers or barriers have been applied to prevent water ingress or subsequent evaporation.

(b) Freeze-thaw and thermal cycling

When water freezes, it expands by about 9%. As water in moist or cracked concrete freezes, it produces pressure in concrete pores. If the pressure exceeds concrete's tensile strength, the cavity will dilate and break. The cumulative effects of freeze-thaw (FT) cycles and disruption of paste and aggregate may lead to expansion and cracking, scaling and even concrete crumbling.

Deterioration of concrete by FT actions may be difficult to diagnose as other types of deterioration mechanisms such as alkali-silica reactions (see Section 4.3.11.2(d)) often go hand in hand with FT. Typical signs of FT are:

- Spalling and scaling of surfaces;
- Large chunks (centimetre-sized) coming off;
- Exposing of aggregate;
- Usually exposed aggregate is uncracked;
- Surface parallel cracking.

Thermal cycling at higher temperatures can be an issue at hot locations within nuclear power plants and can cause similar concrete spalling to FT cycles and concrete strength loss.

(c) Abrasion and cavitation

Abrasion occurs when solids transported in water flowing over the concrete surface abrade the concrete, causing surface pitting and aggregate exposure. Water flowing around certain concrete surface profiles can cause cavitation (negative pressure) at concrete surfaces resulting in pitting [98].

(d) Fatigue

Fatigue in concrete occurs similarly to that in metals as described in Section 4.3.5.

(e) Settlement

Settlement can impact on concrete similarly to metals as described in Section 4.3.7.

Concrete structures and components susceptible to settlement are those built with minimum foundations, those subject to large fluctuations in water table elevation and those subject to soil erosion and improper drainage.

4.3.11.2. Chemical attack

(a) Efflorescence and leaching

Efflorescence is a crystalline deposit of salts, usually white, occurring on or near concrete surfaces following percolation of a fluid (e.g. water) through the material, either intermittently or continuously, or when an exposed surface is alternately wetted and dried. Occasionally efflorescence may be a symptom of chemical reactions such as sulphate attack, or it may indicate leaks in water retaining structures or undesired leakage of moisture through a structure. Typically efflorescence is primarily an aesthetic problem rather than one affecting mechanical properties

or durability. In rare cases, excessive efflorescence deposits can occur within concrete surface pores causing expansion that may disrupt the surface [113]. Figure 58 shows efflorescence in a water retaining structure.

Leaching of cementitious materials involves transportation of ions from a material's interior through its pore system outwards into its surroundings. In the leaching process solid concrete compounds are dissolved by water and are transported away by diffusion based on concentration gradients, or convection through water flow. Induced leaching of calcium hydroxide from concrete may cause an increase in porosity and permeability and a decrease in mechanical strength. Leaching also lowers concrete's pH, which threatens the rebar's protective oxide layer and may lead to carbonation.

(b) Sulphate attack

All sulphates are potentially harmful to concrete. Sulphate attack of concrete is caused by exposure to excessive amounts of sulphate from internal or external sources. Internal sulphate attack occurs when a soluble source of sulphates is incorporated into concrete at the time of mixing, due to the presence of natural gypsum or pyrite in the aggregate and admixtures. External sulphate attack is most common and occurs when water containing dissolved sulphates penetrates the concrete. The sulphates react with calcium hydroxide and if enough water is present, will cause expansion and irregular concrete cracking and thus progressive loss of strength and mass. The degree of sulphate attack depends on water penetration, the sulphate salt, its concentration and type, the means by which salt develops and concrete binder chemistry. The results of sulphate attack can be excessive expansion, delamination, cracking and loss of strength. Figure 59 illustrates the mechanism of sulphate (sodium) attack and presents an example of the resultant cracking. It has been reported that at a concentration of about 0.2% sulphate content in groundwater concrete may suffer sulphate attack. Magnesium sulphate can be more aggressive than sodium sulphate and there are three key chemical reactions between sulphate ions and hardened cement pastes: (1) recrystallization of ettringite, (2) formation of calcium sulphoaluminate (ettringite) and (3) decalcification of the main cementitious phase (calcium silicate hydrate) [116].

Concrete pipes and other underground structures may be exposed to attack by sulphates in soil and groundwater. The severest attack occurs on elements where one side is exposed to sulphate solutions and evaporation can take place at the other [117]. Structures subjected to sea water are more resistant to sulphate attack because chlorides present form chloro-aluminates to moderate the reaction. Concretes using cements low in tricalcium aluminate and those that are dense and of low permeability are most resistant to sulphate attack.



FIG. 58. Efflorescence in water retaining structure [114].

A rare form of sulphate attack is through the formation of thaumasite as a result of reactions between calcium silicates in the cement, calcium carbonate from limestone aggregates or fillers and sulphates, usually from external sources [118]. Thaumasite sulphate attack forms slowly and can result in a soft, white, pulpy mass that causes total disintegration of the concrete and exposing rebar. Serious damage to concrete or masonry due to thaumasite formation is, however, uncommon. Figure 60 presents a subsurface concrete pier affected by thaumasite sulphate attack in the United Kingdom.

(c) Aggressive chemical attack

Concrete usually does not have good resistance to acids which may attack concrete by dissolving both hydrated and unhydrated cement compounds as well as calcareous aggregate. In most cases, the chemical reaction



FIG. 59. Concrete cracking due to sulphate attack: (a) mechanism, (b) cracking due to sulphate attack (adapted from Ref. [115] by permission of the International Federation for Structural Concrete/Fédération internationale du béton (fib), (www.fib-international.org.).



FIG. 60. (Left) Thaumasite sulphate attack on subsurface concrete pier and (right) scanning electron microscope image showing thaumasite formation [119, 120].

forms water-soluble calcium compounds, which are leached away. Degradation may be increased in the presence of cracks or near poor joints.

(d) Alkali-aggregate reactions

Aggregates containing certain constituents can react with alkali hydroxides in concrete. Reactivity is potentially harmful only when it produces significant expansion. This alkali-aggregate reactivity (AAR) has two forms [121]: alkali-silica reaction (ASR) and alkali-carbonate reaction (ACR).

ASR is of more concern than ACR since aggregates containing reactive silica minerals are more common.

(i) Alkali-silica reaction

ASR forms a gel that swells as it draws water from surrounding cement paste. Reaction products from ASR have a great affinity for moisture. In absorbing water, these gels can induce pressure, expansion and cracking of aggregate and surrounding paste. The reaction can be visualized as a two-step process:

- (1) Alkali hydroxide + reactive silica gel \rightarrow reaction product (alkali-silica gel);
- (2) Gel reaction product + moisture \rightarrow expansion.

The amount of gel formed in concrete depends on the amounts and types of silica and the alkali hydroxide concentration. Gel presence does not always coincide with distress and thus does not necessarily indicate destructive ASR.

For ASR to occur there must be (1) reactive forms of silica in aggregate, (2) a high-alkali pH pore solution and (3) sufficient moisture. If one of these conditions is absent, ASR cannot occur.

Typical visual indicators of ASR may be a crack network (Fig. 61), closed or spalled joints, relative displacements of different parts of a structure, or fragments breaking off of concrete surfaces (pop-outs) (Fig. 62).

Because ASR deterioration is slow, risk of catastrophic failure is low. However, ASR can cause serviceability problems and can exacerbate other deterioration mechanisms such as those that occur in frost, de-icer or sulphate exposures.



FIG. 61. Map cracking (i.e. pattern cracking or alligator cracking) in a concrete wall due to an alkali-silica reaction [122].



FIG. 62. Pop-outs caused by an alkali-silica reaction of sand-sized particles [121].

The best way to avoid ASR is to take appropriate precautions before concrete is placed. Standard concrete specifications may require modification to address ASR. Careful analysis of cementitious materials and aggregates should be done and a control strategy chosen to optimize effectiveness. If aggregates are not reactive by historical identification or testing, no special requirements are needed.

(ii) Alkali-carbonate reaction

ACR is relatively rare because aggregates susceptible to this reaction are usually unsuitable for use in concrete for other reasons, such as strength potential.

(e) Aggressive marine water

Concrete in service may be exposed to aggressive waters, the most common deleterious ion being sulphate [123] and others being acids and chemical by-products from industrial processes. Some locations have sea water or brackish water in contact with concrete. Most sea water has a pH of 7.5 to 8.4 and contains about 3.5% soluble salts by weight [124]. Concrete exposed to marine environments may deteriorate as a result of the combined effects of chemical action of seawater constituents on cement hydration products, AAR (if reactive aggregates are present), crystallization pressure of salts within concrete (if a structure face is subject to wetting and others to drying), frost action in cold climates, corrosion of embedded rebar and physical erosion due to wave action or floating objects.

(f) Biological attack

Growth on concrete structures, lichen, moss, algae, roots of plants and trees penetrating into concrete at cracks and weak spots may lead to mechanical deterioration from bursting forces causing increased cracking. Such growth can retain water on concrete surfaces, leading to high moisture content and increased risk of deterioration due to freezing. Microgrowth may cause chemical attack by developing humic acid that dissolves cement paste [125]. Formation of capillaries within the concrete during the hydration process and the capillary action of water provide a means for microorganism penetration.

The metabolism of microorganisms results in the excretion of acids that contribute to cementitious material degradation. In environments where reduced sulphur compounds are present, such as sewers, production of sulphuric acid by sulphur oxidizing bacteria (thiobacilli) produces a corroding layer on the concrete surface that penetrates the concrete. This is the same mechanism as MIC in metallic pipe. Microbes have extremely diverse

modes of metabolism, are natural inhabitants of soil and can survive extreme environments such as the inner wall of geothermal cooling towers [126]. Concrete can also be corroded by acids produced by fermentative bacteria that are natural soil inhabitants [127].

4.3.11.3. Irradiation

Irradiation of concrete can lead to deterioration via a process of aggregate expansion and hydrolysis [111]. At levels encountered by buried concrete piping at nuclear power plants, however, it is unlikely to be a concern.

4.3.11.4. Concrete pipe degradation/failure modes

Failure of PCCP or RCCP pipe is generally due to corrosion of the steel cylinder, prestressing wires or other embedded metal. Corrosion may be initiated from inside or outside the pipe. When steel corrodes, the resulting rust occupies a greater volume than the steel. This expansion creates tensile stresses in the concrete, which can eventually cause cracking, material delamination and spalling. Other impacts can include steel cylinder corrosion leading to pipe leakage, corrosion of rebar which reduces pipe mechanical strength until failure occurs, or breakage of high strength prestressing wires (which is a dominant failure mode of PCCP).

Concrete pipe distress signs include coating cracks and delaminations, corrosion of prestressing wires, broken prestressing wires, longitudinal cracks in the inner core, a hollow sounding inner core, corrosion of steel cylinder or leaks (through joints or steel cylinder). An example of mortar lining degradation is shown in Fig. 63.

Although steel's natural tendency is to undergo corrosion reactions, the alkaline environment of concrete (pH of 12 to 13) provides steel with corrosion protection. At high pH a thin oxide layer forms on the steel and prevents metal atoms from dissolving. This passive film does not actually stop corrosion, but reduces corrosion rates to insignificant levels. For steel in concrete the passive corrosion rate is typically 0.1 µm per year. Without a passive film, steel would corrode at rates at least 1000 times higher [128]. Proper quality concrete and mortar cover are key to maintaining this protection.

Because of concrete's inherent protection, reinforcing steel does not corrode in most concrete elements and structures. However, corrosion can occur when the protective layer is destroyed. This destruction occurs when concrete alkalinity is reduced or when concrete chloride concentration is increased to a certain level. An example of RCCP degradation from inside by chlorides is shown in Fig. 64.



FIG. 63. Steel pipe mortar lining damage (courtesy of Simpson Gumpertz & Heger).



FIG. 64. Degradation of a concrete pressure pipe by chlorides from inside (courtesy of EDF).

The steps of corrosion from the inside by chlorides described in Fig. 64 are:

- (1) Diffusion of the chloride through the inner layer of concrete. The thickness of this layer is designed to prevent chlorides from reaching the steel cylinder during the design life; however, cracking of the inner concrete layer may reduce its effectiveness.
- (2) The chloride reaches the steel cylinder and corrosion may be initiated. Once initiated and if not stopped the corrosion will further develop.
- (3) Over time the corrosion may reach the other side of the steel cylinder (called 'drilling' of the cylinder).
- (4) Once drilled, the degradation of the pipe may continue with corrosion of rebar, spalling or even breaking of the pipe.

As described in Section 4.3.11.2(f), wastewater or sewer applications are susceptible to biogenic sulphide corrosion, which is a bacterially mediated process of forming hydrogen sulphide gas and its subsequent conversion to sulphuric acid which attacks concrete and steel. Corrosion can be minimized by ensuring proper (steeper) gradient sewers to reduce time for hydrogen sulphide generation, providing good ventilation (which can reduce concentrations of hydrogen sulphide gas and may dry exposed sewer crowns) and using acid resistant materials like PVC or vitrified clay pipe as a substitute for concrete or steel sewers.

Corrosion can be increased by the process of carbonation. Carbonation of concrete is a process by which carbon dioxide in ambient air penetrates the concrete and reacts with hydroxides, such as calcium hydroxide, to form carbonates. Carbonation significantly lowers concrete's alkalinity (pH), which is required to protect embedded steel from corrosion. The amount of carbonation is significantly increased in concrete that has a high water to cement ratio, low cement content, short curing period, low strength and highly permeable (porous) paste [121]. Since carbonation is a relatively slow process, sufficient concrete cover over the rebar will prevent the carbonation from reaching it.

Concrete pipe can also degrade or fail for mechanical reasons. Poor construction, improper pipe bedding, settlement, or excessive external loadings can place forces on the pipe that can cause pipe joints or other components to fail. Construction damage to applied coatings can also facilitate premature degradation.

4.3.12. Pipe casing degradation

Metallic pipe casing systems (see Section 4.2.4.3) normally degrade via corrosion, with possible causes being water or soil contact with the pipeline at a holiday combined with a lack of CP, a short between the casing and carrier pipe, humidity or condensation causing atmospheric corrosion on the pipeline or MIC. NACE SP0200 [129] provides guidance on the maintenance of steel-cased pipelines.
4.3.13. Tank degradation

Metallic storage tanks are almost always subject to differential oxygen concentration cells, especially when placed under pavement. Areas of lower oxygen concentration become anodic and corrode with respect to areas of higher concentration (cathode). This can cause severe corrosion attack at tank bottoms, since oxygen concentration is primarily dependent on diffusion from the soil surface.

Beyond the above, USTs are subject to similar ageing mechanisms as above ground tanks, including such things as internal corrosion from the tank product, external environmental corrosion, live roof loads (for tanks with tops exposed to the atmosphere) and ground settlement. Physical damage can also occur from nearby construction activities.

4.3.14. Coating degradation

Protective coatings are used to protect pipes and to mitigate degradation. All coatings degrade over time at rates dependent on their mechanical and environmental service conditions. For example, CTE, commonly used for buried piping, can have a service life ranging from 15 to over 50 years depending on the soil environment. Coating failures can occur due to poor formulation, problems with adhesion, substrate issues, poor application, structure design or exterior forces (chemicals, erosion, abrasion, physical damage or excessive CP current). As well as losing their protective functions, failed internal coatings that peel or flake off can impact on downstream components by fouling or clogging filters or heat exchangers and thus impacting on system availability.

This section presents descriptions of common coating failures and ageing mechanisms.

4.3.14.1. Abrasion or mechanical damage

Abrasion is the mechanical action of rubbing, scraping, scratching, gouging or erosion. It may cause removal of a portion of the coating surface, leaving material unprotected. Exposed external surfaces can be abraded by heavy rain, winds or sand and internal surfaces can be abraded by contained fluids such as slurries. Installation or maintenance activities (by excavation equipment, tooling, etc.) can also result in coating damage. Welding and other heat sources can be particularly damaging. Care should be taken during installation and excavation activities to not damage installed coatings and to repair any damage observed.

In the factory pipes are generally 'holiday tested' to confirm 100% coating coverage. Holiday testing is a simple electrical test where the coated pipe is placed in a conductive solution and the resistance between the uncoated side of the pipe and an electrode in the solution is measured. Gaps or voids in the coating will allow the electrolyte to contact the metal, producing a lower resistance measurement.

4.3.14.2. Adhesion failure (flaking, scaling, peeling, etc.)

Adhesion failure occurs when a coating fails to adhere to its substrate. This may occur if the surface where the coating is applied is not clean. Peeling is quite similar to flaking, although peeling tends to be associated with soft and pliable fresh coatings which can be pulled away from or spontaneously flake away from the substrate or from between coats, due to loss of adhesion. Adhesion failure may be due to improper surface preparation, incompatible coating materials, excessive cure time or improper fabrication.

Flaking occurs on metal surfaces, particularly those that have been galvanized. Alkyds or oil type paints can age and oxidize so that their film shrinks and pulls away from the surface. Scaling is similar to flaking; however, the pieces that break away tend to be much larger (approximately 10 cm in diameter). It is more common on coated, galvanized surfaces or where new coats are applied over old coats with poor surface preparation.

4.3.14.3. Alligatoring

Alligatoring is a form of degradation with very large (macro) crazing/cracking which resembles the skin of an alligator or crocodile. Cracks may penetrate through to the undercoat or down to the substrate. It is caused by internal stresses set up within the coating that cause its surface to shrink more rapidly than the body.

Asphalt and coal tar coatings can be subject to weathering which can cause their surface to harden while the body remains soft. Thick coatings are also more subject to the reaction.

4.3.14.4. Biological attack

Bacteria and fungi can attack biodegradable coatings where the organism can derive energy from the coating material. Oil type coatings, alkyds, polyamide epoxies and coatings with biodegradable plasticizers are most affected. Fungus growth often occurs in shady or damp conditions, with the coating turning grey or green with black splotchy surface areas [130].

Coatings with vinyl chloride acetate resins or chlorinated rubber coatings using non-biodegradable plasticizers have excellent resistance. Attacks can be reduced in oil coatings by the addition of zinc oxide, fungicides, bactericides or all three into the coating formulation.

4.3.14.5. Blistering

Blistering is a form of degradation in which dome-shaped projections or blisters appear in the coating through local loss of adhesion and lifting of the film from the underlying surface (see Figs 65 and 66). Blisters may contain liquid, vapour, gas or crystals.

Many mechanisms can be involved in blistering, including osmotic gradients associated with soluble salts, soluble pigments and corrosion products.

Excessive amounts of CP current can cause coating disbondment (Fig. 67) and blistering. CP reactions on the pipe surfaces locally increase pH levels and can cause small amounts of hydrogen gas to evolve which can cause coating to blister or disbond. Unlike other coating defects, cathodic current does not always mitigate corrosion of blistered areas, which can result in unimpeded local corrosion. The amount of overvoltage needed to generate cathodic disbondment can vary; however, ISO 15589-1 [131] utilizes –1200 mV as a recommended criterion (see Section 7.4.5.4).



FIG. 65. Coating blistering (courtesy of EPRI) [98].



FIG. 66. Coating blister inside a pipe (courtesy of EDF).



FIG. 67. Cathodic disbondment (courtesy of Mears Group).

4.3.14.6. Chalking

Chalking is a form of degradation in which a friable, powdery layer occurs on a coating surface. Changes of colour or fading are also seen. Chalking rates vary with pigment concentration and binder choice, although it is generally a very slow process. Chalking is a known characteristic of certain paints such as epoxy paints. As it is primarily caused by the action of the sun on an organic binder, permanently shaded areas or buried piping generally do not exhibit the phenomenon.

4.3.14.7. Checking and crazing

Checking is a form of degradation in which fine cracks which do not penetrate the topcoat of a coating system appear. Some checking can be so minute that it is impossible to see without magnification. Checking tends to limit coating flexibility and may be due to a poorly formulated coating system.

Crazing is similar to checking but cracks tend to be wider and penetrate deeper in the coating. Fig. 68 shows an example of coating crazing.

ASTM standards D-660 [132] and D-661 [133] provide methods for evaluating the degree of checking and crazing in exterior paints.

4.3.14.8. Chemical attack

Coating dissolution may occur if it is exposed to an aggressive environment and is not designed to withstand such an aggression. Once the coating is dissolved it no longer provides any protective function. Depending on the chemicals and processes involved the dissolved coating may impact on downstream equipment (it may precipitate out or become insoluble under different temperature conditions).

Chemicals such as volatile acids (hydrochloric, nitric, etc.) may also migrate through some coatings and directly corrode the underlying metal.

4.3.14.9. Corrosion associated with coatings (zinc corrosion, undercutting corrosion and pinpoint rusting)

Coatings containing zinc can quickly corrode in strongly acidic environments. Galvanizing tends to fail faster than inorganic zinc coatings as the zinc in organic coatings is partly protected. Alkaline environments with pH values above 10 can also degrade unprotected zinc coatings [130]. Protection is normally via application of topcoats.

Previously exposed steel, or metals such as aluminium or copper, can exhibit corrosion if not properly prepared for coating. Contaminated or very smooth surfaces can be subject to undercutting corrosion, where coating starts at a break, pinhole, holiday or unprotected edge and proceeds under the coating along the metal surface.



FIG. 68. Example of coating crazing (courtesy of EPRI) [98].

Pinpoint rusting occurs when coating thickness is insufficient to protect the substrate. Unprotected areas will be vulnerable to corrosion. See Fig. 69 for an example. Zinc coatings (galvanized, inorganic or organic) normally fail at end of life via this mechanism. As time progresses the pinpoints expand and combine with others until a large continuous area of corrosion is present.

4.3.14.10. Cracking

Cracking results from ageing and weathering and is the splitting of a coating to form visible cracks which may penetrate down to the substrate. Cracking comes in several forms, from minute cracking to severe cracking, leaving the substrate unprotected (Fig. 70). Cracking is generally more dangerous than alligatoring, as it can cause immediate corrosion and chipping or flaking of the coating from the surface.



FIG. 69. Pinpoint rusting.



FIG. 70. Coating cracking (courtesy of EPRI) [98].

4.3.14.11. Delamination

Delamination occurs when a topcoat does not adhere to an undercoat. The topcoat may lie on the surface, blister or peel away. Air reactive coatings needing oxygen or moisture to cure and coatings with internally reactive catalysts or resins can be affected.

Coal tar epoxies are particularly susceptible if they are subjected to rain, condensation or moisture between coating layers.

Avoiding delamination typically involves strict adherence to manufacturer's recommendations for application conditions such as temperature of application and weather, ensuring no contamination between coats and ensuring that coating layers are chemically compatible.

4.3.14.12. Discolouration

Discolouration consists of fading or gradual decreases in coating colour, or changes in coating colour due to ageing, heat, sunlight or chemical attack. In some situations it may resemble chalking but without the powdery surface. Moisture tends to accelerate fading. Coating formulation and selection are typically the only ways to avoid discolouration if colour properties or appearance are important.

4.3.14.13. Holidays, pinholes and uneven application

Holidays are discontinuities in coating films that expose areas of substrate where the intention was to coat the entire area. Coating holidays can be created during the application process; however, most pipe mills pass their pipe through a holiday detector prior to shipping.

Manual or site-applied coatings are subject to holidays and a number of other possible application problems, including pinholes, overspraying, splatter coating, craters, bleeding, lifting, orange peeling, runs and sags.

Pinholes are minute holes in coating films that appear during application and drying. They are small holidays that may not be easily seen. Pinholes are due to air or gas bubbles which burst, giving rise to small craters or holes which fail to coalesce before the film has set. They should be addressed immediately, as subsequent recoating is unlikely to fill the hole.

One cause of pinholing is coating inorganic zinc primers with organic topcoats. During a period shortly after the inorganic zinc coating has been applied, it remains a porous film and solvents from organic topcoats can easily penetrate into the inorganic coating.

Splatter coating occurs when the applicator does not fully overlap coating passes and insufficient coating thickness is applied.

Cratering is the formation of small bowl-shaped depressions at areas of surface contamination, where the coating surface tension is greater than that of the contaminant.

Bleeding is the transfer of a dried colour pigment into a later applied topcoat.

Blushing occurs in lacquers and is the whitening or hazing of a finish due to water absorption during the spraying process.

Lifting happens when topcoat solvents attack a previously applied layer and cause distortions, blisters or wrinkles.

Orange peeling occurs when the spraying technique used causes too much of an orange peel appearance. Runs are coating downward movements caused by excess material flow after the surrounding coating has set. Sags are similar to runs but appear more like a curtain than individual flowing drops. All three of these are generally only cosmetic appearance issues.

4.3.14.14. Mud cracking

Mud cracking is a form of degradation in which a coating looks like a dried-out mud flat. Cracks appear as a network that can vary in size and amount. Usually mud cracking is a result of an over thickness of highly filled coatings.

Mud cracking and alligatoring have similar appearances; however, alligatoring is more of a checking reaction in which a coating surface hardens and shrinks at a much faster rate than the body of the coating itself. Alligatoring may or may not penetrate through the coating surface to the more flexible layer [98].

4.3.14.15. Seawater pitting

Surfaces protected by zinc coatings (inorganic zinc or galvanized coatings) immersed in sea water can develop pits, possibly after 12 to 24 months of seawater exposure. The pits would typically start at sharp edges, abrasions or coating holidays. Seawater salts react with the zinc surface to such an extent that it can no longer provide CP to the steel surface. Protection is normally via the application of resistant topcoats.

Tropical sea water (higher temperatures) yields higher corrosion rates, especially in polluted waters. Tidal zones and fluid agitation are also important considerations in determining the corrosion protection delivered by unprotected galvanized steel. Often, this motion of 'washing' carbonates off the zinc surface and not allowing them to form a protective film, along with zinc erosion, is the cause of base steel corrosion [134].

4.3.14.16. Wrinkling

Wrinkling is the formation of furrows or ridges on a coating surface. It occurs when the surface film expands faster during drying than the paint body. Excessive thickness can aggravate the condition; however, it is typically the result of a coating formulation/selection failure for the application. It is most common with oil based paints or alkyds with driers added to the formulation to increase drying rates. Proper coating formulation for service conditions and careful (thin, even) application is key to minimizing wrinkling.

4.4. STRESSORS AND OPERATING CONDITIONS

Underground piping and tanks are subject to a number of stressors during construction and operation. These include mechanical, chemical, electrochemical (corrosion), electrical (CP currents) and thermal stressors, exposure to UV light (prior to burial) and, in some cases, nuclear radiation.

Understanding stressors is the first step in implementing appropriate mitigating actions.

4.4.1. Mechanical stressors

Underground piping and tanks may be damaged by static, dynamic or cyclic mechanical loads (Fig. 71) or by residual stresses. Sample mechanical stressors include the following (adapted from Ref. [98]):

- Off-normal and unanticipated static loads, including:
 - Roof loads;
 - Wind loads;
 - Snow loads.
- Construction activities:
 - Material lay down areas;
 - Long cable pulls;
 - Heavy surface equipment;
 - Excavation activities.
- Freezing of wet soils.
- Over-torqued bolts.
- Inadequate component support:
 - Loose anchor bolts;
 - Corroded supports;
 - Uneven foundation settlement.
- Unanticipated forces:
 - Inadvertent overpressurization;



FIG. 71. Mechanical stressor (dynamic load) examples: (A) gap between baseplate and wall, (B) gap between baseplate and bolt head (courtesy of EPRI) [98].

- Inappropriate hoist attachments;
- Worker climbing on pipes or conduit.
- Dynamic loads:
 - Fluid transients;
 - Fast-acting valves;
 - Steam bubble collapse water hammer;
 - Other water hammer;
 - Steam hammer;
 - Drop forces;
 - Other impact forces;
 - Gaps in restraints and linkages;
 - Seismic loads.
- Cyclic loads:
 - Cantilevered drain or vent lines that can vibrate.
 - Cavitation damage at flow choke points.
 - Flow-induced vibration:
 - Fluid dynamic;
 - Fluid resonance;
 - Side branch harmonic.
 - Frozen snubbers causing high thermal expansion stresses.
 - On/off cyclic operation.
 - Temperature transients causing thermal expansion cycles.
 - Repetitive maintenance activities.
 - Wear at contact surfaces:
 - Valve seats;
 - Electrical contacts;
 - Loose connections;
 - Sliding supports.
 - Water droplet impingement.

- Residual stresses 'locked in' from original construction and material processing.

4.4.2. Chemical stressors

Chemically aggressive components may damage pipelines or may create a corrosive environment significantly different from the bulk fluid. Sample chemical stressors include:

- Chemically aggressive components:
 - Biocides;
 - Microbiological activity;
 - Caustic/acids;
 - Solvents;
 - Soil constituents;
 - Chemical cleaning compounds;
 - Petroleum products.
- Long term exposure to less chemically aggressive components.
- Inappropriate material applications/installation:
 - Inadequate surface preparation;
 - Cleanliness of pipe surface:
 - Residual salts on piping surfaces.

4.4.3. Electrochemical stressors

Electrochemical stressors induce an electrical current between two connected metal surfaces in the presence of an electrolyte and may induce corrosion. Electrochemical stressors can cause corrosion of metals. Sample electrochemical stressors include [98]:

- Environments inside pipes and tanks;
- Groundwater and soil in contact with buried metals or tank bottoms (which can vary with seasonal water table changes);
- Microbiological activity (common in raw water systems and fuel oil systems);
- Alternating wet/dry conditions;
- Air-to-water interface conditions at tank waterlines;
- Condensation on cold-water pipes;
- Water accumulation or submergence in low areas (Fig. 72);
- Conditions typically present in intake areas.

4.4.4. Electrical stressors

As discussed in Sections 4.3.3.1(e) and 4.3.14.5, electricity is a stressor for piping systems. Stray currents from plant electrical systems, including those installed for CP, can induce corrosion.

4.4.5. Thermal stressors

Temperature may affect degradation of underground piping and tanks. Areas to note include areas of known high or low temperature and areas impacted on by unusual conditions (e.g. steam leaks in area, adjacent heat/cold sources).

4.4.6. Ultraviolet exposure

UV sources include direct sunlight, mercury arc lamps and prolonged corona discharges. Some materials, like plastics, are particularly sensitive to UV exposure. These materials will tend to become weaker and may even break under UV exposure. Although buried piping should not suffer UV exposure following installation, it may be exposed during an excavation or when pipelines go from below to above ground. When exposure duration is important pipe protection may be required.



FIG. 72. Electrochemical stressor example: Horizontal surface near an intake structure exposed to a damp or wet environment acts as a water catch, leading to corrosion (courtesy of EPRI) [98].

4.4.7. Nuclear radiation exposure

Materials, whether metallic or non-metallic, may be damaged due to nuclear radiation exposure near nuclear power plant primary/radioactive systems, spent or irradiated fuel and radioactive waste areas.

IAEA Nuclear Energy Series No. NP-T-3.5 [111] has information regarding radiation impacts on concrete and embedded steel. Effects are only seen at relatively high fluence levels and thus are typically not of concern for buried concrete piping systems.

4.5. SITES OF DEGRADATION

Degradation mechanisms are most likely to proceed in the following conditions:

- High salt exposure (sea water, for instance);
- Stagnant environment (dead leg sections);
- Alternating wet/dry environment;
- Degraded protective coatings;
- Metals in degraded concrete (cracks in RCCP mortar, for instance);
- Dissimilar metal contact;
- Fretting contact;
- Elevated temperature;
- Halogen, sulphate and alkaline exposures.

Hard to reach areas should not be overlooked. Usual areas where degradation may occur are listed as follows:

- Pipeline specific areas:
 - Flexible joints;
 - Terminations;
 - Concrete-to-metal interface areas;

- Dissimilar metal contact, for example, equipment attachment and pipe supports;
- Near positive displacement pumps.
- Pipeline environment:
 - Unintended soil contact locations such as at tank ring walls and pier footings.
 - Areas of known chemical or fuel spillage:
 - Previous spills can leave corrosive residues;
 - Areas under leaking tanks and pipes.
 - Areas where condensation can accumulate.
 - Areas of high humidity.
 - Low lying areas and areas with poor drainage.
 - Areas subject to foreign or external material ingress (e.g. yard drainage systems).
- Operation:
 - Components exposed to raw water;
 - At high fluid velocity locations or flow choke points;
 - In systems that contain entrained particulate;
 - Piping subjected to transient flow or water hammer.
- Visual inspection:
 - Rust, oxide dust deposits, can indicate serious corrosion problems;
 - Depressions on ground surfaces can indicate subsurface erosion.
- Maintenance history:
 - Previous repair work;
 - Unexplained loosening of bolted connections can indicate corrosion, fretting fatigue, or corrosion fatigue;
 - Equipment that has seen a high maintenance frequency;
 - CP systems where impressed current readings provide an indication of changing soil or protective coating condition.

4.6. CONSEQUENCES OF AGEING DEGRADATION AND FAILURES

The consequences of ageing degradation and failures related to underground piping can range from being minor to extremely serious. Depending on the systems affected, pipe or tank failures can have safety related or economic impacts in that they might remove important systems from service or otherwise degrade their function. Unplanned shutdowns or outages may be needed to implement repairs, and compensatory measures may be needed during interim periods. Flood control measures can be compromised.

For systems containing tritium or other radionuclides, leakages into groundwater can generate substantial public or regulator concern even where there are few or no environmental or health impacts. These can require substantial resources to address.

4.7. R&D RESULTS

Access to research and development related to buried and underground piping and tanks is an important part of a nuclear power plant's AMP. Research developments may contradict assumptions made during a plant's design stage and new techniques may be available to investigate and analyse plant systems.

Some research areas currently being investigated include:

- Understanding and forecasting ageing of materials:
 - Long term operation analysis of pipework;
 - Protection against corrosion;
 - Evaluation of degradation for corrosion protective coatings;
 - Reliability assessment of pipelines based on corrosion models.
- Use and application of 'new' materials:
 - Protection of materials against hazards (protecting HDPE against fire, for example);

- Fibre reinforced polymer composites' use and application.
- Welds examination, protection of buried pipework:
 - CP, system application and maintenance;
 - Specific cases of beyond design basis events.
- Non-destructive evaluation (NDE) techniques:
 - Application and range of use of NDE techniques (guided wave technology, for instance);
 - Early detection of leaks in buried piping;
 - Buried pipe direct examination through coatings;
 - Evaluation of indirect assessment techniques for coating flaw detection;
 - NDE approaches for non-metallic piping (e.g. the TestPEP⁵ project in Europe, various work being done by EPRI);
 - Development of new NDE techniques.

- Repair technology:

- Development of new technologies based on fibre reinforced polymer composites;
- Performance of composite repairs.

4.8. OPERATING EXPERIENCE

4.8.1. Relationship to ageing management programme

An effective operating experience (OPEX) review programme is essential to effective ageing management. OPEX should be actively sought from the nuclear industry. This includes sources internal to the operating organization, external operating organizations, plant owner groups, international collaboration programmes (Institute of Nuclear Power Operations (INPO), World Association of Nuclear Operators (WANO), Organisation for Economic Co-operation and Development (OECD), IAEA, etc.), as well as sources external to the nuclear industry (various associations engaged in piping technology and research). Internal company OPEX should be shared externally. Problems in sister plants may point to generic issues that need to be addressed.

Detailed qualitative assessments may be required to evaluate the likely performance of inaccessible components or in response to detecting symptoms of degradation. These assessments benefit considerably from access to a generic database of material performance with age in a given environment. Such databases exist, but often contain proprietary information. With sufficient data and an understanding of the degradation processes involved, generic bounds or models may be derived that can be used in quantitative structural assessments. Sources of data include laboratory tests and experience with both nuclear and non-nuclear structures. Data are often reported in journals and at technical conferences.

Published data typically relate to a single mechanism; in applying this to a plant, care should be taken to understand potential synergies between degradation processes.

Regulators typically require an effective OPEX programme to be in place in the context of normal operation or for lifetime extensions. The US Nuclear Regulatory Commission (USNRC), for example, issued LR-ISG-2011-05 [135], which provides guidelines on how the ongoing review of plant specific and industry wide OPEX should be used to ensure the effectiveness of the licence renewal ageing management programmes used at nuclear power plants. The additional guidelines cover areas where enhancements may need to be made for licence renewal, such as the specific kind of information that should be considered as OPEX, the training of plant personnel, information to consider in OPEX evaluations, criteria for identifying and categorizing OPEX as related to ageing and guidelines for reporting OPEX on age-related degradation to the industry.

4.8.2. Experience related to underground piping

OPEX shows that buried and underground piping and tanks are subject to wall thinning, cracks, corrosion and other degradation. A number of organizations have done work in collecting and evaluating experience related to such systems. Some of this is presented below.

⁵ http://www.testpep.eu/

4.8.2.1. Electric Power Research Institute reported operating experience

EPRI established the Buried Pipe Integrity Group (BPIG) in 2008 as a forum for the exchange of information pertaining to the buried pipe degradation confronting the nuclear industry and as a vehicle for maintaining and modifying the EPRI BPWORKS risk ranking software to meet the needs of the industry. The objectives and services of BPIG include:

- BPIG members will engage in industry dialogue, including on-line tools, to aid in the development of effective buried pipe integrity programmes and in assessing and maintaining existing buried piping systems;
- The BPIG will identify and execute Buried Pipe Reliability Projects (supplementally funded) to address emerging buried pipe issues;
- The BPIG is committed to implementing the Industry Initiative on Buried Pipe Integrity adopted by the Nuclear Energy Institute's (NEI's) Nuclear Strategic Issues Advisory Committee (NSIAC) on 18 November 2009 and its subsequent revisions;
- The BPIG will develop and provide training for buried pipe issues and for the EPRI BPWORKS risk ranking software.

A similarly organized Cathodic Protection Users Group (CPUG) was formed in 2011 with the objectives of:

- Improving the reliability, availability and operational capability of CP systems used in the nuclear power industry;
- Providing a forum for the discussion, development and communication of information on the operation, maintenance and testing of CP systems;
- Providing CPUG members with the opportunity to interface with CP service providers;
- Identifying needed R&D.

The USNRC participates actively in the semiannual EPRI BPIG meetings and the annual EPRI CPUG meetings at which OPEX and technology developments are shared by member organizations. This membership includes the US operating fleet, EDF, and other international members from Canada, Brazil, France, the Republic of Korea and the United Kingdom. EPRI also participates in the NEI Buried Pipe Integrity Task Force which provides regular updates to the USNRC on the status of the industry initiative, OPEX and inspection technology developments. EPRI has developed and maintained an inspection results database (BPIRD or Buried Pipe Inspection Results Database), which as of July 2014 contained approximately 4400 inspection records that represented over 108 000 m of inspected pipe. In 2012, EPRI published a report that compiled the lessons learned on buried and underground piping in nuclear power plants [136].

4.8.2.2. Institute of Nuclear Power Operations reported operating experience

INPO also regularly reports findings from its Equipment Performance and Information Exchange (EPIX) equipment failure database and assessment findings related to buried and underground piping and tank programmes. In a 2013 report [137] it presented the most common areas in which it finds that improvement is needed in operating organization programme implementation. These are:

- Risk ranking review thoroughness;
- Leak extent of condition addressed;
- Leaks occurring and source unknown;
- CP health or none installed;
- Input of results not completed in INPO consolidated events system (small number unacceptable).

Systems most commonly affected by failures were potable water, fire protection, essential service water and sewage. The causes of failures were 'other' internal (21%), general corrosion (19%), cracking (8%), mechanical overload (8%), pitting (5%), flange, seal or joint failure (2%) and galvanic corrosion (1%). The high number of

events categorized as 'other' has traditionally made analysis difficult; however, operating organizations have been improving reporting and these numbers have been in decline.

The majority (68%) of events reported were from 'run-to-failure' systems that received no preventive maintenance or routine inspections. Small numbers of events were reported on safety related piping (9%), piping containing licensed material (6%), or piping containing environmentally sensitive fluids (5%). Pipe events typically increase as plants age.

Operating organizations with good buried and underground piping and tank programmes were seen to:

- Identify failure causes;
- Have a risk ranking challenge board;
- Install CP;
- Have zero leak tolerance especially in piping containing radioactive fluids;
- Have effective station and corporate oversight;
- Have healthy collaboration between underground piping, CP and groundwater monitoring initiatives;
- Effectively use corrective action programmes.

Areas for improvement are increasingly being documented in specific implementation activities as opposed to general issues with lack of programmes, indicating that progress is being made [138].

4.8.2.3. North American water break experience

A study was performed at Utah State University regarding frequencies of water main breaks in Canada and the USA, with results shown in Fig. 73. It reports that cast iron CS piping has the most frequent numbers of failures per installed length. Such studies can help those individuals at nuclear power plants who are responsible for such piping to predict future failures and evaluate risks.

4.8.3. Experience related to cathodic protection systems

In 2005 EPRI produced a report on CP systems [140], including a chapter on CP system OPEX. Approximately one third of the plants responding to a survey reported equipment failures attributed to lack of, or inadequate, CP. The document reviewed the INPO EPIX database for the period 1997 to 2005 for the search terms 'cathodic', 'cathodic protection', 'corrosion' and 'galvanic'. Eight plant equipment records were located documenting corrosion failures due to the lack of, or failure of, CP equipment. The main underground piping event documented



Failures per 160 km / yr

FIG. 73. Failure rate data for buried water main pipes in the USA and Canada, shown by material type (CI – cast iron; DI – ductile iron; CPP – concrete pressure pipe; AC – asbestos cement; other – includes HDPE, galvanized steel and copper) (adapted from Ref. [139]).

was an underground fire protection water main failure that released 4556 L of water and created a hole in the ground approximately 3.7 m long, 2.4 m wide and 1.2 m deep due to erosion. The root causes of the failure were inadequate coating and inadequate CP. System piping and post-indicating valves (PIVs) are buried in direct contact with the soil. The primary protective measure to prevent corrosion of these components is the external coating applied on the pipe and PIVs. The lack of adequate coating applied to the flange bolts of the valve and the lack of any coating to the valve bolting material allowed excessive corrosion to occur. The secondary protective measure to protect the fire protection system piping and PIVs is the CP system. The lack of electrical continuity between the connecting pipe and PIVs resulted in the accelerated corrosion of unprotected bolts and nuts. Actions to prevent reoccurrence included adding details to drawings showing the mechanical bonding connection and correct installation of the insulating kit. They also established preventive tasks to verify continuity at the mechanical bonding connection and the pipe/valve interface.

In the same report, failures of CP system components were studied. Thirty-two records were identified involving failure of CP system components. Eleven failures were ageing related (rectifier, transformer, wiring), eight related to anode depletion, four were design related, three were spurious failures, two were procedure related and one was system drift related.

INPO operating experience reports were also discussed in the report. They document a number of personnel safety issues resulting from leaving a CP system turned on when workers were working on the protected equipment. One of these cases involved a diver. Other experiences documented are cases where CP systems had not functioned for many years, or were conversely providing too much CP current and were damaging equipment.

4.8.4. Experience related to seismic events

Seismic events can result in soil or building settlement and wave passage. These can overstress piping and tank components. Lessons related to underground piping at nuclear power plants have been learned from the impact of some significant seismic events, as follows.

4.8.4.1. Niigata-ken Chuetsu-oki earthquake

At 10.13 a.m. on 16 July 2007, a strong earthquake measuring 6.8 on the Richter scale struck the Chuetsu area in Japan, resulting in shutdown of units 2, 3, 4 and 7 at the Kashiwazaki–Kariwa nuclear power plant, located approximately 9 km from the epicentre. Unit 2 was undergoing startup and Units 1, 5 and 6 were in annual outages when the earthquake occurred [141].

The earthquake damaged fire protection system piping installed outside the Unit 1 reactor combination building. Water leaked from piping, combined with soil and sand and seeped into the composite reactor building through gaps in the piping housing. An approximately 48 cm deep pool of mud and water collected in the fifth basement of the reactor combination building [142].

The earthquake also caused firefighting system pipes buried outside to rupture, thereby inhibiting initial firefighting activities (Fig. 74). A localized failure at a cable penetration allowed water (2000 m³) and soil to enter the reactor building and to flow to lower levels. Some damage to pipes also occurred at the interface with buildings and tanks.

The event led to the installation of some countermeasures at Japanese plants, such as relocating firefighting system pipes buried outside underground to above ground, installing building water feed inlets, welding some pipe joints, strengthening seawater pipe ducts and increasing the use of flexible connections (Fig. 75).

4.8.4.2. Great East Japan Earthquake and Fukushima Daiichi event

The earthquake took place at 2.46 p.m. on 11 March 2011, with the epicentre located approximately 130 km to the east-south-east of Sanriku, Oshika Peninsula (latitude 38.1°N, longitude 142.9°N) [146].

- Scale: moment magnitude $M_{\rm w}$ 9.0;
- Depth of epicentre: 24 km;
- Aftershocks: six with a magnitude of more than M_w 7.0, 93 with a magnitude of more than M_w 6.0 (announcement on 8 September 2011 by the Japan Meteorological Agency);



FIG. 74. Roadway damage and fire protection system failures at Kashiwazaki–Kariwa plant after the Niigata-ken Chuetsu-oki earthquake [143, 144].



FIG. 75. Modifications made at Fukushima Daiichi and Fukushima Daini to improve seismic robustness of fire protection piping: (left) buried pipe relocated above ground; (right) ground strengthening around pipe duct [145].

- Maximum slippage: approximately 30 m;
- Rupture: length approximately 450 km, width approximately 150 km;
- Time of continuous destruction: approximately 170 s.

When the earthquake occurred, units 1, 2 and 3 of the Fukushima Daiichi nuclear power plant were in operation, units 4, 5 and 6 were not in operation and the spent fuel pool in Unit 4 was in a used up condition as its shroud was being replaced.

Damage to Fukushima Daiichi units 1 to 6 was visually checked to the greatest extent possible following the event. Within the scope of the checks, items important to safety and even facilities of low seismic class were almost completely unaffected by earthquake damage.

At the interface between pipes and buildings and tanks, differential settlements were observed but flexible protections were able to withstand the deformation (Fig. 76).

Much fire protection pipe damage is thought to have been caused by the tsunami (Fig. 77) rather than the earthquake. No damage was found on fire protection pipes installed in trenches. This speaks to the effectiveness of the changes made following the earlier event.



FIG. 76. Differential settlement between pipeline and tank/building [147].



FIG. 77. Fire protection pipes removed from support and dislodged (presumed to be tsunami impact) [147].

4.8.5. Experience related to decommissioning

IAEA Technical Report Series No. 439 [148] provides lessons learned from the decommissioning of underground SSCs situated at nuclear facilities. Buried piping that transferred contaminated fluids between buildings or tanks was a common feature at nuclear facilities designed and starting operations from the 1940s to the 1970s. The report indicates that decommissioning activities are directly related to the short and longer term strategy for release of the site: "Usually for release of the site it is absolutely necessary to remove the radiological components (or to demonstrate that what remains achieves regulatory compliance with the release criteria)" ([148], p. 10). Key issues to consider for decommissioning include structural and soil stability, environmental contamination control, connected systems and technology selection for dismantling and demolition.

Typical approaches for decommissioning pipes include first accessing the system for characterization purposes. The pipes may then be cleaned using, for example, high pressure water jetting, followed by trench excavation work and pipe removal. Similar approaches are taken for underground or embedded components. Reference [148] provides several examples of equipment actually used for such purposes.

The most common causes of problems during the decommissioning of underground SSCs were those listed below [148]. The most frequently encountered causes were lack of records, inadequate characterization and lack of timely deactivation of utility services.

- Facility layout Narrow spaces between pipes, no access foreseen for inspections or maintenance, no use of double walled piping or drip pans, etc.;
- Material selection Construction material of piping or tankage exceeding design life and insufficient inspection of its state to verify its continued proper functioning;
- Lack of records Insufficient records available on the exact location and dimensions of embedded parts;
- Unverified records Incorrect interpretation or verification of available information;

- Characterization programmes Insufficient characterization data available;
- Lack of a decommissioning strategy Lack of a clear project strategy for how to reach the final decommissioning end point;
- Waste management Waste disposition routes not defined from the start of the project (including waste conditioning, packaging and storage/disposal);
- Deactivation of utility services Incidents resulting from poor deactivation practices [148].

4.8.6. Specific events

Table 18 presents a summary of selected documented underground piping and tank areas in nuclear power plants. The table is sorted by country, year and plant name.

It is not intended to be a comprehensive list of all events but rather to be illustrative of typical plant events that have occurred in the nuclear industry related to buried and underground piping and tanks.

4.8.7. International generic ageing lessons learned ageing management plans

Under the IAEA's International Generic Ageing Lessons Learned (IGALL) project, proven AMPs for nuclear power plant SSCs have been documented. The IGALL AMPs can be used as a basis for the production of plant specific AMPs. IGALL Working Group 1 (Mechanical Systems) has written AMP 125 [185] on buried and underground piping and tanks. This programme manages ageing of external surfaces through preventive actions and inspection activities. There are no mitigative actions. It manages applicable ageing effects such as loss of material, cracking and changes in material properties. This programme does not address selective leaching. AMP 120, Selective Leaching of Materials [193], is applied in addition to this programme for applicable materials and environments.

Preventive measures under AMP 125 include the use of coatings, CP and component backfill.

Internal surfaces of nuclear power plant piping systems are handled by a variety of other AMPs. AMP 135 [194] consists of inspections of internal surfaces of metallic piping, piping components, ducting, heat exchangers, elastomeric and polymeric components and other components that are exposed to air — indoor uncontrolled, outdoor, condensation and any water system other than open cycle cooling water systems. Others include open cycle cooling water systems (AMP 124 [195]), closed treated water systems (AMP 117 [196]) and fire water systems (AMP 131 [197]).

4.9. INSPECTION/MONITORING/MAINTENANCE HISTORY

A data collection and record keeping system is an important part of an AMP. Sections 4.10 to 4.13 of Ref. [3] provide details regarding typical contents (e.g. failures, malfunctions, maintenance actions and decisions, operating conditions). Inspection, monitoring and maintenance history is a key attribute to be recorded, as this allows (following review and interpretation) degradation to be trended over time, assessment of past degradation (especially corrosion) and remedial actions and prediction of future performance or remaining operating time.

Reference [198] recommends that for piping and tanks protected by CP systems, potential difference and current measurements should be trended to identify changes in the effectiveness of systems and/or coatings and, if ageing of fire mains is managed through monitoring pump activity, that pump activity (or a similar parameter) should also be trended to identify changes that may be a result of increased leakage from buried fire main piping. Where wall thickness measurements are conducted, results should be trended if follow-up examinations are conducted.

4.10. MITIGATION METHODS

It is important to detect ageing related deterioration and mitigate its negative effects before a degraded condition can cause a loss of integrity, interference with operations or failure of the SSCs.

Text cont. on p. 125.

Plant Darlington Canada (2004)			
Darlington Canada (2004)	Problem area	Remedial measure implemented	References
	No isolation flanges installed at standby generator main fuel oil tanks. Non-conductive isolation flanges were meant to electrically isolate anodically protected underground piping from grounded fuel storage tanks but had not been installed. This would tend to degrade the protection offered by the passive sacrificial anodic system against corrosion. This called into question the condition of the estimated 1500 m of underground fuel oil piping at Darlington, which was 20 years old.	Installation of missing isolation flanges, replacement of exhausted anodes and conduction of further inspections to determine how much life remains in the piping	[149]
Darlington Canada (2005)	Tests confirmed there was a pressure boundary failure on underground piping that delivers hydrogen from a hydrogen trailer to the Tritium Removal Facility. Inadequacy of the magnesium galvanic anode CP system was the likely cause of the piping failure. There was no monitoring and maintenance programme in place for the CP system.	Removed hydrogen system from service and roped off the area. Included routine monitoring of anode consumption as part of surveillance programmes. Monitoring and preventive maintenance for CP systems set up. Temporary hydrogen supply line made available for future use.	[149]
Point Lepreau Canada (2008)	In August 2008, a CP probe was damaged on an isolated section of above ground piping which was partially filled with stagnant sea water. The breached probe resulted in a release of chlorine gas. Follow-up investigation concluded that the chlorine gas accumulated in the stagnant section of piping due to reduction of seawater chloride ions from an elevated CP induced potential. Although this incident occurred on an above ground section of pipe, it has relevance to cathodically protected underground piping under similar operating conditions.	Response to CP rectifier alarms revised to prevent reoccurrence	[150]
Cattenom-1 France (1986)	Flooding of basement due to pipe break in underground tunnel carrying service water from river. Supply valve between transfer basin intake and cooling tower basin remained open with normal drain closed. Water overflowed, blocking the plant sewage system, seeping into soil and entering tunnels, because some penetration seals were not leakproof.	None documented	[151]
Nogent France (1993)	Through-wall cracks caused by subsidence between civil structures at Nogent caused EDF to investigate all French nuclear power plants. Similar anomalies found at several plants (Gravelines, Tricastin, Paluel and Nogent). Causes were poor backfill compaction prior to laying pipe and poor construction quality of certain civil structures.	Underground safety piping baselined using video camera inspections and instrumentation installed. Heavy traffic in area prohibited. Provisional repairs made. Preventive maintenance programme developed and permanent repairs made.	[152]

Plant	Problem area	Remedial measure implemented	References
Nuclear power plant not identified France (1998)	Essential service water (ESW) pipe rupture, flooding piping gallery with sea water. Rupture was 1 m \times 3 cm long in a concrete pipe. Prestressing wire and steel cylinder were found to be severely corroded. Condensation had entered a small surface crack.	Extent of condition review found 16 other pipe spools that required replacement EDF developed a maintenance programme for the 6 km of sensitive sea water related piping at EDF plants. The programme included extensive half-cell potential measurements. Pipes were classified into four categories based on urgency to repair, reinforce or replace.	[153–155]
Cattenom-2 France (2004)	Cable fire occurred in penetration. Contributing cause was sealing of penetration at both ends allowing heat buildup and carbonization of insulation. Emphasizes need for proper construction installation of penetrations.		[156, 157]
Blayais-4 France (2011)	Contractor injured while handling scaffolding in pump station well that was designed to allow access to CP anodes	Scaffolding practices reviewed and awareness raised	
Madras-1 India (1984)	Burst in cast iron firefighting system line during functional testing. Check valve failed and no relief valve was provided in design.	Check valve relocated. Need for relief valve reviewed.	[158]
Garigliano Italy (1980)	Heavy rains raised water table, infiltrated into spent resin storage tank rooms and out into external environment	Dewatering pumps and high level alarms installed	[159]
Tsuruga-1 Japan (1981)	Radioactivity released into sea. Leak path included a 10 cm pipe penetration that was not sealed. Wall and floor penetration deficiencies uncovered.	Applicable line permanently isolated	[160]
Tokai-2 Japan (2010)	Thinning of residual heat removal seawater piping caused by corrosion near building penetration. Pipe outer surface was affected. Evidence of rainwater ingress in trench structure and gaps in mortar that was supposed to fill penetration detected. Anchor finish support not properly coated, allowing it to corrode.	Thinned portion of pipe removed and restored. Areas where walk downs not possible added to periodic inspection programme. Changes to inspection protocols implemented. Rainwater intrusion addressed.	[161]
Onagawa-2 Japan (2011)	Loss of function of reactor CCW pumps following Tohoku– Pacific Ocean earthquake and tsunami. Sea water had flowed into the recirculation cooling heat exchanger room and other areas. Damage was found at cable tray and pipe penetrations and other water protective features.	Affected equipment repaired. Paths for seawater entry evaluated. Penetrations repaired and some equipment relocated. Numerous mid and long term countermeasures implemented relating to waterproofing of doors, embankments and tide barriers, etc.	[162]

Plant	Problem area	Remedial measure implemented	References
Tokai-2 Japan (2011)	Release of small quantity of radioactive water due to battery room flooding following Tohoku-Pacific Ocean earthquake and tsunami. Water had flowed back through a drain funnel and flooded the room to a depth of 3 cm. Water was drained using a temporary pump.	Inlet of funnel and sump outlet sealed using steel plate and mortar	[163]
Ohi-2 Japan (2013)	Oil leakage from emergency diesel generator fuel oil piping in trench connecting tank to generator. Poor caulking of rain proofing seal at wall and a gap in trench lid allowed rainwater entry into trench.	Piping replaced and gaps sealed	
Borssele Netherlands (2011)	Degradation of main buried cooling water system BONNA (concrete pressure pipe) pipelines (subsidence, reinforcement corrosion, erosion, concrete cladding damage, small leaks, deformations, cracks) due to ageing and original design and construction deficiencies	Temporary repairs, systematic testing, measurements and on-line monitoring of settlement, groundwater level and pressure initiated. Upgrading and rerouting of cooling lines completed.	[164]
Hanul-1 Republic of Korea (1998)	Shutdown caused by $1.7 \text{ m} \times 7 \text{ cm}$ crack of ESW concrete pipe during testing that flooded essential service water system gallery with sea water	Fine cracks filled with epoxy, painting to prevent corrosion; manhole installed to allow inspection; regular surveillance	[165, 166]
Hanbit-1 Republic of Korea (2013)	Fire water pipe ruptured during excavation causing activation of three fire protection pumps	Flow isolated and pumps shut down. Surveillance and site management of excavation personnel reinforced.	[166]
Cernavoda-1 Romania (2012)	Potential loss of seismic qualification of buried emergency power system piping during excavation. Excavation was being performed to rehabilitate the CP system. It was noted that buried fuel pipes were suspended in mid-air without temporary support. Impact on seismic qualification had not been evaluated.	Work suspended. Temporary supports installed. Applicable project coordination procedures revised.	[167]
Vandellós-2 Spain (2004)	Plant experienced ESW system manhole pipe break that caused plant shutdown. Pipe was a buried BONNA design using steel with concrete on both sides. Manhole had filled with surface water and corroded exposed CS pipe neck (which was unprotected).	Extent of condition review found two other similar cases; all were repaired by installing new pipe or by adding a reinforcing concrete collar around the manhole neck	[153, 154, 168]

Plant	Problem area	Remedial measure implemented	References
Chin Shan-2 Taiwan, China (2004)	Leak in seawater common pipe flooding floor area	Eroded sea water pipe repaired. Pipes added to outage planning schedule for inspections. Review of anticorrosion coating completed.	
South Ukraine-2 Ukraine (1999)	Cables for pumps cut during excavation activities related to replacement of fire protection system underground piping. Excavation activity procedures had not been properly followed.	Replacement programme re-planned; additional training, procedural controls and warning signs put in place	[169]
South Ukraine-2 Ukraine (2003)	ESW train failure in underground weld area. Weld area showed evidence of mechanical treatment (dents). Significant soil watering and subsidence caused additional pipe load and contributed to crack propagation.	Above ground inspections to be done twice per year. Design to obtain more information on inspection techniques.	
Heysham A-1 UK (2003)	Essential cooling water 30 cm cast iron pipe failure during on-line replacement causing turbine basement flooding and two-unit plant shutdown. Safety case for replacement work incorrectly assumed pipe failures would leak before and previously removed piping sections reinforced this incorrect conclusion. Water flow from the pipe break could have caused several workers in the area to be trapped or potentially injured by rising water	British Energy started testing PE piping (HDPE) for safety related seismically qualified systems	
Hartlepool A-1 UK (2005)	High pressure nitrogen pipework discovered with advanced corrosion. Cause was leaking steam trap in trench through which pipe had run.	Pipe repaired. Additional inspections added to maintenance strategy.	
Hartlepool A-1 UK (2006)	Two buried essential cooling water cast iron lines fractured. Water and erosion caused a $4 \text{ m} \times 3 \text{ m} \times 3$ m deep hole which undermined cable trenches. Failure was linked to poor construction (lack of concrete support at face of thrust block where crack originated). Most ESW cast iron lines at the plant had been replaced with coated steel; however, this line had not been done.	Other at-risk sites at plant checked (no similar pipe or thrust block configurations detected). Programme initiated for ground investigation techniques for buried cast iron pipe. Replaced failed pipe.	[170]
Heysham B-2 UK (2006)	Seawater leak at reactor seawater pipework. Possibly due to silt erosion, cleaning practices, reduced chemical dosing or other reasons.	Pipe bypass installed and accessible sections replaced (HDPE used where possible). Inspections performed at leak site. Surveillance programme (site tours) changed.	

Plant	Problem area	Remedial measure implemented	References
Heysham A-1 UK (2009)	Seawater leak observed from cracks in main turbine hall floor. Leak in cast iron pipe had likely been present for some time but had been held back by concrete until it failed. Risk had previously been anticipated but planned contingency actions had not been completed.	Programme to be developed for replacement of all buried 38 and 44 cm cast iron pipework	
Hunterston B-1 UK (2010)	Fire hydrant main weld failure caused by vehicle loading on roadway	Leak repaired using temporary sealing clamp. No loading/ parking signage painted above fire main.	
Palo Verde USA (1982)	Essential cooling water system epoxy lining delamination and peeling. Failures due to excessive film thickness because of hand spraying and capping of pipe prior to full curing of lining.	Elbows were repaired by removing the deficient lining, preparing the surface by grit blasting and recoating	[171]
Dresden USA (1984)	Cathodic system degradation. Investigation of CP system as a follow-up to fire protection pipe failure and several tank leaks found system not functional and had not been maintained.	Numerous actions to address root causes of leakage and CP system lack of functionality	[172]
Limerick USA (1984)	Diesel generator fuel oil storage tank lining failure and incompatibility of fuel oil with tank coating. Coating of fuel oil tank observed to be peeled and flaked. Zinc primer was incompatible with epoxy coating and zinc primer found to react with diesel fuel and could degrade into an insoluble gum in the hot diesel engine. Note: event not specifically buried tank related but shows potential impact of coating systems.	Coating system removed. Suitable coating reapplied to tank bottom areas and sump. Duplex filters installed before engine.	[172]
Oyster Creek USA (1985)	Coal tar coating on inner wall of emergency service water piping peeled off and fouled containment spray system heat exchangers. Attributed to operation of system: system was drained and experienced pronounced thermal cycles that induced cracks in coating. Screen wash nozzles were clogged and allowed debris carryover. Note: event not specifically buried piping related but shows potential impact of coating systems.	Heat exchangers cleaned. Pipe inspected and damage confirmed localized, before being cleaned of damaged coating. Pipe insulated where exposed to outside atmosphere.	[172]
Grand Gulf and Perry USA (1991)	Large amounts of water leaking into the reactor building through electrical conduits. Leak path through yard manholes and connecting electrical conduits was not explicitly considered in the safety analysis.	Conduits sealed	[173]

Plant	Problem area	Remedial measure implemented	References
Beaver Valley USA (1994)	Through-wall leak below grade on emergency diesel river water header due to MIC induced pitting. The river water was not regularly treated with biocide or corrosion inhibitors.		[174]
Numerous plants USA (1999 to 2011)	Numerous cases of submerged electrical cables or water intrusion into conduit documented at US plants (Oyster Creek, Pilgrim, Davis Besse, Brunswick, Beaver Valley-1 and -2, Callaway-1, Fermi-2, Monticello, Peach Bottom-2 and -3, Point Beach-1, TMI-1, Vermont Yankee, Wolf Creek). Various conditions documented, including underground cable vaults or manholes found flooded (often due to inadequate sealing of penetrations), cables not specified for underwater/wet service.	Various remedial measures for cable vaults/manholes, including preventing rainwater incursion, lid gaskets, sealing of lids, repairing drainage systems, fixing penetration seals, etc.	[175–178]
Catawba USA (2000)	Newly installed CP system anodes failed to yield expected output current (600 mV versus 850 mV). Canister design was such that it would degrade over a period of a few months and then provide full current.	Temporarily connected old anodes to circuit to provide additional current until new anode current rose to acceptable levels	[179]
Oyster Creek USA (2001)	Underground portion of emergency service water link leaked during testing. Leak was at a tee to an abandoned branch line. Generic degradation mechanism with salt water CS pipe and coal tar coating.	Affected portion bypassed by 90 m of 36 cm new pipe	[172]
Monticello USA (2002)	Buried station air galvanized piping leakage. Leakage observed via bubbles coming up from ground. Potentially due to pitting or corrosion in wet or moist environment and/or local loading conditions.	Leaking line was replaced by local compressors and was never excavated to determine the root cause	[180]
Wolf Creek USA (2002)	Fire in CP rectifier cabinet caused by vendor wire shorting to ground. Attributed to a manufacturing or shipping problem.	Rectifier repaired. Other similar rectifiers inspected and modified to reduce potential for reoccurrence.	
Brunswick USA (2003)	Fuel oil leak was identified on buried CS piping running from fuel unloading station to main fuel oil storage tank. Cause was external corrosion due to an external coating defect. This would lead to localized corrosion accelerated by salt water permeation because of past service water leak and lack of CP.	Temporary make-up line run, permanent line redesign followed. Fuel oil piping added to underground piping integrity programme. Spill evaluation and a remediation plan developed.	[179]

Plant	Problem area	Remedial measure implemented	References
Prairie Island USA (2003)	Diver received mild shock from CP system while performing underwater inspection of intake structure	CP system to be isolated for future inspections	
Surry-2 USA (2004)	Buried 5 cm auxiliary feedwater pump recirculation pipe failed, causing a 0.5 L/s leak that could not be isolated. Thinning was due to extended overexposure to groundwater with inadequate protective coating.	Line bypassed with new above ground line	[181]
Braidwood USA (2005)	In March 2005, the licensee was notified by a local environmental protection agency of reports of tritium in wells in a nearby community. Licensee began monitoring groundwater between the community and the nuclear power plant and measured levels of tritium in a drainage ditch near the plant access road. Licensee attributed the contamination to historical leakage of vacuum breakers along the circulating water blowdown line that is routinely used for radioactive liquid releases to the Kankakee River. Licensee investigation identified significant unplanned radioactive releases from three of these vacuum breakers during 1996, 1998 and 2000 and other minor releases between 1996 and 2005 entered the groundwater system.	As an immediate corrective action, the licensee suspended all further releases of liquid radioactive material, while a more comprehensive evaluation of the incidents was performed. Licensee evaluated that all doses to public fell below federal regulatory limits.	[172, 182, 183]
Catawba USA (2005)	Oil spill to navigable waters from on-site underground yard drain. Site staff were not aware of oil in the drain. Before yard drain was emptied, rains caused drain to overflow, resulting in oil entry into the lake.	None identified	[179, 184]
Nuclear power plant not identified USA (2005)	In February 2005, a leak was detected in a 10 cm condensate storage supply line. The cause of the leak was MIC or under- deposit corrosion. The leak was repaired in accordance with the national codes and standards.	Leak repaired	[185, 186]
Dresden USA (2005)	In September 2005, a service water leak was discovered in a 1.37 m buried service water header. The header had been in service for 38 years. At the leak location the pipe runs inside a series of concrete vaults, which are filled with sand. Cause of leak was either failure of the external bituminous coating or damage to the coating caused by improper backfill. The pipe had no CP.	A two-unit outage was required to effect repairs. Initial repairs completed by carbon fibre patch. Service water header was relocated above ground.	[172, 185, 186]

Plant	Problem area	Remedial measure implemented	References
Byron USA (2006)	Report of elevated levels of tritium near buried piping		[172, 183, 187]
Catawba USA (2006)	Unexpected backfill conditions found during excavation of buried service water piping. Piping found enveloped in washed crushed stone instead of earth. CP expert indicated that this situation was acceptable since piping condition was excellent.	Backfill plan changed to use washed crushed stone as backfill for this location and to have it available for future locations if encountered. Drawings updated to reflect field conditions.	[179]
Catawba, Seabrook, Surry USA (2006)	Water leakage into buildings or between rooms due to inadequate watertight barriers. Barriers were at electrical conduits, manholes and at floor and construction joints. Leakages were due to inappropriate materials, construction omissions.	Preventive maintenance programmes developed to regularly inspect and repair hydrostatic seals	[88, 179, 188]
Byron USA (2007)	In October 2007, degradation of ESW riser piping at a cooling tower basin was reported. Leak was caused by a loss of pipe wall thickness due to external corrosion induced by wet environment surrounding unprotected CS pipe where it emerged into a vault from an underground run. Corrosion processes that caused this leak affected all eight similar locations on ESW riser pipes within vault enclosures and had occurred over many years.	USNRC completed a special inspection in 2008	[172, 185, 186, 189]
Oyster Creek USA (2008)	Underground portion of service water system developed leak. A 6 to 9 m plume was visible. Line had been scheduled for replacement during a fall outage and pre-outage excavation activities were under way (but not in progress at time of leak). Hole was due to coating degradation and seawater corrosion.	Pipe replacement project completed	[172]
Dresden USA (2009)	In June 2009, an active leak of water containing tritium was discovered from two underground condensate transfer pipes. No member of the public received any exposure from these leaks and no radioactivity from them was detected in any publicly accessible area. Dresden experienced similar leaks in 2004 and 2006 and replaced some underground pipe at that time. Cause of through-wall leaks was determined to be degradation of protective moisture barrier wrap that allowed moisture to come into contact with the piping, resulting in external corrosion.	Initiated voluntary communications with local and state officials as outlined in NEI 07-07 [403]	[172, 185, 186, 190]

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Plant	Problem area	Remedial measure implemented	References
Indian Point USA (2009)	In February 2009, a leak was discovered on the return line to a condensate storage tank. Cause of the leak was coating degradation due to the installation specification not containing restrictions on type of backfill, allowing rocks in the backfill. Leaking piping was also located close to water table.		[185, 186, 191]
Nuclear power plant not identified USA (2009)	In April 2009, a leak was discovered in an aluminium pipe for the condensate transfer system where it went through a concrete wall. Failure was caused by pipe vibration within its steel support system. Vibration led to coating failure and eventual galvanic corrosion between the aluminium pipe and steel supports.		[185, 186]
Oyster Creek USA (2009)	On 15 April 2009, water containing tritium leaked from two non-SR underground condensate transfer pipes at Unit 1. Both pipes were CS pipe; one 20.3 cm (8 in) in diameter and the other 25.4 cm (10 in) in diameter. No member of the public received any exposure from this leak and no radioactivity from it was detected in any publicly accessible area. Leaks developed due to a corrosion mechanism known as anodic dissolution. Poor application of pipe coating left the pipes susceptible to this corrosion.	Initiated voluntary communications with local and state officials as outlined in NEI 07-07. Six additional groundwater monitoring wells added to support characterization of tritium in groundwater.	[172, 182, 190]
Oyster Creek USA (2009)	On 25 August 2009, water containing tritium leaked from an underground condensate transfer pipe at Oyster Creek, Unit 1	Licensee indicated future plans to reposition existing risk significant piping to above ground or more accessible locations to enable enhanced monitoring of pipe conditions	[172, 190, 192]
Peach Bottom USA (2009)	Results of six tritium test wells in the vicinity of the Unit 3 turbine building showed the tritium levels in three wells were > 740Bq/L. The licensee followed the NEI Voluntary Tritium Reporting Initiative in communicating with external stakeholders. There is no information that tritium migrated off-site or affected drinking water sources for site personnel.	Initiated voluntary communications with local and state officials as outlined in NEI 07-07	[172, 190, 192]
LaSalle USA (2010)	Elevated tritium levels around two condensate storage tanks. Leakage was through three small holes in bottom of tank.	Leakage repaired	[172, 192]

Plant	Problem area	Remedial measure implemented	References
Vermont Yankee USA (2010)	Two reported underground piping system leaks which released tritiated water into the environment (January and May). Causes were inadequate construction and housekeeping practices employed when the Advanced Off-Gas Building was constructed in the late 1960s and early 1970s, and when a drain line was added in 1978; and ineffective monitoring and inspection of vulnerable SSCs that eventually leaked radioactive materials into the environment.	Sources identified, pipes repaired, contaminated soil excavated and nearly 1.1 ML of tritium-contaminated groundwater extracted from the site	[182, 192]
Hatch USA (2011)	Elevated tritium outside of condensate storage tank. Source of leak was from condensate transfer line.	Use of transfer piping terminated	[172, 192]
Hatch USA (2011)	25.4 cm (10 in) safety related service water piping found with pinhole leaks during ultrasonic testing (UT). Soft, low alkaline water and high levels of dissolved oxygen provided a corrosive environment.	Temporary repair made with metal plate until full replacement possible. Increased inspections and long range plan implemented.	[172]
Summer-1 USA (2011)	Leak from radioactive liquid waste pipe. Leak had been retained within exterior CS guard pipe until it filled and overflowed a containment structure. Degradation was caused by MIC.	Yoloy piping (see Section 4.2.1.6) replaced with stainless steel with no guard pipe. Additional system changes and leak detection added. Additional borescope inspection of similar piping.	[1]
Wolf Creek-1 USA (2012)	Poor backfill installation related to grounding cable installation impacted on emergency service water piping (requisite amount of backfill for ESW piping removed). Both ESW trains were deemed inoperable.	Site ground penetration permit/excavation procedures reviewed. Gap analysis of fast-track modification processes performed.	
Oconee-1 USA (2012)	Pits discovered (some through wall) on buried diesel fuel oil storage tank. Most likely cause was MIC. No detectable leaks to ground were noted.	Changed regular inspection intervals. Review of chemistry control of tank oil (perhaps including addition of a biocide).	[179]
St. Lucie USA (2014)	Blockage in the site's storm drain system caused water to back up within the emergency core cooling system pipe tunnel. Water entered the reactor auxiliary bay through two degraded conduits that lacked internal flood barriers. Four additional conduits discovered during extent of condition review.	Installing qualified internal water seals on all affected conduits	[68]

As described in Section 2, effective AMPs should include mitigating methods for the effects of ageing degradation mechanisms. Mitigating strategies include actions such as changes to operations; maintenance, repair and replacement to minimize and control detected ageing effects; and/or degradation of the structure or component.

As per Ref. [3], recommended methods to mitigate the effects of ageing mechanisms include:

- Maintenance methods and practices, condition monitoring (including refurbishment and periodic replacement of parts and consumables) to control ageing degradation of the structure/component;
- Operating conditions and practices that minimize the rate of ageing degradation of the structure/component;
- Possible changes in design and materials of the component to control ageing degradation of the structure/ component.

For underground piping systems, mitigation strategies usually consist of applying protective measures, such as coatings and CP. Measures can also be taken to mitigate the effects of stray currents. Each of these is described in the following sections.

Operating strategies (flow velocities, avoiding dead legs, etc.) and chemistry regimes (pH, levels of biocides, etc.) can be adjusted to assist with degradation mitigation. These will be discussed in more detail in Section 6. When repairs are made (Section 8), there is an opportunity to select more appropriate materials and joining methods, taking into account pipeline loadings and the external environment.

4.10.1. Cathodic protection systems

CP can be applied to steel and other metals that are immersed in an electrolyte (soil or water). It can be used to minimize or eliminate all forms of corrosion, is recommended for buried steel pipelines and tanks and can extensively reduce life cycle costs of the protected equipment.

CP is based on the decrease of corrosion potential by application of a current (either externally impressed or deliberately derived from dissimilar metals). Protection is achieved when the potential of local cathodes is electrically polarized to be more negative than the local anodes. The system should be operated so that CP criteria are met at every location in the system.

CP is normally applied in accordance with a consensus standard recognized by national authorities. European standard EN 12954 [44], for example, has sample guidelines on specific requirements for buried or immersed metallic structures.

There are three methods of applying the required electrical current: sacrificial anode systems, impressed current systems and combination or hybrid systems.

4.10.1.1. Sacrificial anode cathodic protection

Sacrificial anode (SACP) or galvanic CP systems are those in which protective current is provided by a metal of more electronegative corrosion potential than the protected item.

Such systems can provide protection to small areas due to their limited current capabilities. Anodes are typically zinc, magnesium or aluminium (Fig. 78) and are generally limited to soil resistivities of less than 50 000 Ω cm [12]. Sacrificial anodes in buried applications are typically magnesium or zinc. Aluminium is not



FIG. 78. Zinc, aluminium and magnesium sacrificial anodes and graphite and mixed metal oxide impressed current anodes (courtesy of Corrpro Companies Inc.).

practical for buried installations (because of problems associated with keeping it electrically active with good efficiency), but is commonly used in specialized marine applications.

External power sources are not required for sacrificial anodes. Anodes are directly connected to pipe (typically through a test post) and buried relatively close (usually less than 3 m) to the structure at depths at least equal to the structure (Fig. 79). Typical designs allow for 10–15 year service lives of installed anodes before replacement is necessary. The systems may be used on a temporary basis for new or existing pipelines until a powered impressed current becomes available.

Both horizontal and vertical installation of galvanic anodes is possible; however, vertical beds are generally preferred. Test posts allow for monitoring levels of CP and anode effectiveness. If anodes are connected directly without a test post it becomes impossible to take effective measurements.

In some applications mixed metal oxide (MMO) coated titanium wire or ribbon form can be buried in trenches during construction and run adjacent to the pipeline for its entire length. Sometimes two wires opposite from each other are required to prevent shielding [199].

Using specially prepared anode backfill can help to stabilize anode potential, prevent anode polarization, lower anode to earth resistance (increasing current output) and improve efficiency by reducing anode self-corrosion [200].

4.10.1.2. Impressed current cathodic protection

Impressed current cathodic protection (ICCP) systems utilize direct current (normally produced from AC by a transformer rectifier) in conjunction with relatively inert anodes such as graphite, thin coatings of platinum or activated MMOs on metals such as titanium, niobium, lead alloys or silicon-iron (Fig. 78). Such materials have lower consumption rates than those used in typical SACP anodes. In some cases a consumable anode such as scrap iron or steel is used. Such systems are typically not limited by structure size or soil resistivity. Anodes are available in many configurations, including rods, discs, meshes or ribbons.

ICCP systems utilize an outside power supply (rectifier) to control voltage between the buried component and an anode in such a manner that the pipe becomes the cathode in the circuit and corrosion is mitigated.

Equipment required includes an external power source, a transformer to step down incoming AC power, a rectifier to convert AC into DC and a control circuit to adjust current provided to the structure (Fig. 80). If AC power is not available, solar power, thermo-electric generators, diesel generators or windmills may be used.

Many anodes are typically required to provide desired design life and are buried some distance from the structure in an 'anode bed'. Anode beds can be installed in many configurations, including shallow or linear arrangements



FIG. 79. Sacrificial anode cathodic protection system (courtesy of Cathodic Protection Co. Ltd) [199].



FIG. 80. Typical impressed current cathodic protection rectifier [201].

or in deep beds that can be 30 m deep or more. Deep beds accommodate congested areas where shallower beds may interfere with other structures, or pipes may be shielded from the anodes by other buried equipment. Deep installations need to consider any groundwater or aquifer impacts as part of their design, for example, by ensuring surface contaminants do not enter groundwater via any installed anode wells. NACE SP0572 [202] provides more detail regarding these deep bed systems. Linear anodes are long assemblies used extensively for new construction, since they can be readily installed in the same trench as the protected pipe [16].

Special carbonaceous backfills can be utilized to reduce anode consumption and circuit resistance. Such backfills bear most of the consumption resulting from current discharge.

In dry climates anode 'dry out' can be an issue. Anode dry out occurs when chemical reactions at the anode–soil interface result in the consumption of water through electrolysis that is not sufficiently replaced by groundwater. The condition can be addressed by an artificial water supply or by reducing CP rectifier current until equilibrium is reached.

In addition to the rectifier and anodes, electrical connections from the rectifier to the pipe and the anode bed are required (Fig. 81). Correct polarity is essential to such connections to ensure that it is the anodes that corrode as opposed to the pipeline structure.

In addition to the equipment providing protection, post mounted, wall mounted or flush-to-grade test stations are needed to monitor CP system effectiveness. Sufficient locations are required to provide a representative sample of pipe-to-soil potentials that are used to gauge CP system performance. Such stations use 'permanent' reference electrodes (typically copper sulphate; see NACE TM0211 [203]), voltage drop free coupons and/or corrosion rate (electrical resistance) probes at or near the pipe depth to assess the CP system.

Coupon test stations manufactured of the same material as the protected pipe are often installed at pipe crossings, where copper grounding grids are nearby, where pipe enters a concrete building wall and where testing indicates higher current drain from the CP system. These can provide independent data on corrosion rates and CP system performance. NACE SP0104 [301] (formerly RP0104 [204]) provides guidance in using such coupons with CP systems.

Isolating devices may be used in congested areas to isolate pipework to be cathodically protected from the ground grid and any other piping systems. They can thus reduce the amount of current needed as well as electrical hazards for personnel. Types of devices may include insulating couplings or DC decoupling devices. The DC devices only block DC current flow while still allowing AC currents and lightning to pass through to the ground. The use of isolating devices in areas where piping is congested may result in stray current corrosion. NACE SP0286 [205] provides guidance regarding the use of insulating devices for cathodically protected pipelines [16].



FIG. 81. Impressed current cathodic protection system.

4.10.1.3. Pulse cathodic protection systems

Pulse CP is a special application of ICCP systems that gives out short DC impulses to underwater or underground metal structures. It has been used extensively in the oil and gas industry for well casing protection and early water applications dating back to the 1970s. As a rule, voltage is provided for 10% of the time and so the influence of neighbouring metal structures is lowered when compared to traditional CP. Typical pulse frequencies are in the range of 1000 to 10 000 Hz [59].

High-ampere current impulses flow on the metal structure, which gives it a significant charge. Free electrons quickly spread the charge along all metal surfaces. The metal structure has its own induction, which limits the speed of charge movement. Charge in the metal structure, even for complex configurations, is distributed, so that the vector of the intensity of the electric field is perpendicular to the metal surface. In places where coatings are damaged, electric current leakage may occur. This causes protective electrochemical reactions on the border of the metal-electrolyte transition. In longitudinal objects, e.g. pipelines, the phenomenon of self-induction 'pushes' the charge further away, providing the best protection to more remote areas. Therefore, the application of pulse CP systems can lead to more uniform structure protection and widen the protected area.

It is possible to select pulse current parameters at which O_2-H_2 water dissociation occurs and then recombines after interruption of the current pulse. This reduces H_2 formation and the probability of coating damage and other damage due to hydrogen stress cracking.

Sample pulse CP systems developed by the Orgenergogaz and GeoLineGroup companies in the Russian Federation are shown in Fig. 82 and have technical parameters described in Table 19.

Pulse CP operates as follows: the electrical field impulses force positive ions to move towards sites of the pipeline with damaged covering, and negative ions (which cause corrosion) to move towards the anodic ground electrode. A layer with a low concentration of negative ions will form near areas of damaged covering. After the impulse stops, negative ions from areas of high concentration diffuse back towards the pipe; however, this process is much slower than the movement of ions in the electric field. Therefore, the pause duration can be set to be longer than the impulse duration (e.g. $10 \times$ longer), economizing on the consumed electric power. The next impulse is given before the concentration of the negative ions near the pipe has risen up to a certain appreciable low level.

During ICCP hydrogen ions penetrate partially inside the pipe material. They make a complex combination with iron ions, which form a crystal lattice, and with impurities partially turn into hydrogen molecules which mainly release into the atmosphere. Then a small amount of molecular hydrogen diffuses into the pipe material which gradually makes it brittle.



FIG. 82. Pulse cathodic protection (CP) systems: (left) pulse CP station powered by electric line; (right) pulse CP station powered by autonomous electricity source (courtesy of Rosenergoatom).

Technical parameters	Powered by electric line ~220 V	Powered by gas energy
Output voltage (V)	24	24
Pulse current (A)	Up to 80	Up to 35
Duration of impulse (s)	0.8–1.2	0.8–1.2
Duration of pause (s)	4.5–14.5	4.5–14.5
Consumption of power (Wt)	500	90
Overall dimensions (mm)	$430\times180\times350$	$870 \times 550 \times 450$
Weight (kg)	10	85
Service life (years)	10	10

TABLE 19. SAMPLE PULSE CP SYSTEM PARAMETERS

Those processes become much less intensive during pulse CP. According to Faraday's first law of electrolysis, the mass of evaluated hydrogen is directly proportional to the quantity of electricity transferred through an electrolyte. During pulse CP, the quantity of electricity is many times less. The recombination process reduces the concentration of hydrogen near the pipe surface even more. Therefore, there should be no hydrogen absorption in pipelines by pulse CP, or it should occur much more slowly in comparison with ICCP systems.

Figure 83 illustrates a surface area of electrodes made from thermo-expanded graphite (external sides), which were situated in electrochemical cells under action by impulse and DC currents. The photo on the right distinctly shows surface swelling, indicating gas release inside of the electrode under DC action. The electrode removed from the electrochemical cell through which the impulse current was passed did not indicate any swelling. This experiment shows that gas release is much lower under pulse current CP than under ICCP.

Pulse CP systems can thus potentially (when compared to traditional ICCP) be smaller and more efficient (in terms of power savings, increased electrode life and fewer repairs), and provide better protection.



FIG. 83. Thermo-expanded graphite electrodes: (left) after action by pulse current; (right) after action by DC (courtesy of Rosenergoatom).

4.10.1.4. Hybrid systems and cathodic protection comparison

Hybrid systems consist of a mixture of sacrificial anodes and externally powered impressed current anodes. Sacrificial anodes provide protection when the ICCP system is shut down for inspection and maintenance, or at difficult areas called 'hot spots'.

In most cases, ICCP systems are designed to deliver relatively large currents from a limited number of anodes, while SACP systems are designed to deliver relatively small currents from a larger number of anodes. At nuclear power plants, because piping is connected to the copper grounding grid, most CP current will flow to other structures. Thus current requirements will be large and the ICCP method is almost always used. Unless the anodes are used for 'hot spot' protection, the SACP method of protection should only be used for coated and electrically isolated pipes. Table 20 provides a comparison of the two methods.

4.10.1.5. Buried tank cathodic protection

External surfaces of buried tanks can be protected by SACP or ICCP systems. Blanket systems that protect multiple tanks can also be installed. Isolation from other metallic structures, including grounding systems, is often necessary. The large ground grids typical at nuclear power plants make the current levels required for CP of underground tanks significantly higher than those required to protect isolated systems. ICCP systems are thus more typically used at nuclear power plants.

Tanks that contain water or a water phase (e.g. oil or petrochemical tanks with an aqueous phase) can be protected by internal CP. Water tanks can be protected by SACP or ICCP (depending on electrolyte resistivity) and oil tanks by SACP. SACP systems typically have anodes welded or bolted directly to the structure, while ICCP systems have anodes suspended from the roof, drilled through the tank walls or suspended from eyelets mounted in the tank [199]. Biocides may be added to fuel oil to reduce potential MIC.

ICCP anode cable tails need to be routed back to the power source, normally located in a non-hazardous area. In particular, for ICCP systems it is recommended that permanently installed monitoring systems be installed to ensure adequate levels of protection.

Factory-fabricated and field installed SACP and ICCP systems are available for new USTs. SACP systems for new USTs consist of coatings with high dielectrical qualities, electrically isolated fittings and sacrificial anodes. Pre-engineered USTs are increasingly available with CP already incorporated (see Fig. 15 in Section 4.2.5).

TABLE 20. COMPARISON OF CP CHARACTERISTICS [206]

Sacrificial anode system	Impressed current system
No external power required	External power source required
Simple design	More complex design
Fixed driving voltage	Adjustable driving voltage
Limited current (10–50 mA typical)	Larger current (10–100 A typical)
Typically used with electrically isolated, well coated structures	May be used with electrically isolated structures and grounded structures that are coated or bare
Typically used in soils with lower resistivity	May be used in low resistivity or high resistivity soils
Lower maintenance	Higher maintenance
Does not cause stray current corrosion	Stray current corrosion can be generated on isolated structures that are in close proximity to the anode ground bed

Guidelines regarding the design, installation and testing of CP systems for USTs and piping can be found in API RP 1632 [207], NACE SP0169 [208], NACE SP0285 [209], STI R892 [210], STI R051 [211], STI R972 [212] and in [213]. An assessment guide for determining the suitability of a buried steel tank to be upgraded with CP is available from ASTM [214].

4.10.1.6. Concrete pipe cathodic protection

CP can be effectively applied to PCCP if electrical continuity is established along the line. Electrical continuity is accomplished by a combination of small gauge shorting straps installed under the prestressing wire prior to wrapping and by installing bonding jumpers across each pipe joint as the pipe is installed. Bonding jumpers are connected to steel components of each pipe length. ICCP systems should be used with caution when providing CP for prestressed concrete pipe due to the possibility of overprotection. Overprotection of the prestressing wires may cause hydrogen embrittlement, leading to their failure. SACP cathodic protection systems can be used to minimize this potential for embrittlement.

NACE has prepared a specific guide, RP0100 for CP of PCCP pipe [215], which can be referred to for more detail.

4.10.2. Coating application

(a) General considerations

Coatings can be applied for 'best practice' corrosion protection of equipment, or to mitigate observed degradation. For less demanding applications, simpler and more cost effective solutions may be adopted. Justification should be provided when coatings are not used. A description of coating materials is provided in Section 4.2.6.

It is recommended that a procedure is followed to achieve effective corrosion protection, as detailed below, based on guidelines given in Annex A of ISO 12944-1 [216].

- (i) Analyse or estimate environment corrosivity in area of structure;
- (ii) Establish any special conditions which may affect choice of coating;

- (iii) Examine structure design and ensure adverse design features have been avoided and adequate access has been provided for corrosion protection work. Where practicable, avoid galvanic corrosion by insulating dissimilar metals from each other;
- (iv) For maintenance refurbishment, assess condition of surface to be treated. Guidelines on condition assessment are provided in Ref. [216];
- (v) Determine required durability of protective coating and select a suitable system;
- (vi) Arrange for health and safety risks and environmental impacts to be minimized as far as practicable;
- (vii) Select method of application and produce a plan of work;
- (viii) Establish inspection and test plan to be carried out during and after work;
- (ix) Establish inspection and maintenance programme for service life of structure.

External corrosion is most effectively mitigated when coatings work together with CP. In this dual approach to external corrosion control, the function of the coating is to provide a barrier between the structure and its environment and act as a tightly bonded film to prevent flow of stray current onto the pipe. This limits the number of places in which corrosion can occur and significantly reduces the amount of CP current required to mitigate corrosion.

(b) Coating selection

Most external corrosion related problems are due to improperly selected or applied coatings. Understanding the conditions that a coating will be exposed to and matching those to coating properties and capabilities will enhance safety and integrity, and save money over the long term.

The performance of any particular coating system is directly related to the conditions encountered during the application, installation and maintenance of the structure. Therefore, before any coating selection is initiated, it is imperative that operating, environmental and construction conditions are well understood. Future need and ability to repair or refurbish a coating should also be considered, as some systems can be difficult to remove.

Proper coating selection is critical to ensuring long term integrity. Coatings are normally selected based on environmental conditions in accordance with a consensus standard recognized by the national authorities. Errors in selection may lead to pipe failure. The cost of corrosion failure and remedial coating work can far exceed the extra cost of properly selected high integrity coatings.

Normally, straight pipe is factory coated/lined, which ensures higher quality than is possible in the field. Factory applied coatings are usually FBE, multilayer PE, coal tar epoxy, polyurethane, single and three-layer tape, cement mortar, asphalt and CTE, or PVC tape.

Pipe operating temperature is key in selecting a coating or lining system. Many coating systems are limited by a maximum temperature at which they will degrade and eventually fail. Likewise, some coatings offer better protection at low temperatures than others. Manufacturers recommend temperature ranges suited for their product; however, such recommendations should be verified by testing to assess properties at expected operating temperatures.

In external coating, backfill and terrain characteristics should be considered when selecting a coating. Rocky or frozen backfill requires coatings with good impact and penetration resistance. Clay soil requires coatings with excellent soil stress resistance. If a pipe is to be bent during construction, a coating with flexibility sufficient for field bending is required. Wet environments require coatings with excellent water resistance, high adhesion characteristics and minimal cathodic disbondment.

Environmental conditions have a significant role in coating and lining selection and the development of application procedures. The following environmental conditions are important to consider: ambient temperature range (high and low), dew point range, humidity range, protection from precipitation and exposure to sunlight. Good adhesion to the pipe surface, not just at ambient temperatures but at the maximum operating temperature of the pipe, is a critical consideration. Environmental conditions can often be altered by air-conditioning, preheating, post-heating and hoarding with tents or other suitable temporary enclosures. Coating selection is often based on test results on new samples and not on environmentally aged coatings, which can give overly optimistic results.

Coatings are used to provide corrosion protection for piping materials, by providing a barrier between environment and metal. Sometimes coatings can permit material use that would otherwise not have been possible because it would have had a very short life in direct contact with the environment. Corrosion can start at areas of
coating failure. In some cases, such as coated CS exposed to sea water, corrosion can proceed rapidly. Coating failure can also contribute to system damage, for example, via flow blockage of pipe or heat exchangers.

4.10.3. Stray current mitigation

In implementing countermeasures against stray current effects, the nature of stray currents has to be considered. For mitigating DC interference (most common), the following steps can be taken:

- Removing stray current source or reduce its output current;
- Providing electrical bonding (e.g. a metallic conductor return path to the negative side of the interfering source);
- Installing cathodic shielding;
- Installing sacrificial anodes;
- Applying coatings to current pick-up areas.

Some of these are illustrated in Fig. 84. Figure 85 illustrates coating application to help address stray currents. AC current mitigation is similar. If the induced AC and any other sources of AC on the pipeline can be removed then the pipeline will no longer be at risk from AC corrosion. When the induced AC cannot be removed, a calculation can be performed to determine the minimum level of AC voltage at which AC corrosion will occur [217]:

 $I_{\rm ac} = 8V_{\rm ac}/\rho\pi d$

where

 I_{ac} = AC current density (amps/m²);

- V_{ac} = pipe AC voltage to remote earth (volts AC);
- ρ = soil resistivity ($\Omega \cdot m$);
- π = 3.14159;
- d = defect diameter of a circular defect with an area of 1 cm².



FIG. 84. Methods to address stray currents.



FIG. 85. Coating application to help address stray currents (courtesy of Ontario Power Generation).

Once this minimum voltage has been calculated then suitable AC mitigation measures can be designed and installed to ensure that the levels of induced AC do not exceed this level. This can often be significantly lower than levels set for safety reasons. Mitigation can take the form of either zinc ribbon anodes installed in the same trench as the pipeline or bare copper cable/tape. If the induced AC voltage and current density figures stay below the criteria discussed above then the mitigation can be considered to be successful. However, they should be monitored routinely throughout the life of the pipeline to ensure that any changes that might result in the pipeline being at risk again from AC corrosion are identified and corrected.

Inadmissible step and touch voltages are often mitigated via installing additional grounding, installing local ground mats where people work, or installing cancelling wires running parallel to a pipeline.

4.11. CURRENT STATUS, CONDITION INDICATORS

Knowledge of the current status of underground piping and tanks is essential for nuclear power plants. This is typically via assessments against documented condition indicators. Condition indicators can be established for detecting, monitoring and trending ageing degradation of applicable structures. Some underground piping condition indicators include pipe wall thickness measurements, soil to pipe potentials, CP currents and anode wastage, events related to pipe leaks or blockages, etc.

Most buried piping programmes initially begin, due to the difficulties of digging, with little actual knowledge of field conditions. A limited number of direct inspections do not always provide full knowledge of the condition of the complete system. Caution should thus be applied to avoid a false sense of security related to a plant's buried piping condition. Section 5 details how to set up a programme where one has not previously existed.

4.12. DESIGN IMPLICATIONS

Piping and tanks are laid out following the rules of national design and construction codes, standards and guides. Some examples of these are Refs [50, 218–225]. These codes and standards rely on equations that include safety margins that will allow the pipe or tank to operate properly during its design life. To achieve a proper design,

loadings and degradation mechanisms have to be correctly taken into account during the design. An error or a miscalculation in the design may affect the lifetime of a pipeline and may lead to unplanned shutdown and outage.

Inspection and maintenance issues also have to be taken into account in the design, especially for buried pipes. Unlike an underground pipe, which is underground but within another structure, a buried pipe is harder to inspect and sometimes excavations are required to inspect the outer layer of the pipe. These excavations are costly and time-consuming and may damage the pipe if not properly done. Thus the designer should consider whether the pipe should be buried or underground.

Reference [148] provides some design recommendations based on experience with underground piping decommissioning. It states that:

"It is advisable that piping be routed above ground as far as possible and practical. If necessary, it is important that piping routed below ground be 'doubly contained' (e.g. in waterproof trenches with sumps and inspection facilities) to prevent subsoil contamination in the event of pipe leakage. Proper sloping of trench flooring would ensure passive drainage of any leakage to sumps. Failure of unlined sumps and trenches could also lead to seepage of radioactivity to the subsoil" ([148], p. 7).

When buried piping is the best solution, its protection should be designed with the utmost care and designers should incorporate mechanisms to allow for its easy inspection (e.g. access ports, instrumentation, pre-installed guided wave collars).

There are different approaches to the issue of corrosion prevention in nuclear power plants. However, in practice, the principles that apply are similar irrespective of whether the SSCs are located above or below ground. With regard to buried piping and tanks the following should be considered during design to enable a cost effective technical solution to be implemented:

- Material selection;
- Control of fluid chemistry;
- Selection and application of internal and/or external protective coatings (if applicable);
- CP (if applicable).

Where metallic components are adopted for buried applications it is essential that consideration of the corrosive effects of the soil is included during design.

Design and selection of the pipe material must account for suspected degradation mechanisms of the pipe, so as to reduce their influence. Increasingly HDPE piping is being used for new installations or system replacements due to its superior performance (e.g. corrosion resistance and lack of fouling) and cost characteristics, and other non-metallic piping such as PVC is being used for shorter repairs of failed metallic pipe sections. However, this is not always a practical option and a metallic structure with a protective coating is often installed. There are numerous metallic material options but the most cost effective solutions are generally CS, ductile iron or reinforced concrete. Metallic materials will need to be protected from the surrounding buried environment if a reasonable design life is to be obtained. Using corrosion resistant metals such as super duplex or titanium is judged not to be commercially viable for this type of environment.

External coating application (see Section 4.10.2) is the primary form of corrosion prevention for metallic components used in buried applications. Coatings provide a barrier between the soil and metallic substrate, thus ensuring that the electrolytic cell required to promote corrosion and degradation cannot be initiated. Using barrier coatings permits the use of base materials which are less expensive in corrosive environments. As long as the barrier coating remains intact, corrosion is effectively nullified. However, metallic substrate corrosion is inevitable if environmental conditions are conducive and the coating is breached or begins to degrade.

It should be noted that all barrier coatings exhibit some permeability and therefore cannot be claimed to be 100% effective in preventing moisture from reaching the metallic substrate. However, if properly selected, applied and installed they can provide many years of excellent protection against degradation. All coatings will degrade with time and if they are subjected to operating regimes outside their design basis this degradation can be accelerated. Life expectancy of a barrier coating used in a typical buried application should be in excess of 20 years. However, this is variable as product quality and its application in conjunction with the care taken during installation will have a significant effect on the actual achieved life.

Where barrier coatings are adopted in conjunction with CP care must be exercised to ensure that cathodic disbondment is not initiated due to excessive current being applied to the buried piping or tank (see Section 7.4.5.3(b)(vii)). CP equipment requires careful design and, once installed, requires regular surveillance and maintenance to ensure that it provides ongoing protection and a long and reliable operating life.

4.13. CONSTRUCTION IMPLICATIONS

Construction activities are important in that they are crucial to the long term performance of new buried and underground piping and tanks, can damage or otherwise impact on existing components and can pose industrial safety risks to personnel.

Operating organizations (per para. 3.11 of Ref. [3]) need to ensure that "current knowledge about relevant ageing mechanisms and effects and degradation and possible mitigation measures are taken into account in fabrication and construction of SSCs". This requires good communication between the ageing management responsible individual in the operating organization and the construction organization.

During installation it is important to ensure that the piping arrangement is installed as per the design. Other items to note include the need for proper inspection of material upon delivery, proper storage and handling and proper installation and assembly. As part of installation, welding and joining controls should be in effect (welding/joining programme documented, including requirements for personnel qualifications, material control and welding/joining procedures), the laying bed should be checked to ensure settlement, pipe levels and slopes should be as defined in design drawings, proper backfilling procedures should be followed and the entire system should be leak tested. Proper backfill material and compaction is essential to the operation of CP systems.

Of particular importance is ensuring that field coatings are applied properly. Coatings can be susceptible to damage during construction and thus coating inspections are very important to long term durability. Such inspections, which can account for 10% of coating installation costs, ensure that all specifications are met, any damage has been repaired, proper tests have been performed and records are kept.

When performing construction inspections it is beneficial to complete and record baseline inspections in the same manner as will be done later as part of the buried and underground piping and tank AMP. This will allow any initial fabrication and construction flaws to be detected. Such flaws, which to varying degrees are present in all piping and tanks (since they may be smaller than sizes allowed by construction codes or otherwise missed), are important to fitness-for-service assessment. They can later grow in service or aggravate a service-induced flaw and if detected later could be confused with degradation-induced flaws [226].

Construction activities near buried or underground structures can change local soil compaction and cause significant stresses on piping and tanks. Heavy surface loads can also cause large stresses in piping and tanks that are buried at relatively shallow depths. Programmes should be in place to review and control significant construction loads (see Section 6.3.3).

Excavation activities pose a special risk to construction personnel. These are covered in Section 8.2.1.2. New 'no-dig' construction techniques such as microtunnelling and in situ liner repair methods can reduce both costs and exposure of personnel to the hazards of working in trenches.

5. DEVELOPING AND OPTIMIZING ACTIVITIES FOR AGEING MANAGEMENT OF UNDERGROUND PIPING AND TANKS

5.1. BACKGROUND

Underground structures (e.g. piping, tanks, tunnels, vaults) in a nuclear power plant may be used in several applications governed by different requirements:

- Safety related:
 - Governed by codes such as ASME, RCC-M, etc.
- Non-safety-related:
 - Governed by nuclear regulators, when underground structures contain licensed material;
 - Governed by local, state or provincial regulations, when underground structures contain non-licensed material;
 - Some regulatory authorities require that certain non-SR systems (e.g. fire water, systems that might impact on an SR system, systems supporting station blackout) be included regardless of the contents of the system.

Given the age of some currently operating nuclear facilities, it is typically difficult to determine the material condition of these underground structures. Additionally, protective means for such structures (e.g. CP) may not have been maintained or ever installed in the first place. Potentially competing priorities for resources that focus on safety-critical systems, as opposed to those related to non-safety-related systems or those for which environmental impacts dominate, can hinder progress.

Noting, however, the potential impact of underground structure failure on public trust and on the environment, industry leaders and regulators have come together and agreed on the need for implementation of a programmatic approach across nuclear fleets. The ultimate goal is to proactively address the integrity of underground structures and where possible, prevent leakage prior to it happening by utilizing NDE technologies and processes.

5.2. REGULATORY AND CODE REQUIREMENTS

AMPs need to understand and document specific requirements as defined by national regulators. Although there are currently few specific prescriptive regulatory requirements for buried and underground piping and tank integrity management programmes, generic AMP requirements can be applied.

Industry leaders in some jurisdictions have issued proactive guidelines and recommendations, which are monitored by national regulators. Some of these guidelines set out strict milestones for the development and implementation of management programmes. Most common are those based on NEI 09-14 guidelines [45] and EPRI recommendations for an effective buried and underground piping and tanks programme [227].

The EPRI document identifies the data necessary for developing a safe and cost effective underground piping and tank integrity programme, in many cases in the form of checklists and tables, with applicable references for further details. It details programme requirements, risk ranking processes, fitness for service evaluations, repairs, prevention, mitigation and long term strategies. It is aligned with NEI 09-14 guidelines.

NEI guidelines are designed to provide reasonable assurance of structural and leakage integrity of in-scope underground piping and tanks, with special emphasis on piping and tanks that contain licensed materials. The initiative includes all buried and underground piping and tanks that are outside of a building and below grade (whether or not they are in direct contact with the soil) if they are safety related, contain licensed material or are known to be contaminated with licensed materials, or contain environmentally sensitive material.

The guidelines contain five steps for setting up and implementing a programme:

— Step 1: Procedures and oversight:

- Identify plant programmes or measures that manage the material condition of components within the initiative's scope;
- Establish necessary controls and processes to coordinate applicable programmes and measures and ensure they meet the intent of the initiative;
- Establish clear roles and responsibilities, including senior level accountability for implementation of the initiative.
- Step 2: Prioritization: Prioritization of underground piping and tanks is done by a risk ranking analysis and shall consider the following attributes:
 - Age;
 - Function;
 - Locations and layout;
 - Materials and design;
 - Process fluid (including piping flow rate and contents);
 - Soil condition and chemistry;
 - Plant operating history;
 - Leakage history;
 - Internal corrosion consideration (such as FAC for piping only and MIC);
 - Coating and lining;
 - Wet or alternately dry;
 - Health of CP systems, if applicable;
 - Based on the above data and other information, determine:
 - The likelihood of failure of each component;
 - The consequences of failure of each component.
 - A means to update the prioritization scheme as necessary;
 - Process(es) to allow retrieval of key programme data;
 - Relevant industry OPEX.
- Step 3: Condition assessment plan(s): Taking into account the results of prioritization along with plant and industry experience, plant licensing commitments and trending of past inspection data to define inspection locations, inspection methods and inspection schedules that will provide reasonable assurance of integrity of components. These plans shall include the following attributes:
 - Identification of underground piping and tanks to be assessed;
 - Potential assessment techniques;
 - Assessment schedules that take into account the relative priority of components. This schedule should be coordinated to ensure that the components with the highest overall priority are addressed first;
 - Assessment of CP, if applicable.
- Step 4: Plan implementation: implementation of the condition assessment plan for underground piping and tanks:
 - After prioritization is performed, an inspection process should address all piping and tanks within the programme's scope to ensure the relative importance of components is recognized and more important components are inspected first, when possible.
- Step 5: Asset management plan:
 - Inspection results shall be used as input to the development of asset management plans.

Table 21 contains a list of major regulatory requirements and guidelines for ageing, buried and underground pipe and tank management and CP obtained from a variety of jurisdictions. Appendix III contains additional standards related to pipe and tank design, fabrication, coatings and related subjects.

Text cont. on p. 154.

TABLE 21. SAMPLE TANKS BY COUNTR'	CODES, STANDARDS, REGULATIONS AND GUIDES APPLICAH Y OF ORIGIN	LE TO BURIED AND UNDERGROUND PIPING AND
Country	Document	Commentary relative to ageing management and equipment considerations
Australia	AS 2832.1: Cathodic Protection of Metals — Part 1: Pipes and Cables, Standards Australia [228]	Specifies requirements for CP of buried or submerged metallic pipes and cables
	AS 2832.2: Cathodic Protection of Metals — Part 2: Compact Buried Structures, Standards Australia [229]	Provides guidelines for CP of external surfaces of compact buried structures, including tank farms, service station tanks, tower footings, steel pilings (in soil), short well casings, compressor and pump stations and associated pipework
	AS 2832.3-2005: Cathodic Protection of Metals — Part 3: Fixed Immersed Structures [230]	Specifies requirements for the CP of external surfaces of fixed immersed structures, including offshore platforms, wharves, jetties, pontoons, sewage treatment plants, water treatment plants, lock gates, pump station piles in rivers, weirs, mooring buoys, piling, foundations and water inlet/outlet structures
	AS 2832.4-2006: Cathodic Protection of Metals — Part 4: Internal Surfaces [231]	Specifies requirements for CP internal surfaces of pipes and structures, including heat exchangers, hot water systems, clarifiers, ballast and water storage tanks, cooling conduits and processing plants. Surfaces may contain water, sea water, drinking water, brackish water, sewage or brines.
Canada	CNSC REGDOC-2.6.3: Fitness for Service — Aging Management [232]	Sets regulatory requirements for managing ageing of SSCs of a nuclear power plant. Replaces RD-334 [233]. Requires a documented overall integrated AMP framework and SSC-specific AMPs. Condition assessments shall be completed as part of the review of ageing for long term operation.
	RD/GD-369: Licence Application Guide: Licence to Construct a Nuclear Power Plant [234]. Section 4.2 on site reference data and section 13.6/7 on environmental monitoring and management.	Licence applicant to provide information on geotechnical data and construction of buried structures. Applicant to provide information on environmental monitoring and management programmes.
	CAN/ULC S603.1: External Corrosion Protection Systems for Steel Underground Tanks for Flammable and Combustible Liquids [235]	Covers external corrosion protection systems on steel non-pressure tanks that are used for underground storage of flammable liquids and combustible liquids. Includes cathodically protected tanks, composite tanks, jacketed tanks and coated tanks.

TABLE 21. SAMPLE TANKS BY COUNTRY	CODES, STANDARDS, REGULATIONS AND GUIDES APPLICA OF ORIGIN (cont.)	BLE TO BURIED AND UNDERGROUND PIPING AND
Country	Document	Commentary relative to ageing management and equipment considerations
	CANDU Owners Group: Buried piping guideline [236]	Provides an interpretation of a programme based approach using recommendations developed by EPRI to aid in implementing a buried piping programme at CANDU stations
	CSA N285.7: Periodic Inspection of CANDU Nuclear Power Plant Balance of Plant Systems and Components [237]	New (2015) standard on inspection of secondary side systems important to safety (including systems containing buried piping)
European Union	Pressure Equipment Directive 97/23/EC [47]	Concerns items such as vessels, pressurized storage containers, heat exchangers, steam generators, boilers, industrial piping, safety devices and pressure accessories. Provides guidelines for evaluation, design, manufacturing and materials for pressure retaining equipment. Requires that materials for pressurized parts must "not be significantly affected by ageing". Requires recording of position and route of underground piping in technical documentation to facilitate safe maintenance, inspection or repair.
	EN 12068: Cathodic Protection. External Organic Coatings for the Corrosion Protection of Buried or Immersed Steel Pipelines Used in Conjunction with Cathodic Protection. Tapes and Shrinkable Materials [238]	Specifies functional requirements and test methods for external organic coatings based on tapes or shrinkable materials to be used for corrosion protection of buried and immersed steel pipelines in conjunction with CP
	EN 12473: General Principles of Cathodic Protection in Sea Water [239]	Covers general principles of CP, including criteria for protection, environmental and design considerations, secondary effects of CP and an introduction to other standards in the series
	EN 12474: Cathodic Protection for Submarine Pipelines [240]	Establishes general criteria and recommendations for design, installation, monitoring and commissioning of CP systems for submarine pipelines
	EN 12499: Internal Cathodic Protection of Metallic Structures [241]	Specifies structures, electrolytes, metals and surfaces that can be protected against corrosion by internal CP; specifies conditions for application of internal CP; provides guidelines on realization and operation of efficient CP systems for specific structures (domestic water heaters, appliances for heating and storage, variable level feed tanks, filtering tanks, internal well casing surfaces, internal pipe surfaces, tubular heat exchangers)

IANKS BY CUC	NIKY UF UKIGIN (cont.)	
Country	Document	Commentary relative to ageing management and equipment considerations
	EN 12501-1: Protection of Metallic Materials against Corrosion. Corrosion Likelihood in Soil, Part 1. General [242]	Provides a basis for assessing corrosion likelihood in soil of buried metallic structures (e.g. pipelines, metal sheathed cables, storage tanks, sheet pilings, tower support anchors, culverts and earth reinforcement). Metallic materials covered are steel, cast iron, stainless steel, copper, lead, aluminium, zinc and their alloys. These metallic materials may be uncoated or coated with other metallic materials.
	EN 12501-2: Protection of Metallic Materials against Corrosion. Corrosion Likelihood in Soil, Part 2. Low Alloyed and Non Alloyed Ferrous Materials [243]	Deals with assessment of corrosion load in soil for low alloyed and non-alloyed ferrous materials in direct contact with soil
	EN ISO 12696: Cathodic Protection of Steel in Concrete [259]	See ISO
	EN 12954: Cathodic Protection of Buried or Immersed Metallic Structures — General Principles and Application for Pipelines [44]	Standard applicable to protection of all types of buried or immersed metallic structures, especially pipelines. Covers CP principles, prerequisites for application, design, installation, commissioning, inspection and maintenance of CP systems.
	EN 13480-6: Metallic Industrial Piping — Part 6: Additional Requirements for Buried Piping [244]	EN 13480 covers metallic industrial piping; Part 6 provides additional requirements for BP. While not specifically mentioning ageing, it provides standards for material selection, design calculations, installation, sleeving, corrosion protection, examination and testing.
	EN 13508-2: Conditions of Drain and Sewer Systems Outside Buildings. Visual Inspection Coding System [245]	Provides methodology for classifying sewer system degradation based on visual inspections
	EN 13509: Cathodic Protection Measurement Techniques [246]	Details measuring methods to be used for assessing effectiveness of CP as well as measurements and measures taken to monitor CP during operation
	EN 13636: Cathodic Protection of Buried Metallic Tanks and Related Piping [247]	Specifies principles for implementation of a system of CP against corrosive attacks on buried metal tanks and associated piping
	EN 14505: Cathodic Protection of Complex Structures [248]	Applicable to structures which are to be cathodically protected but cannot be electrically isolated, whether for technical or safety reasons, from foreign metallic structures situated in the same electrolyte as structure to be protected

TABLE 21. SAMFLE O TANKS BY COUNTRY	ODES, SIANDAKDS, KEGULAHONS AND GUIDES AFFLICA OF ORIGIN (cont.)	SLE IU BUKIED AND UNDEKGKUUND FIFING AND
Country	Document	Commentary relative to ageing management and equipment considerations
	EN 15280: Evaluation of a.c. Corrosion Likelihood of Buried Pipelines Applicable to Cathodically Protected Pipelines [249]	Applicable to buried CP metallic structures influenced by AC traction systems and/or power lines. Provides limits, measurement procedures, mitigation measures and information to deal with AC interference and evaluation of corrosion likelihood.
	EN 50162: Protection against Corrosion by Stray Current from Direct Current Systems [250]	Establishes general principles to be adopted to minimize effects of stray current corrosion caused by DC on buried or immersed metal structures
Finland	STUK Guide YVL A.8: Ageing Management of a Nuclear Facility [251]	Licensee shall specify AMP, including functions, duties and responsibilities to ensure conformity over its life cycle. Component operating conditions to be monitored.
France	RCC-M: Design and Construction Rules for Mechanical Components of PWR Nuclear Islands [252]	Provides design and construction rules for mechanical components of PWR nuclear islands. Rules are applicable to design and manufacture of pressure boundaries of mechanical equipment, including reactor fluid systems and other components which are not subject to pressure: vessel internals, supports for pressure components subject to the RCC-M, nuclear island storage tanks. Requires designer to incorporate additional thickness into components/tanks if subject to in-service corrosion.
	ETC-C: EPR Technical Code for Civil Works [253]	Contains rules for design, construction and testing of civil engineering structures. Describes principles and requirements for safety, serviceability and durability conditions for concrete and steelworks structures based on Eurocode design principles. There is a dedicated section for RCCP pipe in the document.
Germany	RSK Recommendation 22.07.2004: Management of Ageing Processes at Nuclear Power Plants [254]	Recommends an annual report on ageing management be submitted to competent supervisory authority
	KTA 1403: Ageing Management in Nuclear Power Plants [255]	Requires annual review of plant ageing status for system, structures and components

TABLE 21. SAMPLI TANKS BY COUNTR	E CODES, STANDARDS, REGULATIONS AND GUIDES APPLICAE &Y OF ORIGIN (cont.)	LE TO BURIED AND UNDERGROUND PIPING AND
Country	Document	Commentary relative to ageing management and equipment considerations
Hungary	N.B.SZ Guideline 1.26: Surveillance of Ageing Management [256]	Describes nuclear authority needs connected to the ageing management documents and describes the activity of the authority. Describes required content of AMPs.
	NP-017: Basic Requirements for Power Unit Lifetime Extension of Nuclear Power Plant [257]	Establishes general criteria and requirements for evaluation of possibility of nuclear power plant power unit service life extension and for actions to assure safety during the prolonged life period
	Government Decree No. 118/2011 (VII. 11.) on Nuclear Safety Requirements of Nuclear Facilities and Related Regulatory Activities. Vol. 1: Nuclear Safety Authority Procedures of Nuclear Facilities [258]	Requires comprehensive review of ageing management of passive and long-life system components in licence request; inspector to review ageing management activities; include ageing in periodic safety assessments
International (ISO)	ISO 12696: Cathodic Protection of Steel in Concrete [259]	Not ageing specific, but covers performance requirements for CP of steel in concrete, in both new and existing structures (buildings and civil engineering structures, including normal reinforcement and prestressed embedded reinforcement)
	ISO 15589-1: Petroleum, Petrochemical and Natural Gas Industries — Cathodic Protection of Pipeline Transportation Systems — Part 1: On-Land Pipelines [131]	Ageing not directly addressed. Provides design requirements, criteria for CP, information re ICCP and SACP systems, monitoring facilities, commissioning and recommendations for frequencies of inspections.
Russian Federation	STO 1.1.1.01.006.0327-2008: NPP Service Life Extension [260]	Determines procedure, sequence and performance time of life extension work Determines non-recoverable and irreplaceable power unit elements, which need lifetime extension
	STO 1.1.1.01.007.0281-2010: Lifetime Management of Elements of NPP Power Units [261]	Establishes procedure of lifetime management of elements of nuclear power plant power units
	PNAE G-7-008-89: Rules for Arrangement and Safe Operation of Equipment and Piping of Nuclear Power Installations [262]	Defines requirements for design and operation of equipment and pipelines of plants that ensure reliability and safety. Buried piping not specifically mentioned.
	GOST 51164: Steel Main Pipelines. General Requirements for Protection Against Corrosion [263]	Ageing not directly addressed. Provides requirements for protective coatings, CP and safety. Includes various coating test methods.

		Commentary relative to ageing management and equipment
Country	Document	considerations
	GOST 9.602: Unified System of Corrosion and Ageing Protection. Underground Constructions. General Requirements for Corrosion Protection [264]	Requirements for corrosion protection of external surfaces of underground low-carbon steel structures such as pipelines and tanks, power cables up to 10 kV, communication cables with steel jackets, steel structures of unmanned signalling posts, as well as facilities generating sneak currents, including electrified rail transport, direct current communication lines and industrial facilities consuming electric power for process
	RD 153-39.4-091-01: Instructions for Protection of Urban Underground Pipelines from Corrosion [265]	Guidance Document (RD) applies to protection against corrosion in design, construction, reconstruction, maintenance and repair of steel pipes (excluding gas with a gas pressure of 1.2 MPa and heat pipelines), to lay within cities and towns, industrial enterprises and intersettlement gas pipelines. Establishes standards for design, application, order and organization of anticorrosion measures relating to protective insulating coating on underground pipelines and tanks and their electrochemical protection.
United States of America	US Code of Federal Regulations. Title 10. Energy, Part 50 — Domest	c Licensing of Production and Utilization Facilities [266]
	Part 50.65: Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants [267]	Intended to provide basis that an effective programme to manage and to mitigate the effects of ageing is being implemented
	Appendix A: General Design Criteria for Nuclear Power Plants [268]	Ageing not addressed directly
	Part 54: Requirements for Renewal of Operating Licenses for Nuclear Power Plants [269]	Provides methodology for determination of need for an ageing management review of long lived structures
	US Code of Federal Regulations. Title 40. Protection of Environ	tent, parts 280 [270], 281[271] and 282 [272] re USTs
	Parts 280.20 & 21: Performance standards for new UST systems (underground storage tank systems containing petroleum or hazardous substances)/Upgrading of Existing UST Systems [273, 274]	Defines standards related to new or upgraded UST systems containing regulated substances
	Part 281: Underground Storage Tanks: State Program Approval [271]	Defines regulations for approval of states to run underground storage tank programmes in lieu of the federal programme

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NUREG/CR-6876: Risk-Informed Assessment of Degraded Buried Pping Describes research performed to assess effects of age points degradation over plans, focusing spreach to evaluate most commarking effects in (general wall thiming ad lecalificad loss of material) Systems in Nuclear Power Plans [275] Describes research and thiming ad lecalificad loss of material to the methodol in the methodol buried piping degradation over time were included in the methodol buried piping to evaluate most commarking. NUREG-1800: Standard Review Plans [276] Provides prime to USNRC staff reviews to assumate performing static previews of applications for Nuclear Power Plans [276] NUREG-1800: NuM41: Buried and Underground Piping and Tanks, within Generic Aging Lessons Learned (GALL) Report [186] Provides prime to USNRC staff reviews to assumate Generic Aging Lessons Learned (GALL) Report [186] NUREG-1800: Standard Review Plans [276] NUREG-1801 VLM41: Buried and Underground Piping and Tanks, within Generic Aging Lessons Learned (GALL) Report [186] NUREG-1801: VI.M41: Buried and Underground Piping and Tayauris are actions, continuation Proverses, administration advartable and underground Piping and travelating periods of operatins. AUX NUREG-1801: VI.M41: Buried and Underground Piping and travelating reviews of the reviews of the review of the review of the review of the review of the reviews of the reviews of the reviews of the reviews of the review of the reviews of		USNRC kegulatory Guides, NUREG Reports, Inspection Manual Chapters (IMC	s), Information Notices (INs) and Inspection Procedures (IPs)
NUREG-1800: Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants [276] Provides guidance to USNRC staff reviews of applicatio power plant operating licences in accordance with 10 Power plant power plant licence according prediction and w augmented for extended periods of operation. AMP Programmes are adequate without modification and w augmented for extended periods of operation. AMP Provider and underground piping and tanks and describ programmes are adequate without modification and w augmented for extended periods of operation. AMP Provider and underground piping and tanks and describ programmes are adequate without modification and w augmented for extended periods of operation. AMP Provides guidelines to USNRC staff operator, inclus periods of aperation of light water reactors, inclus site inspections associated with licence reaveal	NUREC Systems	i/CR-6876: Risk-Informed Assessment of Degraded Buried Piping s in Nuclear Power Plants [275]	Describes research performed to assess effects of age-related buried piping degradation at nuclear power plants, focusing on a risk-informed approach to evaluate most common ageing effects in buried piping (general wall thinning and localized loss of material pitting). Effects of degradation over time were included in the methodology for assessing buried piping.
NUREG-1801 XI.M41: Buried and Underground Piping and Tanks, within NUREG-1801 contains USNRC staff generic evaluat Generic Aging Lessons Learned (GALL) Report [186] AMPs and documents the technical basis for determine programmes are adequate without modification and wagemented for extended periods of operation. AMP X buried and underground piping and tanks and describ programmes are adequate without modification and wagemented for extended periods of operation. AMP X buried and underground piping and trending requirements, accept corrective actions, programmes are adequate without modification and wagement for programmes are adequate without modification and wagement programmes are adequate without modification and wagement for any argumentation processes, administre corrective actions, proving its score, proventive actions, proving and trending requirements, accept corrective actions, proving and tanks within the score of the Revision 2 Aging Management Program AMP XI.M41, 'Buried and Underground Piping and tanks within the score of the Revision 2 Aging Management Program AMP XI.M41, 'Buried and Underground Piping and tanks within the score of the Revision 2 Aging Management Program AMP XI.M41, 'Buried and Underground Piping and tanks within the score of the Revision 2 Aging Management Program AMP XI.M41, 'Buried and Underground Piping and tanks within the score of the Revision 2 Aging Management Program AMP XI.M41, 'Buried and Underground Piping and tanks within the score of the Revision 2 Aging Management Program AMP XI.M41, 'Buried and Underground Piping and tanks wither reactor piping and tanks (10 CFR Part 7	NUREC Applica	3-1800: Standard Review Plan for the Review of License Renewal tions for Nuclear Power Plants [276]	Provides guidance to USNRC staff reviewers to assure quality and uniformity in performing safety reviews of applications to renew nuclear power plant operating licences in accordance with 10 CFR Part 54 [269]
LR-JSG-2011-03: Changes to the Generic Aging Lessons Learned Report Revision 2 Aging Management Program AMP XI.M41, 'Buried and Underground Piping and Tanks' [198] Amends GALL Report AMP XI.M41 [186] documen acceptable approach to managing the effects of ageing underground piping and tanks within the scope of the Rule (10 CFR Part 54 [269]) IMC 2515: Light-Water Reactor Inspection Program — Operation Phase [277] Provides guidelines to USNRC staff on review and in to ensure safe operation of light water reactors, incluc site inspections associated with licence renewal	NUREC Generic	3-1801 XI.M41: Buried and Underground Piping and Tanks, within Aging Lessons Learned (GALL) Report [186]	NUREG-1801 contains USNRC staff generic evaluation of existing AMPs and documents the technical basis for determining where existing programmes are adequate without modification and where they should be augmented for extended periods of operation. AMP XI.M41 is specific to buried and underground piping and tanks and describes an acceptable programme, including its scope, preventive actions, parameters monitored/inspected, methods and frequencies for detecting ageing effects, monitoring and trending requirements, acceptance criteria, corrective actions, confirmation processes, administrative controls and OPEX.
IMC 2515: Light-Water Reactor Inspection Program — Operation Phase [277] Provides guidelines to USNRC staff on review and in to ensure safe operation of light water reactors, incluc site inspections associated with licence renewal	LR-ISG Revisio Piping 6	-2011-03: Changes to the Generic Aging Lessons Learned Report n 2 Aging Management Program AMP XI.M41, 'Buried and Underground und Tanks' [198]	Amends GALL Report AMP XI.M41 [186] documentation for an acceptable approach to managing the effects of ageing of buried and underground piping and tanks within the scope of the License Renewal Rule (10 CFR Part 54 [269])
	IMC 25	15: Light-Water Reactor Inspection Program — Operation Phase [277]	Provides guidelines to USNRC staff on review and inspection activities to ensure safe operation of light water reactors, including post-approval site inspections associated with licence renewal

TANKS BY COUNTRY	OF ORIGIN (cont.)	
Country	Document	Commentary relative to ageing management and equipment considerations
	IMC 2516: Policy and Guidance for License Renewal Inspection Programs [278]	Provides guidelines to USNRC staff on review and inspection activities associated with licence renewal
	IP-71002: License Renewal Inspections [279]	Provides procedures for inspecting and verifying documentation, implementation and effectiveness of programmes and activities associated with an applicant's licence renewal programme. Inspection assesses adequate implementation of AMPs resulting from an applicant's licence renewal programme and may be performed in conjunction with a scoping and screening inspection.
	IP-71003: Post-Approval Site Inspection for License Renewal [280]	Provides procedures for inspecting and verifying completion of licence renewal commitments and licence conditions added as part of a renewed licence and ensuring that selected AMPs are implemented in accordance with licence renewal regulations
	NRC Inspection Manual Temporary Instruction 2515/182: Review of the Implementation of the Industry Initiative to Control Degradation of Underground Piping and Tanks (ADAMS ML11119A167) [281]	Instruction to USNRC inspectors to determine whether licensees are implementing industry initiatives on underground piping and tank integrity and to gather information to enable the staff to assess whether the initiative provides reasonable assurance of structural and leakage integrity of buried piping and underground piping and tanks
	Regulatory Guide 1.137: Fuel-Oil Systems for Emergency Power Supplies [282]	Recommends ANSI/ANS-59.51-1997 (R2015: Fuel Oil Systems for Safety-Related Emergency Diesel Generators, American Nuclear Society, La Grange Park, IL (2015)) be followed, which requires that protection against external and internal corrosion be provided for the fuel oil system. Acceptable standards related to internal and external coatings and CP systems are defined.
	American Petroleum Ir	nstitute (API)
	API Standard RP 579-1/ASME FFS-1: Fitness-For-Service [283]	Describes standardized fitness for service assessment techniques for pressurized equipment used in the petrochemical industry

TABLE 21. SAMPLE C TANKS BY COUNTRY (ODES, STANDARDS, REGULATIONS AND GUIDES APPLICAI JF ORIGIN (cont.)	BLE TO BURIED AND UNDERGROUND PIPING AND
Country	Document	Commentary relative to ageing management and equipment considerations
	API Standard 650: Welded Steel Tanks for Fuel Storage [284]	Establishes minimum requirements for material, design, fabrication, erection and testing for vertical, cylindrical, above ground, closed- and open-top wielded carbon or stainless steel storage tanks in various sizes and capacities
	API Standard 653: Tank Inspection, Repair, Alteration and Reconstruction [285]	Covers inspection, repair, alteration and reconstruction of steel above ground storage tanks used in the petroleum and chemical industries
	API Standard 1104: Welding of Pipelines and Related Facilities [87]	Covers gas and arc welding of butt, fillet and socket welds in carbon and low alloy steel piping used in compression, pumping and transmission of crude petroleum, petroleum products, fuel gases, carbon dioxide and nitrogen, and where applicable, it covers welding on distribution systems
	API Standard 1163: In-Line Inspection Systems Qualification [286]	Covers the use of in-line inspection systems for onshore and offshore gas and hazardous liquid pipelines
	API RP 651: Cathodic Protection of Aboveground Petroleum Storage Tanks [287]	Presents procedures and practices for achieving effective corrosion control on above ground steel storage tank bottoms through use of CP
	API RP 1102: Recommended Practice Steel Pipelines Crossing Railroads and Highways [288]	Covers design, installation, inspection and testing required to ensure safe crossings of steel pipelines under railroads and highways
	API RP 1110: Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide [289]	Recommended practice for pressure testing of steel pipelines and pipeline facilities
	API RP 1631: Interior Lining and Periodic Inspection of Underground Storage Tanks [290]	Provides minimum recommendations for the interior lining of existing steel and fibreglass reinforced plastic underground tanks used to store petroleum based motor fuels and middle distillates
	API RP 1632: Cathodic Protection of Underground Petroleum Storage Tanks and Piping Systems [207]	Withdrawn in 2013. Document was conveyed to NACE. API will no longer revise.

Country	Document	Commentary relative to ageing management and equipment
	ASCE/American Life	ines Alliance
	Guidelines for the Design of Buried Steel Pipe [221]	Provides design provisions to evaluate buried pipe integrity for a variety of applied loads. Applicable to new carbon or alloy steel pipe, welded pipe and its interfaces with buildings and equipment. Addresses internal pressure, earth loads, surface live and impact loads, buoyancy, thermal expansion, displacement, subsidence, earthquake, blasting, fluid transients and in-service relocation.
	Buried Flexible Steel Pipe: Design and Structural Analysis, ASCE Manuals and Reports on Engineering Preactice No.119 [291]	Provides appropriate analytical concepts to address principles of buried steel pipe design for water and wastewater
	Seismic Analysis of Safety-Related Nuclear Structures and Commentary (ASCE 4-98) [292]	Section 3.5.2 addresses seismic design of buried piping
	American Society for Testing	of Materials (ASTM)
	ASTM G158-98(2010) Standard Guide for Three Methods of Assessing Buried Steel Tanks [214]	Defines acceptable standards for assessing buried steel tanks
	ASTM E1990-14 Standard Guide for Performing Evaluations of Underground Storage Tank Systems for Operational Conformance with 40 CFR, Part 280 Regulations [293]	Defines acceptable standards for assessing buried steel tanks

ASNE Internation ASNE Internation ASNE Internation Section XI — Rules for Inservice Inspection of Nuclear Power Plant Provides rules for examination, in-service and liquid mest cooled moder power plant Components [25] Section XI — Rules for Inservice Inspection of Nuclear Power Plant Provides rule for examination, in-service and liquid mest cooled moder power plant Section XI — Rules for Inservice Inspection of Nuclear Power Plant Provides Induct Nuclear adequire adequire adeal Inservice and Inservice of stable adeal Inservice Inspections to evolute a trademost state advince formation and input while in operation and found mest concervice present in the section of the Inservice Inservice Inservice Inserved and Inservice	Commentary relative to ageing management and equipment considerations
Section XI — Rults for Inservice Inspection of Nuelear Power Plant Components [25] To components [25] Components [25] Components [25] President and replace molecular power plant and liquid metal cooled modern power aftery is president and programme of shade MFI- sections to evidence adquare statey. Apped inspections to evidence adquare state. Apped inspections to evidence adquare mechanical programme, and non-keen fully accepted by the U inspections (evidence). Advant ASME XI Code Case N-806. Eviduation of Metal Loss in Class 2 and 3 Metallic Pipung Burred in a Back-Filled Trench [294] Provides formulas to evaluate mechanical provides for advare and and beased provides formulas to evaluate mechanical provides formulas to evaluate mechanical provides formulas to evaluate mechanical provides formulas to evaluate mechanical provides formulas for flass of fradication for provides formulas for the evaluate mechanical provides formulas for the evaluate mechanical provides formulas for the evaluate mechanical provides formulas for the evaluate for the evaluate mechanical provides formulas for the evaluate mechanical provides formulas for the evaluate mechanical provides f	AE International
ASME XI Code Case N-806: Evaluation of Metal Loss in Class 2 and 3 Metallic Provides formulas to evaluate mechanical Piping Buried in a Back-Filled Trench [294] Duried piping corroded by wall thinning. Case had not been fully accepted by the Uuse on a case by case basis. Duried piping corroded by the Uuse on a case by case basis. AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Prestressed-Concrete Pressure Pipe, Steel-Cylinder Type Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Design of Ageing not addressed Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Unstructed Pressure Pipe, Steel-Cylinder Type Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Unstructed Pressure Pipe, Steel-Cylinder Type Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Unstructed Type Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Unstructed Type Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Unstructed Type Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing to Unstructed Type Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing to Unstructed Type Ageing not addressed ANN Nuclear Liability Insurance Guideline 07-01: Potentia	Provides rules for examination, in-service testing and inspection and repair and replacement of components and systems in light water coc and liquid metal cooled nuclear power plants. Details requirements to maintain the plant while in operation and to return the plant to servic following plant outages and repair or replacement activities. These ru require a mandatory programme of scheduled examinations, testing a inspections to evidence adequate safety. Methods of non-destructive examination to be used and flaw size characterization are also descril Specific clauses on ageing include IWE-1241 (areas subject to accelerated ageing require augmented examination), IWL-2512 (inaccessible areas such as buried concrete should have technical evaluation at maximum ten-year intervals and a condition monitoring programme), and non-mandatory Appendix R on risk-informed inspections (expert panels to consider ageing effects in evaluating pil safety significance).
AWWA AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Prestressed-Concrete Pressure Pipe, Steel-Cylinder Type Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Prestressed-Concrete Pressure Pipe, Steel-Cylinder Type Ageing not addressed AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Prestressed-Concrete Pressure Pipe, Steel-Cylinder Type Ageing not addressed ANI Nuclear Liability Insurance Guideline 07-01: Potential for Unmonitored and Unplanned Off-Site Releases of Radioactive Material [295] Provides advice on designs and acceptable programmes for storage tanks, undergrou could impact on off-site releases of radio external inspections comprehensive inten- volumetric NDE) can be employed.	Metallic Provides formulas to evaluate mechanical integrity and remaining lif buried piping corroded by wall thinning. At the time of writing this C Case had not been fully accepted by the USNRC and is only approve use on a case by case basis.
AWWA C301 [35]/C304 [36]: Standards for Manufacturing and Design of Ageing not addressed Ageing not addressed Prestressed-Concrete Pressure Pipe, Steel-Cylinder Type American Nuclear Insurers (ANI) American Nuclear Insurers (ANI) American Nuclear Insurers (ANI) ANI Nuclear Liability Insurance Guideline 07-01: Potential for Unmonitored and Provides advice on designs and acceptabl Unplanned Off-Site Releases of Radioactive Material [295] Provides advice on designs and acceptabl Provides advice on designs and acceptabl Provides advice on designs and acceptabl Unplanned Off-Site Releases of Radioactive Material [295] ANI Nuclear Liability Insurance Guideline 07-01: Potential for Unmonitored and Provides advice on designs and acceptabl Programmes for storage tanks, undergrou could impact on off-site releases of radio	AWWA
American Nuclear Insurers (ANI) American Nuclear Issuers (ANI) ANI Nuclear Liability Insurance Guideline 07-01: Potential for Unmonitored and Provides advice on designs and acceptabl programmes for storage tanks, undergrou Unplanned Off-Site Releases of Radioactive Material [295] Provides advice on designs and acceptabl programmes for storage tanks, undergrou could impact on off-site releases of radio external inspections comprehensive interview interview of tanks	of Ageing not addressed
ANI Nuclear Liability Insurance Guideline 07-01: Potential for Unmonitored and Provides advice on designs and acceptabl Unplanned Off-Site Releases of Radioactive Material [295] programmes for storage tanks, undergrou could impact on off-site releases of radio external inspections comprehensive intervolution volumetric NDE) can be employed.	Nuclear Insurers (ANI)
	itored and Provides advice on designs and acceptable inspection and testing programmes for storage tanks, underground piping and other system could impact on off-site releases of radioactive material. In lieu of external inspections comprehensive internal inspections (visual and volumetric NDE) can be employed.

TABLE 21. SAN TANKS BY COU	1PLE CODES, STANDARDS, REGULATIONS AND GUIDES APPLICAE INTRY OF ORIGIN (cont.)	sle to buried and underground fifting and
Country	Document	Commentary relative to ageing management and equipment considerations
	EPRI Note: Many other EPRI reports are available and are	referenced in the text of this publication.
	EPRI Report 1021175: Recommendations for an Effective Program to Control the Degradation of Buried and Underground Piping and Tanks [227]	Recommendations to help plant engineers prevent and mitigate degradation and leaks in buried and underground piping and buried tanks. Referenced by NEI 09-014 [45].
	EPRI Report 3002000596: Cathodic Protection Application and Maintenance Guide. Vol. 1: Buried Piping [206]	Provides an application and maintenance guide that is specific to CP of buried piping at nuclear power plants. Both impressed current and galvanic anode systems are discussed.
	EPRI Report 3002000682: Balance of Plant Corrosion — The Underground Piping and Tank Reference Guide [296]	Provides reference information on many of the tasks and technologies that plant owners may find useful in implementing the Underground Piping and Tanks Integrity Initiative and programmatic tasks defined in EPRI Report 1021175 [227]
	EPRI Report 3002003071: Guidelines for Tank Inspections [297]	Provides guidelines for developing tank inspection plans
	EPRI Report 3002004395: Non-destructive Evaluation: Buried Pipe NDE Reference Guide [298]	Provide an overview of commercially available NDE technology that can be used to examine buried and underground pipe
	NACE	
	10A392: Effectiveness of Cathodic Protection [299]	Guide for external corrosion control of thermally insulated underground metallic surfaces and considerations of CP effectiveness
	SP0100 (formerly RP0100): Cathodic Protection to Control External Corrosion of Concrete Pressure Pipelines and Mortar-Coated Steel Pipelines for Waste or Waste Water Service [300]	Guidelines for corrosion control of PCCP through application of CP
	SP0104-2014 (formerly RP0104): The Use of Coupons for Cathodic Protection Monitoring Applications [301]	Addresses applications for CP coupons attached to buried pipelines to determine levels of corrosion protection. Appendices cover coupons attached to other structures such as USTs, on-grade storage tank bottoms and steel in reinforced concrete structures.

TANKS BY COUNTRY	ODES, STANDARDS, REGULATIONS AND GUIDES AFFLICA OF ORIGIN (cont.)	BLE IO BURIED AND UNDERGROUND FIFING AND
Country	Document	Commentary relative to ageing management and equipment considerations
	SP0169 (formerly RP0169): Control of External Corrosion on Underground or Submerged Metallic Piping Systems [208]	Includes information on determining need for corrosion control, piping system design, coatings, CP criteria and design, installation of CP systems, and control of interference currents
	SP0200: Steel-Cased Pipeline Practices [129]	Details acceptable practices for the design, fabrication, installation and maintenance of steel-cased metallic pipelines
	SP0207: Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines [302]	Presents procedures for performing a close interval potential survey (CIPS) and direct current voltage gradient (DCVG) on buried or submerged metallic pipelines
	SP0285 (formerly RP0285): Corrosion Control of Underground Storage Tank Systems by Cathodic Protection [209]	Provides recommendations for controlling external corrosion on UST systems by CP. Specifically addressed are existing bare and coated mild steel tanks; new coated mild steel tanks; metallic piping and flexible connectors; and other metallic components.
	SP0286 (formerly RP0286): Electrical Isolation of Cathodically Protected Pipelines [205]	Details requirements necessary to ensure adequate isolation of CP'd pipelines, especially those with high-quality dielectric coatings
	SP0288-2011: Inspection of Lining Application in Steel and Concrete Equipment [303]	Provides appropriate inspection requirements to verify compliance to a specification
	SP0502 (formerly RP0503): Pipeline External Corrosion Direct Assessment Methodology [8]	Describes external corrosion direct assessment process for assessing and reducing impacts of external corrosion on pipeline integrity. ECDA locates areas where defects can form in the future, not just areas where defects have already formed.
	SP0572: Design, Installation, Operation and Maintenance of Impressed Current Deep Anode Beds [202]	Presents guidelines for the design, installation, operation and maintenance of deep groundbeds used to control external corrosion of underground or submerged metallic structures by ICCP
	TM0106: Detection, Testing and Evaluation of Microbiologically Influenced Corrosion (MIC) on External Surfaces of Buried Pipelines [104]	Describes mechanisms by which MIC occurs in ferrous based metal pipes, types of microorganisms, methods of testing for bacteria, research results and test interpretation

TABLE 21. SAMPLE (TANKS BY COUNTRY	CODES, STANDARDS, REGULATIONS AND GUIDES APPLICAI OF ORIGIN (cont.)	3LE TO BURIED AND UNDERGROUND PIPING AND
Country	Document	Commentary relative to ageing management and equipment considerations
	TM0109: Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition [304]	Presents techniques for above ground evaluation of coating condition of underground metallic pipelines, including the AC attenuation survey, DCVG survey, (alternating current voltage gradient (ACVG) survey and Pearson survey
	TM0211: Durability Test for Copper/Copper Sulfate Permanent Reference Electrodes for Direct Burial Applications [203]	Documents test method to measure physical properties and relative stability of Cu/CuSO ₄ permanent reference electrodes when they are subjected to environmental stresses
	TM0497: Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems [305]	Provides test procedures to comply with CP requirements for buried or submerged steel, cast iron, copper or aluminium pipe
	National Fire Protection As	sociation (NFPA)
	Standard 25: Standard for the Inspection, Testing and Maintenance of Water- Based Fire Protection Systems [306]	Covers inspection, testing and maintenance of water based fire protection systems. Includes methods of investigating internal piping condition and obstructions.
	NEI	
	NEI 95-10: Industry Guideline for Implementing the Requirements of 10 CFR Part 54 — The License Renewal Rule [307]	Provides guidance in evaluating UST systems in order to meet US federal regulations related to environmental protection
	NEI 09-14: Guideline for the Management of Underground Piping and Tank Integrity [45]	Provides guidance in evaluating UST systems in order to meet US federal regulations related to environmental protection
	Petroleum Equipment I	astitute (PEI)
	RP900: UST Inspection and Maintenance [308]	Consolidates published and unpublished information from equipment manufacturers, service and installation contractors, petroleum marketers, as well as regulatory agencies concerning the proper inspection and maintenance of UST systems intended to store and dispense gasoline, diesel and related petroleum products at vehicle fuelling facilities
	RP1200: Testing and Verification of Spill, Overfill, Leak Detection and Secondary Containment Equipment at UST Facilities [309]	Provides guidelines for inspection and testing of leak detection, release prevention and overfill prevention equipment at UST facilities

TABLE 21. SAMPLE (TANKS BY COUNTRY	CODES, STANDARDS, REGULATIONS AND GUIDES APPLICA OF ORIGIN (cont.)	BLE TO BURIED AND UNDERGROUND PIPING AND
Country	Document	Commentary relative to ageing management and equipment considerations
	RP1400: Recommended Practices for the Design and Installation of Fueling Systems for Emergency Generators, Stationary Diesel Engines and Oil Burner Systems [310]	Provides recommended practices for design and installation of tanks, piping and auxiliary equipment for oil burners and stationary permanent systems that fuel diesel powered engines for pumps and generators
	Steel Tank Institu	te (STI)
	Cathodic Protection Testing Procedures for Sti-P3 USTs (R051) [211]	Describes equipment and procedures used to test the CP system of sti-P3 technology
	Recommended Practice for Corrosion Protection of Underground Piping Networks Associated with Liquid Storage and Dispensing Systems (R892) [210]	Assists owners and installers of underground and above ground tanks in the design, installation and monitoring of corrosion control systems for underground metallic piping
	Recommended Practice for the Addition of Supplemental Anodes to Sti-P3 USTs (R972) [212]	On occasion, tank owners of sti-P3 tanks find that the CP readings are more positive than the NACE recommended –850 mV criteria. In that case, the RP identifies ways to supplement the CP system so that the tank continues to be protected from corrosion.
	SP001 Standard for the Inspection of Aboveground Storage Tanks [311]	Provides inspection and evaluation criteria required to determine the suitability for continued service of above ground storage tanks until the next scheduled inspection
	SP131 Standard for Inspection & Repair Underground Steel Tanks [312]	Covers inspection, repair and modification of an atmospheric-type, shop fabricated, carbon and/or stainless steel underground storage tank. It applies to tanks storing stable liquids at atmospheric pressure.
	Underwriters' Labora	atories (UL)
	UL 1756 Standard for External Corrosion Protection Systems for Steel Underground Storage Tanks [313]	Covers pre-engineered CP systems intended to be completely installed at the factory on CS USTs. Also covers composite, jacketed and coated tank construction and tests.

5.3. GATHER CURRENT PLANT ACTIVITIES AND DOCUMENTATION

Details of available underground structure specific design and construction data, soil properties (pH, chloride concentration, sulphate concentration and soil resistivity), environmental conditions, coating and CP data (including locations of overprotection), operational history, inspection and surveillance history and any regulatory commitments are required for effective development and implementation of an underground piping and tank AMP. They are required for effective comparison with external experience.

Typical sources of required data are:

- Station drawings;
- Design manuals;
- Design calculations;
- Bills of material;
- Technical standards;
- Specifications;
- Surveillance procedures;
- System engineer records;
- Quality control records;
- Field verifications;
- Plant OPEX;
- Maintenance procedures;
- Maintenance history;
- Root cause reports.

Ensuring that data are placed in a special file or database (i.e. making them readily accessible) will save considerable time when evaluating component condition. Piping is typically separated into discrete segments to allow for effective monitoring. Adopting a systematic and consistent approach allows easy comparison with similar plants and also assists in the identification of gaps in data. Practical guidelines on implementation of an effective system for data collection and record keeping for ageing management purposes were first provided in IAEA Safety Series No. 50-P-3 [314]⁶.

5.4. SCREENING PROCESS/RISK RANKING/PROGRAMME SCOPE

Risk ranking allows for reducing the active monitoring scope of the buried and underground pipe and tank programme. Systems and lines can be excluded from active monitoring scope if the consequences of failure are minimal. The process is analogous to the screening process shown in fig. 3 of Ref. [3].

Risk-informed in-service inspection (RI-ISI) approaches are typically used to identify and prioritize inspection locations for buried and underground structures (piping, tanks, etc.). RI-ISI is a methodology using consequences of failure (greatest risk to plant operation and nuclear or personnel safety), failure potential and risk ranking to select such locations. The most common method of risk ranking involves creating a series of matrices that correlate failure likelihood against failure consequences (Table 22). The general process is defined in more detail in IAEA Nuclear Energy Series No. NP-T-3.1 [315]. USNRC [275], EPRI [227], NEI [45] and CSA [237] documents discuss its application to buried piping. Other reports cover RI-ISI approaches in general but not in terms specific to underground structures (e.g. Refs [316, 317]).

Engineers responsible for underground piping and tanks should document inspection plans and techniques based on their risk ranking to establish a reasonable assurance of susceptible system/components within the programme scope. The likelihood and consequences of failure are combined to identify the highest risk piping, and plant and particular pipe sections are chosen that are representative of conditions over a wide area.

Risk ranking may also be performed using qualified software tools. Examples include EPRI's BPWORKS, Structural Integrity Associates Inc.'s MAPPro and AREVA's COMSY.

⁶ This publication is no longer considered an up to date IAEA Safety Standard.

TABLE 22. RISK RANKING MATRIX

	No consequence	Low consequence	Medium consequence	High consequence
High likelihood				
Medium likelihood				
Low likelihood				

BPWORKS is a multiprogram software application that stores a wide range of information related to buried piping systems. It is used to perform risk rankings of piping systems. Risk ranking is based on over 50 specific design and operating attributes in each major plant piping system in combination with inspection results, failure history and mitigation steps. Results can be adapted for user needs by adjusting risk based weighting factors around key criteria such as safety, environmental factors or power generation. The end result is a relative risk rating and mapping for each major piping system. The programme looks at the likelihood of ID initiated leaks, breaks or occlusions and OD leaks or breaks [318].

MAPPro is a family of applications that link to BPWORKS and allow users to perform internal and external corrosion based risk ranking of buried piping, tanks and other structures not currently addressed in BPWORKS. Users can import, trend and visualize high volumes of data associated with CP, soil testing, tritium monitoring wells and inspection data (UT, guided wave ultrasonic testing (GWUT), etc.). A module also covers low and medium voltage cables and part of a cable ageing programme [319].

COMSY is a general application software program for ageing and plant life management of piping (not specifically buried) that allows for degradation mechanism risk assessment from such mechanisms as MIC, general corrosion, SCC and FAC. It does not specifically incorporate the existence of CP into the degradation evaluation.

Typical risk ranking steps are as follows:

- (i) Include all systems with underground structures in scope and evaluate via selected risk ranking tool/ methodology;
- (ii) Rank underground structures on basis of risk to correctly characterize vulnerabilities;
- (iii) Use information collected in data gathering phase and separate systems into discrete segments (mainly applicable to underground/buried pipes). Suggested locations to start a new segment are:
 - (a) Pipe transitions from above to below ground level;
 - (b) Changes in internal or external load conditions (pipe under a road);
 - (c) Changes in soil properties, if known;
 - (d) Changes in coating or CP;
 - (e) Changes in pipe material;
 - (f) Changes in pipe diameter;
 - (g) Tees, branches, weldolets.
- (iv) Evaluate each underground segment (or structure) to identify potential causes of failure such as: corrosion, erosion, internal and external loadings, mechanical defects, lining degradation (if applicable) and occlusion;
- (v) Determine likelihood of failure (low, medium, or high) for each underground segment (or structure);
- (vi) Determine consequence of failure for each underground segment (or structure) failure mode;
- (vii) Rank risk for each underground segment (or structure) to assist in prioritization of inspection;
- (viii) Document ranking results in AMP database.

See Fig. 86 for an example of a typical pipe segmentation.

Summary results can be displayed in a format such as the risk ranking matrix in Table 22 with high consequence/high likelihood pipe segments being a priority for inspection.



FIG. 86. Segmented pipe.

5.5. PROGRAMME DEVELOPMENT

5.5.1. Assignment of programme owner

The development, implementation and maintenance of an underground structure integrity and asset management programme help to ensure nuclear safety, equipment reliability and environmental compliance. A programme owner in an operating organization is typically appointed to develop required programme governance, provide oversight, document the AMP (including screening/risk ranking methodologies) and monitor compliance. Depending on the size of the operating organization other individuals may be involved with detailed programme activities, such as planning for and executing inspections (Section 5.5.2) and site specific reporting (Section 5.7.2).

5.5.2. Inspection planning

A key part of programme development is the preparation of an inspection plan. The purpose of the inspection plan for underground structures is to provide reasonable assurance of structure (pipe, tank, etc.) integrity and that it will be maintained in good order between successive inspections. Inspection priorities are developed based on risk rankings performed (Section 5.4), station work management processes, OPEX, other planned work for the applicable time period, resource availability and programme budgets.

5.5.3. Staff qualification and training

Staff qualification (defining required training to ensure qualified and competent engineering and inspection staff) is important. Staffing is a sensitive issue for nuclear operators globally and is more difficult when considering specialized areas such as buried piping and CP support. A long period of time is necessary to develop qualified staff and required courses may be run only infrequently or may not even be available in certain jurisdictions. Staff turnover can lead to the need to replace qualified staff.

There are many international guidelines as to the appropriate level of staffing for efficient operation of different component and equipment engineering programmes such as EPRI's Ref. [320]. To determine acceptable staffing requirements for buried piping and underground tank management, it is essential for nuclear operators to understand the issues involved and integrate them with plant equipment reliability initiatives.

A qualified engineer to execute the buried and underground piping and tank AMP is expected to have sufficient knowledge of corrosion mitigation practices, coating methods, CP systems and soil analysis. A period

of one to two years job shadowing, while completing course work, is recommended for a candidate engineer in training. There are specialized courses developed by subject matter experts such as EPRI and NACE that can be adopted by utilities as part of their qualification packages. An IAEA guide for training of nuclear power plant staff is available, IAEA Safety Standards Series No. NS-G-2.8 [321], as well as specific training guidelines for certain NDT techniques [322]. ISO has also issued a standard for qualification and certification of NDT personnel [323].

It is recommended that nuclear operating organizations, given their specific circumstances, perform a typical job task analysis and prepare a task to training matrix to identify the gaps in training required to develop a buried piping and underground tanks ageing management specialist. There are many utilities that have gained substantial pioneering knowledge in this field. Operating organizations are encouraged to benchmark their buried and underground piping and tank AMP versus industry best practices, including training and qualification aspects.

5.6. PROGRAMME DOCUMENTATION

AMPs are required to be clearly documented. They are living programmes and should be reviewed periodically, updated when more plant data become available and kept up to date as industry knowledge and new technology evolve.

A sample overview of typical contents for a documented programme is listed in Table 23.

Utilities are advised to document risk ranking results and create and maintain a controlled database for underground structures. Such data are critical in determining the scope of the programme and must be well documented and retrievable for reviews or audits.

TABLE 23. SAMPLE TABLE OF CONTENTS FORA BURIED PIPING PROGRAMME DOCUMENT

Sample programme document content for a utility		
Programme objectives		
Programme scope		
General requirements		
Staff qualifications		
Utility working groups		
Self-assessments		
Health reporting		
Specific requirements		
Risk ranking		
Inspection		
Indirect inspections		
Direct inspections		
Inspection reporting		
Design disposition		
Repairs and/or replacements		
Corrective actions		
Station strategy manual		
Roles and accountabilities		
Records and documentation		

5.7. COORDINATION MECHANISMS

5.7.1. Organizations and programmes involved

Different organizational units at a nuclear power plant have important roles to play within a successful AMP. Experts from operations, engineering, equipment qualification, design and research and development should be

participants in the ageing management team. Other plant programmes can also have key roles to play; for example a plant's fire protection programme can be used to detect piping degradation in fire related piping systems. A general pressure vessel or tank inspection programme can address some issues related to underground tanks (e.g. programme requirements under ASME Section VIII⁷). Groundwater monitoring programmes can detect large leaks.

Changes to other station programmes can have impacts on the buried piping programme. For example, changes in chemistry programme requirements can impact on pipe degradation rates. Changes to such programmes need to be shared with other programme owners in an integrated fashion.

Programme overlaps and gaps need to be understood and addressed. Reference [3] recommends documentation of the policies and objectives of establishing an AMP, designation of an ageing management coordinator (the programme owner of Section 5.5.1) and documentation of team responsibilities and interfaces.

5.7.2. Reporting recommendations

System or component health reports are useful tracking and trending tools to monitor the implementation and sustainability of component programmes. They are an effective mechanism to communicate to executives, stakeholders and regulators overall programme status, including ratings against established performance indicators. Regular reviews and oversight by senior managers help to ensure such programmes receive appropriate support from within the operating organization.

Reporting format, health indicators and targets are typically defined by the programme owner and benchmarked with industry best practices. A sample health report for a buried piping programme is given in Appendix VI. It must be noted that health indicators may differ among operators depending on the maturity of the programme and special local circumstances.

For multiunit nuclear power generators, these reports are often initiated at a site level and then rolled up into a fleet view report for presentation to senior nuclear executives. The frequency of producing these reports is typically determined by the programme owner at the corporate level.

As indicated in Sections 5.3 and 5.6, a standardized database that records piping section and tank history is useful in support of effective monitoring and reporting.

5.8. IMPROVING PROGRAMME EFFECTIVENESS AND OPTIMIZATION

It is important to note that an AMP is not a static programme. As was illustrated in Fig. 2, it should be periodically reviewed and updated to reflect internal and external OPEX. Depending on plant performance, this may lead to either increased or reduced inspection intervals, or other changes in approach. In addition, continued evolutions in safety thinking and developments in current knowledge and technology relating to both piping durability and assessment techniques should be incorporated.

AMPs can be improved and optimized with the assistance of self-assessments and peer reviews, which should be a regular part of any buried piping AMP. Peer reviewers can be from within an operating organization, from similar plants or from other operators or industries that use underground piping.

Appendix IV provides information on AMP practices in a number of Member States, Appendix V provides non-nuclear OPEX related to tanks and piping, while Appendix VI provides a sample health report format used by an operating organization.

⁷ ASME International, "ASME Boiler and Pressure Vessel Code, Section VIII — Pressure Vessels, BPVC-VIII- 2015", ASME Boiler and Pressure Vessel Code, ASME International, New York (2015).

6. MANAGING AGEING MECHANISMS DURING PLANT OPERATION

Plant operation has a significant influence on the degradation rates of nuclear power plant SSCs. Accordingly, operational staff should maintain operating conditions within prescribed design limits to ensure that the effects of any associated degradation mechanisms are minimized. For buried piping this is normally achieved through adhering to technical specifications, chemistry control and system monitoring procedures and processes.

6.1. OPERATING ACCORDING TO PROCEDURES AND TECHNICAL SPECIFICATIONS

Exposure of systems, components and structures to operating conditions (e.g. temperature, pressure, humidity, radiation and aggressive chemicals) outside design limits can lead to accelerated ageing and degradation. Since operating practices influence operating conditions, nuclear power plant operations staff have an important role within the AMP to minimize age-related degradation by maintaining operating conditions within designated design limits. For buried piping and related components operations staff have limited influence as they have little or no control over the external environment surrounding the buried plant. However, they can influence the risk of internal degradation by maintaining fluid parameters within identified designated limits.

Stagnant pipe sections should be designed out of installations. However, if this is not practical then operational procedures should be implemented to limit the potential of stagnant fluids on ageing and degradation.

Some issues with nuclear power plant cooling water systems are associated with providing diversity and redundancy and with sizing systems to accommodate design basis accident (DBA) conditions (as opposed to normal operation) in which actual heat loads are greater. As a result, many systems spend half of their lives or more in what is essentially wet lay-up. Further, when those systems do flow, they flow at very low rates at which suspended solids and microbes can deposit on surfaces and produce corrosion conditions that are well outside of those for which the system was constructed.

This section will address methods for treating intermittent use systems, provide guidelines for minimum flows and flow frequencies and offer recommendations for the elimination or minimization of dead legs. EPRI's service water piping guideline [91] contains more detailed discussions on these topics.

6.1.1. Effects of operation and flow on corrosion

Many nuclear power plant buried piping systems are subject to a variety of operating conditions that affect degradation from the ID. These conditions can vary significantly with time and can include numerous periods of flow stagnancy. Because safety related systems are designed for most limiting conditions (e.g. a loss of coolant accident), their much lower normal heat loads will require much lower cooling water flows during most periods of operation.

As a result, duplicate or triplicate paths will exist for cooling water such that one, two or three legs of the system will be filled with cooling water, but in a standby mode, awaiting a need for cooling of equipment. All of those systems, however, will be operated periodically for testing on a regular basis. For many portions of SR service water systems, periodic operation, interspersed with extended periods of wet lay-up, will be the most common condition of operation. Those changes in flow conditions can dramatically change the nature of the degradation that the piping will experience by producing local conditions that are significantly different from those that were considered in design.

6.1.1.1. Normally flowing conditions

Corrosion allowances for cooling water and fire protection system piping are typically based upon 40 years of operation assuming design flows and temperatures and a standard water chemistry. Typical fluid velocities may range from less than 0.3 to 3 m/s. Most often, normal flows produce fluid velocities of 0.9 to 2.1 m/s.

Under normal flow conditions, uncoated CS or cast iron will degrade by general corrosion that produces a protective oxide film. The form and rate of the corrosion will be determined by how protective the oxide actually is. The composition and protective nature of that oxide will be a function of dissolved oxygen, temperature, flow and water chemistry.

Normally flowing lines will form a relatively uniform and fairly protective oxide and may form some tubercles. In flowing environments, at temperatures and water chemistries typical of cooling water systems, the corrosion is most often general corrosion at fairly predictable rates where the greatest amount of general corrosion will occur in those flowing pipes.

The presence of corrosion products would also be expected to produce a small loss of flow carrying capability over time due to a slight reduction in cross-sectional area and an increase in roughness. Those effects may or may not have been accounted for in the design.

6.1.1.2. Normally stagnant conditions

Many nuclear power plant systems will have a number of legs that will be stagnant for extended periods ranging from weeks to months, may flow half of the time or less and may only flow for a few hours during testing. In normally stagnant systems, oxygen, the primary constituent that controls corrosion, will be consumed relatively quickly by corrosion reactions and biological oxygen demand.

As a result, general corrosion will proceed to a very limited extent, decrease as water oxygen content decreases (corrosion rate will be directly proportional to oxygen content) and eventually stop as the oxygen is consumed. However, MIC can proceed, driven by anaerobic organisms such as sulphate reducing bacteria. This produces localized corrosion at much greater rates than those of general corrosion under anaerobic conditions and may approach or even exceed corrosion rates considered in corrosion allowances. In addition, films that are established during periods of stagnation can produce accelerated corrosion if and when oxygen is introduced.

6.1.1.3. Intermittent flow conditions

Portions of many buried piping systems cycle between periods of stagnation and periods of flow at a variety of flow rates, based upon varying cooling demands, from rotating flow time between parallel legs, or from periodic testing.

Intermittent flow conditions usually do not produce degradation that is intermediate between that of the normally flowing and normally stagnant legs (e.g. time averaged based upon the fraction of time flowing). In many situations, corrosion is worse than that from either full flow or stagnant conditions. When the environment and time period of stagnation are such that they reinforce aggressive conditions during flow periods following the stagnation periods, extremely rapid degradation can occur that has not been considered in design.

For example, biofilms formed during extended periods of stagnation may have only minimal effects on corrosion during stagnant periods but can establish conditions that will produce very rapid corrosion during the transition from stagnation to full flow. The bulk of such corrosion will occur at high rates for minutes or hours during the transition from anaerobic and stagnant conditions to full flow in aerated water.

6.1.1.4. Dead legs

A number of dead legs may exist because of the extent of piping in nuclear power plant systems. A dead leg is a normally stagnant branch connected to a normally flowing leg. Dead legs may also be connected to intermittent flow legs, but would only be a dead leg when the intermittent flow leg was actually flowing. Degradation that occurs can often be the worst in the piping system, depending upon materials, environment, flow rates in the flowing section, relative sizes of piping in the flowing pipe and dead leg and dead leg length and orientation. The distance over which oxygen penetrates into the dead leg, local flows and collection of other debris, including formation of biofilms on surfaces, can all influence the degree of localized attack.

Fluid flow in lines running past the stagnant lines will cause some turbulence at the tee and mixing of otherwise stagnant fluid in the dead leg. In truly stagnant systems without water replenishment, general corrosion reactions and biological oxygen demand consume available dissolved oxygen in a matter of days. Once oxygen is removed, all non-biologically driven corrosion stops. However, because of turbulent water flow into the dead

leg sections during flow periods, dissolved oxygen will be replenished in pipe sections that would otherwise be considered stagnant. In fact, with quiescent, oxygen-rich water within the dead legs, MIC activity should be expected to increase without water flow that scours microbial colonies from piping walls and pitting propensity should increase with no heavy flow to wash out concentration cells.

When dead legs are modelled this way, the same general corrosion rates are predicted as are observed in continuous flow situations as there is no dissolved oxygen restriction. Further, pitting susceptibility will be greater since communication between anodic and cathodic areas will be limited by the lower flows. Finally, MIC susceptibility will be higher since there is no scouring action of flow, but cathodic reactions from oxygen reduction will not be decreased.

6.1.2. Beneficial system operational changes

Modifications to the operation of buried piping systems can have significant positive effects on ID piping corrosion. For example, changing flow schedules for intermittent flow systems can significantly improve control capabilities. More frequent flow can serve to prevent microbial attachment and will introduce water treatment chemicals to the non-flowing train more often to improve corrosion control. Modifications to the flow schedule must consider the entire system, not just the piping.

Full flow or side stream filtration can provide an effective and economical method for removal of silt, other suspended solids, corrosion products and macrofouling organisms that produce crevices and under-deposit corrosion conditions. Elimination or reduction of constituents that can produce deposits and aggressive under-deposit conditions can produce an effective improvement in piping performance.

Filters may permit shock dosing systems with chemicals to remove large quantities of foulants from piping surfaces. Filters provide locations for foulants to be collected and removed. Without a filter, deposits that are removed can collect in other critical spots where their presence can severely impact on a system.

Many plants use thermal treatments to control macrofouling organisms. Typically, a few additional valves and small lines are provided that permit discharge side flows to be directed to inlet screens and piping. Thermal treatments can also be effective for microorganisms; however, the temperatures that must be used are higher than for macro-organism control, often requiring external heat sources.

6.2. CHEMISTRY CONTROL

Chemistry control of contained fluids assists in reducing degradation from inside of components. Corrosion inhibitors can be effective in minimizing internal degradation in closed loop systems. Biocides, surfactants and biodispersants can be effective in preventing fouling, attachment and growth of microorganisms for raw water piping. Where these systems are open loop systems, restrictions on chemical discharges are generally applicable and post-treatment may be necessary.

Chemistry control of the external environment of buried piping is not a practical option; however, knowledge of external conditions is critical to understanding the corrosion potential for the pipes or tanks in question. The normal mitigation method for external corrosive environments is through the application of barrier coatings.

6.2.1. Water analysis

Most nuclear power plants routinely collect water samples from process streams (e.g. service water, cooling water, fire systems and raw or treated water used for plant make-up).

Water sampling and analysis assist in determining the degradation potential of underground piping from the ID (which will be additive to OD degradation) and assessing the performance of chemical treatment programmes designed to minimize corrosion, microbiological fouling and scale/deposition. It is necessary to develop and follow standard procedures to ensure that samples are representative of the process stream, information necessary to characterize the sample is obtained, external contamination is minimized and proper preservation is utilized.

Samples typically need to be obtained from pressurized pipes or closed conduits, but there are no universal sampling procedures. Samples can be collected by taking discrete grab samples, or by obtaining samples over a

specified period of time. Particulate sampling (collected on filter pads and/or ion exchange filters) may be utilized for measuring trace level metals in high purity water applications.

Grab samples are single samples collected from an individual location at a specific time and thus represent only a 'snapshot'. A small portion of the process stream is obtained and used to characterize the entire process. When the process stream is known to vary over time, discrete samples may be collected over a longer interval and statistical data evaluation can be performed to determine representative process quality. Continuous monitoring may also be done for pH, conductivity, specific ions, and so on using instruments that are inserted into the flow or a side stream.

Composite samples provide a more accurate representation of heterogeneous process streams. Composite sampling may consist of collecting a series of individual samples and integrating them into a single sample or using an automated sampler that collects samples at regular intervals as defined by a programmed sequence schedule. Composite sampling is not recommended for some constituents that can change over time such as oil and grease, pH, temperature, dissolved oxygen and volatile organics.

6.2.2. Water treatment

There are a large number of processes that circulate water in a nuclear power plant in piping. Deposition, fouling and corrosion of inner pipe diameters may adversely impact on system performance and if not properly treated and monitored may result in damage and ultimately pipe failures. A comprehensive chemical treatment programme may be necessary to mitigate these effects in systems where treatment can be applied.

Chemical treatment programmes are commonly utilized to control corrosion (deposition, scaling and fouling) and microbial growth, which can lead to MIC. The programme should be based on the quality and variability of the make-up and circulating water. Corrosion inhibitors are selected to protect materials in the system and may be comprised of cathodic inhibitors, anodic inhibitors or a combination of both. Deposition is normally associated with preventing calcium carbonate formation but may also address other compounds such as calcium phosphate, calcium sulphate or magnesium silicates. Microbial growth is often controlled through addition of oxidizing and/ or non-oxidizing biocides. Oxidizing biocides may be fed on a continual basis at a lower dose, or intermittently at a higher dose. Non-oxidizing biocides are typically batch fed.

6.2.2.1. Chemical treatment

Once-through water systems in nuclear power plants use water in a single pass and are discharged directly; a cooling tower is not used. In open recirculation systems, water is used multiple times; heat is rejected in a cooling tower, sprays or via other processes. Chemical treatment options for open systems require greater chemical usage and attention than treatment of closed loop systems.

In all systems, minimizing corrosion, deposition and scaling and biofouling typically requires chemical treatment and operational controls. Chemical additives are designed for a given application and system metallurgy. Most open systems may require the use of four classes of chemicals that consist of corrosion inhibitors, deposit control agents or dispersants, antimicrobials and pH adjustment chemicals. Blowdown of open recirculation systems is an integral part of the process as it removes dissolved and suspended solids. Treatment of a once-through system will generally be less effective than treatment of an open recirculation system of the same basic water chemistry and will require greater amounts of chemical addition to achieve the same levels of effectiveness.

6.2.2.2. Corrosion control

Controlling corrosion requires either changing the metal so that it will not corrode in the given environment, which is often an expensive and impractical alternative, or changing the environment to inhibit the corrosion process. Modifying the environment for a water system can be accomplished by forming a protective film at the metal surface by the addition of corrosion inhibitors. Scales (e.g. calcium carbonate) can also provide a level of corrosion protection for CSs.

In most plant water systems, the most common approaches are to use corrosion inhibitors or deaerate the system. Corrosion inhibitors are designated as anodic or cathodic, depending upon whether reactions are blocked at the anodic or cathodic corrosion sites.

6.2.2.3. Scale and deposit control

Scale deposits are a result of precipitation and crystal formation where the solubility of certain species is exceeded in water or at its surface. Some examples in cooling water application may include calcium carbonate, calcium phosphate, calcium sulphate and magnesium silicate. These compounds exhibit retrograde solubility in that they are less soluble at higher temperatures and tend to precipitate on heat exchanger surfaces and downstream piping.

Factors that play a role in scale formation are water quality, pH, temperature, cycles of concentration in cooling systems and holding time. Once scale is formed it provides a site for additional crystal growth that can occur at a more rapid rate [91].

Fouling occurs when insoluble particulates suspended in water deposit on surfaces. These materials may enter the system from make-up, airborne contaminants, or raw water treatment chemicals (aluminium and iron). Polymers can provide good scale control inhibition as well as keep suspended solids in the water.

6.2.2.4. Biological control

Chemical treatment to control biological growth is classified into oxidizing and non-oxidizing biocides [324]. An effective treatment programme and choice of biocide takes into account the system to be treated, water analysis, organisms to be controlled and environmental impact.

Increasingly, bivalves such as zebra mussels have been a reported concern for nuclear power plants. Impacts can include clogging of pipes, screens, condensers and heat exchangers, reductions in efficiency and increased erosion and corrosion. Systems using raw water or raw water make-up (water intakes, service water, fire systems, etc.) are particularly vulnerable, especially during lay-up periods if they are not emptied and dried. Chemical treatment is normally needed at both intakes and discharges during applicable growing seasons.

Systems have also been developed for electrolytic biological control of organisms such as barnacles, limpets, mussels and tubeworms. The tank system shown in Fig. 87 has electrodes contained in a tank through which a flow of water is passed and then fed to the pump intake. The water becomes treated with copper/aluminium ions in the tank and the discharge of this treated water gives antifouling protection to the downstream pump(s).



FIG. 87. Cuprion system for biological control using ions (courtesy of Cathodic Protection Co. Ltd.) [325].

6.3. ENVIRONMENTAL CONTROL

A number of potential environmental changes need to be considered in relation to buried piping and tanks. These are extremes of environmental temperature, flooding/water table, soil resistivity and external loading. Each will be discussed in turn.

6.3.1. Extremes of temperature

It is unlikely in most circumstances that buried piping and components would be directly subject to degradation by extremes in environmental temperatures. However, where it is considered prudent to provide mitigation for this type of environmental event, extremes of low temperatures are judged to be the only credible scenario. Mitigation under these circumstances would be the use of insulation, either on its own or in combination with trace heating.

6.3.2. Flooding and water table changes

Flooding or a high water table could result in a buoyancy effect on the piping or components. On its own this should not have a direct effect on the potential for degradation; however, the fact that the surrounding soil is wet will provide a more favourable environment for corrosion activity.

6.3.3. External loading

External loading may be of concern where piping is routed under roadways, railroads or other sources of repetitive loads such as those encountered during construction activities. Operating activities such as heavy lifts or heavy equipment movements may also be of concern. While normally accounted for in designs, changes in loading or land use can impact on piping degradation where sufficient margins to accommodate them have not been incorporated into the design.

Damage from excavation-related activities, particularly equipment digging into pipelines, can be a cause of pipeline accidents. For nuclear power plants, knowing the exact location of buried piping routes (see Section 8.2.1.1) is key to avoiding such problems. When locations are known, activities in the applicable areas can be assessed and planned to minimize impacts on the piping system. Operating organizations may consider placing restrictions on activities above critical piping.

6.3.4. Soil condition

Nuclear power plants regularly collect water samples from water systems (e.g. circulating water, service water, ESW, fire protection), but infrequently collect soil samples. Soil analysis includes identifying sampling locations, sample handling, parameters to be measured, analysis of samples and discussion of monitoring tools.

Soil is generally composed of three types of materials — clay, sand and silt, as shown in Fig. 88. There is no consensus definition for a corrosive soil; however, a commonly used standard is AWWA C105 [327], which evaluates soil corrosivity by a point system as shown in Table 24. Soils with more than ten points are considered corrosive. Note that resistivity is the major parameter in the evaluation. Another commonly used method uses only soil resistivity, as shown in Table 25. In this methodology measured values of $< 5 \Omega \cdot m$ are judged to be highly corrosive while values of $> 20 \Omega \cdot m$ are benign.

Sand, or a mixture of sand and gravel, will provide a less corrosive environment (better drainage and higher resistivity) than clay, silt or loam. Tables 24 and 26 identify soil parameters that have an effect on the corrosion process.

Experience has shown that prediction methods for soil corrosivity as given in Tables 24 and 25 provide general guidance on soil corrosion. Soil corrosion is a more complex process that generally requires collection of more specific data and analysis.

For concrete pipe, Ref. [34] identifies environments with high chloride or sulphate content, acid conditions or dissolved CO_2 in groundwater (produced from rainwater or humic acid from vegetation decay) as being aggressive to PCCP. Protective measures or supplemental corrosion protections are generally recommended for pipes located



FIG. 88. Soil composition of three types [326].

in soils containing resistivity below 15 Ω ·m and more than 400 ppm water-soluble chloride at the same location, soils containing over 2000 ppm sulphates, or soils with pH below 5.

6.4. OPERATING HISTORY, INCLUDING TRANSIENT RECORDS

Record keeping of relevant operational data (e.g. environmental conditions, test conditions and results) is also essential for an AMP. In particular, it is prudent to attempt to control and monitor the operating environment of piping such as that encased in the concrete basemat of a building, where detection and repair of degradation would be difficult and costly.

Major transients and events (e.g. impacts, seismic events, fires, chemistry excursions, severe weather and all modifications) should be recorded and evaluated at time of occurrence and kept as part of system records.

Parameter	Value	Points*
Resistivity	< 15	10
$(\Omega \cdot m)$	≥ 15–18	8
	> 18–21	5
	> 21–25	2
	> 25-30	1
	> 30	0
Η	0–2	5
	2-4	3
	4-6.5	0
	6.5–7.5	0**
	7.5–8.5	0
	> 8.5	3
Redox Potential	>+100 (mV)	0
	+50 to +100 (mV)	3.5
	0 to +50 (mV)	4
	Negative	5
Sulphides	Positive	3.5
	Trace	2
	Negative	0
Moisture	Poor drainage, continuously wet	2
	Fair drainage, generally moist	1
	Good drainage, generally dry	0

TABLE 24. AWWA C105 SOIL CORROSIVITY INDEX

(Appendix A from Ref. [327], notes on procedures for soil survey test and observations and their interpretation to determine whether PE encasement should be used)

* Soils with more than ten points are considered corrosive; protection is needed.

** If sulphides are present and low or negative redox potential results are obtained, add three points for this range.

Resistivity (Ω·m)	Soil corrosivity (description)
Below 5	Very corrosive
5–10	Corrosive
10–20	Moderately corrosive
20–100	Mildly corrosive
Above 100	Progressively less corrosive

TABLE 25. SOIL CORROSIVITY VERSUS RESISTIVITY [328]

TABLE 26. SOIL EFFECTS ON CORROSION PROCESSES

Anodic (active)	Cathodic (noble)
Low oxygen	High oxygen
Low resistivity	High resistivity
Sulphate reducing bacteria	No sulphate reducing bacteria
Water saturated	Generally dry condition
Organics	Clean soil (inorganic)
Conductive (coal, cinders)	Clean soil

7. INSPECTION, MONITORING AND ASSESSMENT OF UNDERGROUND PIPING AND TANKS

7.1. BACKGROUND

It is difficult if not impossible to inspect buried piping or tanks to determine if degradation is occurring from the soil side. In addition it can be very difficult to undertake meaningful inspection from the inside of buried piping which would provide evidence of the condition of the external surface. In many cases the only practical solution is to monitor the components/systems. Regular plant walkdowns should be undertaken in which the route of buried systems is walked down looking for evidence of leakage. Where buried systems have make-up tanks, water meters or pressure gauges fitted these can also be monitored to determine changes in the system conditions which might provide additional evidence of any leakage or other adverse condition.

When buried piping leaks, the leak source can be difficult to locate, access and repair. Breaches in buried piping can present challenges to nuclear safety. In addition, leakage from buried piping containing radioactive or other hazardous fluids presents an uncontrolled environmental discharge which could be in breach of a site licence.

Inspection, surveillance and condition assessments are essential elements of an effective AMP. Knowledge gained from these activities can serve as a baseline for evaluating the safety significance of any damage and defining in-service inspection programmes and maintenance strategies.

Inspection and surveillance activities are designed to detect and characterize significant component degradation before fitness for service is compromised.

Surveillance activities are typically those performed by operations and engineering staff as part of plant walkdowns and review of inspection, maintenance and testing records. Inspections are those activities that are typically scheduled routinely to evaluate in detail the condition of a particular SSC on the basis of defined acceptance criteria.

7.2. TESTING AND CALIBRATION

Pressure testing is an acceptable method of proving the integrity of buried pipework and tanks. To provide meaningful results it is essential that testing is undertaken at a pressure above the maximum operating or design pressure. While this process can provide assurance that there is a design margin against failure of the pipework, it can also exacerbate existing degradation effects. There can be practical problems such as achieving leaktight isolations, fluid compatibility, environmental temperatures and leak rate acceptance standards in implementing a hydrostatic test.

7.3. PRE-SERVICE AND IN-SERVICE INSPECTION (AND MONITORING)

Together with an understanding of piping/tank degradation, inspection and surveillance results provide a basis for decisions regarding the type and timing of maintenance actions to correct detected ageing effects.

Inspections are designed to provide reasonable assurance that structures (pipes, tanks, etc.) are intact (leakage integrity) and will be maintained in good order between successive inspections.

A management plan should be developed which determines the investigatory approach to be adopted. Priorities for inspections would be per risk assessments as described in Section 5.4. This plan could include indirect inspections or surveillance for the high risk piping, so that a more informed indication of the actual condition of the piping and plant could be provided. Indirect investigations need not be restricted to high risk plants; however, it is judged that medium and low risk could be accepted on the basis that reactive mitigation measures are sufficient to provide 'reasonable assurance' of its condition.

7.3.1. Inspection methodology

Many inspection techniques are available; however, the pros and cons of each method have to be weighed before carrying out an inspection. Inspections may be indirect (without having direct access to the affected pipework or tank) or direct (being in immediate contact with or close proximity to the affected pipework or tank) [329]. Direct inspections can also be done on the outside pipe or tank surface or the inside surface. Due to the cost of excavation and technical limitations it is often beneficial to use a combination of methods, with, for example, indirect inspections being used to select optimal locations for more targeted direct inspections. In some cases piping may only need partial excavation (e.g. exposing the top of the pipe) to perform an adequate direct inspection. Where technically justifiable, selection of excavation locations that provide opportunities to inspect multiple pipes, or locations that may be outside of the plant controlled boundary, can provide significant programme cost savings.

Examples of indirect inspection methods include over-the-line surveys, close-interval surveys and others. Examples of direct inspection methods include visual inspection, ultrasonic testing, eddy current, radiography and various electromagnetic techniques. Specifics of these inspection techniques will be discussed in Sections 7.3.2 and 7.3.3.

Some issues to consider are the following:

- Inspection goals (detect presence of defects, size of defects, CP system assessment, etc.);
- Adequacy of visual inspections to assess components;
- Need for direct examination;
- Feasibility of completing inspection from outside of pipe or with a partial excavation.
It is important to know the accuracy, sensitivity, reliability and adequacy of the non-destructive methods used to identify and evaluate the particular type of suspected degradation. Inspection methods must be evaluated to be able to rely on their results, particularly in cases where they are used as part of fitness for service assessments. Table 27 has been adapted from a number of sources (e.g. table 2 in Ref. [8] and table 3.3 in Ref. [330]) and provides a summary of available technologies, limitations and other properties for the NDE techniques covered by this publication.

7.3.2. Indirect inspections

Utilities may use a variety of available techniques to perform surveys and assess the likelihood of degradation prior to or without direct inspections.

Over-the-line surveys can provide valuable information on the integrity of pipe coating, potential significant wall thinning, insufficient CP, or other irregularities without a need for trenching or digging for direct access to the underground segment or structure.

Some of the currently available and recommended indirect inspection techniques are:

- Soil testing.
- Ground penetrating radar.
- Voltage gradient tests:
 - DCVG;
 - ACVG;
 - Pearson surveys;
 - CIPS;
 - Pipe-to-soil potential survey;
 - Cell-to-cell potential survey;
 - Area potential and earth current (APEC).
- AC current attenuation (ACCA):
 - C-scan;
 - Pipeline current monitor.
- Magnetic tomography.
- Leak testing:
 - Visual methods (walking the line and bubble testing);
 - Acoustic;
 - Hydraulic;
 - Chemical tracers;
 - Remote sensing;
 - Groundwater monitoring;
 - Preinstalled systems.

Each of these is covered in the following sections and is listed in Table 27. It is important to know the accuracy, sensitivity, reliability and adequacy of the NDT methods used to identify and evaluate the particular type of suspected degradation. Inspection methods must be evaluated to be able to rely on their results, particularly in cases where they are used as part of fitness for service assessments.

Underground structure engineers may establish periodic indirect inspection schedules and document the technical basis in the site strategy manual. Indirect inspections/over-line surveys should be performed by qualified/ certified personnel.

7.3.2.1. Soil testing

Surveys of soil resistivity and soil chemical analysis can be used to identify areas where environments may be corrosive, or to evaluate whether native soils are suitable for backfilling excavations. Refer to Section 6.3.4 for details regarding soil condition parameters.

Text cont. on p. 181.

Technology name	Uses	Limitations	Cost	Sections of this document
Walking the line (usage: high)	Identify potential leak sites for further investigation Can be part of routine surveillance (low cost, often convenient)	Subjectivity of observer (unless leak is obvious) Leak detection is subject to noise from surrounding environment Cannot detect leaks in pipes under deep soil cover	Ś	7.3.2.6(a)
Soil resistivity and chemical analysis (usage: high)	Assessment of soil and groundwater corrosivity Can be used as a first step in risk ranking/condition assessment either to prioritize sections for assessment or to identify areas for more detailed inspection	Does not provide direct information regarding level of distress Depends on soil moisture content (which can seasonably vary) and cannot be performed on dry soil Requires access to ground surface above pipeline (for soil) and local excavation or boreholes (for groundwater and deeper soil)	<pre>\$ (for ground soil resistivity) \$ to \$\$ (for groundwater and deep soil samples closer to pipe)</pre>	7.3.2.1
Ground penetrating radar (GPR) (usage: low)	Area surrounding a potential leak site Determining location of buried pipework and other structures Can be used over long lengths of pipeline Can be used to locate position or rebar and embedded objects in concrete	Unlikely to be useful for detecting leaks Knowledge of typical depth of cover required Indirect technology requiring further investigation by other techniques	\$\$	7.3.2.2 7.3.2.6(e)
DCVG	Area surrounding a potential leak site Identifying sites of potential coating breaks (small to large holidays) Sometimes used to determine whether a region is anodic or cathodic, but cannot determine CP levels Can be used in combination with close interval potential survey (CIPS) (DCVG locates coating defects/holidays and CIPS analyses CP system) Can be deployed in areas with stray currents, near adjacent metal structures, near parallel pipelines, under AC transmission lines and in wetlands	Identified sites may not be associated with leakage points Not reliable under frozen ground, paved roads, rocky terrain, cased piping, for shielded corrosion activity or near river or water crossings Not reliable for anodic zones on bare pipe Signal required for detectable coating flaws increases as amount of grounding connected to piping increases Indications may be masked by adjacent coating holidays or structures	∽	7.3.2.3(a)

Sections of this docume	7.3.2.3(b)	7.3.2.3(c)	s pipe is 7.3.2.3(d) ntinuous)
Cost	\$	Ś	\$ (assuming electrically co
Limitations	Identified sites may not be associated with leakage points Not reliable under frozen ground, paved roads, rocky terrain, cased piping, for shielded corrosion activity or near river or water crossings Not reliable for anodic zones on bare pipe Signal required for detectable coating flaws increases a amount of grounding connected to piping increases Indications may be masked by adjacent coating holidays or structures	Identified sites may not be associated with leakage points Not reliable under frozen ground, paved roads, rocky terrain, cased piping, for shielded corrosion activity or near river or water crossings Not reliable for anodic zones on bare pipe Not reliable adjacent to metal structures or near parallel pipelines ACVG tends to give better results	Not reliable under frozen ground, paved roads, rocky terrain, cased piping or for shielded corrosion activity Does not indicate severity of corrosion damage Requires pipe to be electrically continuous Can be affected by stray currents, other buried objects, burial depth and other factors impacting on soil resistivity Good for large coating holidays or other conditions that impact on CP system only Unable to detect corrosion at bottom of large diameter pipe Requires access to and electrical contact to
Uses	Area surrounding a potential leak site Identifying sites of potential coating breaks (small to large holidays) Sometimes used to determine whether a region is anodic or cathodic, but cannot determine CP levels Can be deployed in areas with stray currents, near adjacent metal structures, near parallel pipelines, under AC transmission lines and in wetlands	Area surrounding a potential leak site Identifying sites of potential coating breaks (but cannot differentiate size of each holiday)	Determines status of CP system (can be a follow-up to routine CP system monitoring) Detects areas where corrosion is likely Provides complete pipe profile Can be used in combination with DCVG (DCVG locates coating defects/holidays and CIPS analyses CP system) Can be used periodically to monitor changes
Technology name	Alternating current voltage gradient (ACVG)	Pearson surveys	CIPS (usage: medium to high)

Technology name	Uses	Limitations	Cost	Sections of this document
Pipe-to-soil potential	Area surrounding a potential leak site Identifying potential corrosion 'hot spots' Detects areas where corrosion is likely Can be used on concrete pipe to detect areas where wire corrosion from the external surface is most likely Can be used periodically to monitor changes	'Hot spots' may not be associated with a leakage point Requires pipe to be electrically continuous Can be affected by stray currents, other buried objects, burial depth and other factors impacting on soil resistivity Unable to detect corrosion at bottom of large diameter pipe Requires access to and electrical contact to ground surface above pipe and pipe itself Can be affected by coating delamination (which interrupts electric current) Requires removal of any surface dielectric coatings	\$\$ to \$\$\$ (depending on excavation cost)	7.3.2.3(e)
Cell-to-cell potential (usage: low)	Detects areas where corrosion is likely via ground surface measurements Used for pipes that are not electrically continuous Can be used periodically to monitor changes	'Hot spots' may not be associated with a leakage point Can be affected by stray currents, other buried objects, burial depth and other factors impacting on soil resistivity Unable to detect corrosion at bottom of large diameter pipe Requires access to and electrical contact to ground surface above pipe	\$ to \$\$	7.3.2.3(f)
AC current attenuation ACCA C-scan/ pipeline current mapper (PCM)	Area surrounding a potential leak site Detection of small coating holidays Can be deployed under frozen ground, in areas with stray currents, near adjacent metal structures, near parallel pipelines and in wetlands PCM can be used (along with coating assessment) to locate pipes and measure depth of cover (can be difficult with pipes connected to grounding elements)	May not detect very small coating pinholes Hindered by interference from AC power lines Not reliable for cased piping, anodic zones on bare pipe and shielded corrosion activity	\$ S	7.3.2.4

Technology name	Uses	Limitations	Cost	Sections of this document
Magnetic tomography method (MTM)	 Area surrounding a potential leak site Dimensional constraints from one manuafacturer: Pipe size: 56–1420 mm Pipe wall thickness: 2.8–22 mm Distance between magnetometer and pipeline max. 15 × pipe diameter 	Cannot detect defects which do not change stress field within material (i.e. blow holes, pitting) Hindered by interference from AC power lines Requires baseline readings when pipeline is free from significant degradation to obtain magnetic signature Not reliable for cased piping, anodic zones on bare pipe and shielded corrosion activity Hindered by interference from AC power lines	\$\$ to \$\$\$	7.3.2.5
Leak detection — general	General leak detection	Does not detect defects directly. Limited use in predicting future integrity	\$ to \$\$\$	7.3.2.6
Leak detection — visual	Can validate NDT results and allow check of pipe design parameters (where pipe parameters not known/not documented) Provides direct inspection of pipe distress Can allow for soil, groundwater and coating samples to be taken for investigation Allows access for other NDT methods (e.g. wire continuity testing for concrete pipe) Vacuum boxes are suitable for tank weld and liner inspections	Excavation required for external inspections	\$\$ to \$\$\$ (depending on excavation cost)	7.3.2.6(a)
Leak detection — acoustic	Identify and locate leaks with pipeline in service Can be deployed outside of pipe (ground level) to determine leak location and thus minimize excavation Can be deployed inside of pipes for greater sensitivity (free swimming or tethered) Long lengths of pipe can be travelled	Methods can be subject to background noise Sensitivity decreases with pipe size and distance	\$ to \$\$ (depending on the material used)	7.3.2.6(b)
Leak detection — hydraulic methods (usage: low)	Identify leaks using hydraulic methods such as mass-balance, pressure-flow deviation, hydrostatic testing, transient frequency analysis, etc.	Requires measurement devices/metering installed	9	7.3.2.6(c)

Technology name	Uses	Limitations	Cost	Sections of this document
Leak detection — tracers and dyes	A section of pipework suspected of having a leak Potentially very sensitive; may detect leaks from mechanical joints, etc.	Can only be used during an outage, when system has been drained Use of a chemical or radiotracer may require special approvals	\$\$	7.3.2.6(d)
Leak detection — remote sensing — thermography (usage: low)	Identify and locate leaks Can be performed over long lengths of pipeline to identify potential leak sites for further investigation Flash thermography can be used on tanks to evaluate structure soundness Infrared theromography can detect hot spots and missing insualtion on accessible tank surfaces	Indirect technology that requires further investigation to confirm presence of a leak Requires means to survey pipe from a high elevation, e.g. a helicopter	8	7.3.2.6(e)
Leak detection — groundwater monitoring	Radioactive material leakage and its transport	Detection can often be long after the fact	\$	7.3.2.6(f)
Leak detection — preinstalled systems	On-line detection of leaks in critical systems	Expensive to retrofit due to excavation cost	\$\$\$	7.3.2.6(g)
Visual — internal (usage: high)	Identify pipes with severe distress and close to failure Can be performed in conjunction with other internal methods involving access to pipe Often convenient; easy to use; portable; can be automated	Cannot identify pipes with low levels of distress Subjective (based on observer skill) Confined space procedures and dewatering required Direct estimate of degradation not produced (e.g. number of prestressing wires broken for PCCP pipe)	\$ to \$\$	7.3.3.1
Visual — external (usage: medium)	Can validate NDT results and allow check of pipe design parameters (where pipe parameters not known/not documented) Provides direct inspection of pipe distress Can allow for soil, groundwater and coating samples to be taken for investigation Allows access for other NDT methods (e.g. wire continuity testing for concrete pipe)	Removal of coating may be required Excavation required Pressure reduction may be required	\$\$ to \$\$\$ (depending on excavation cost)	7.3.3.1

Technology name	Uses	Limitations	Cost	Sections of this document
Liquid penetrant testing (PT)	Detecting surface flaws in a variety of non- magnetic metal and other materials Weld inspections Easy to use; portable	Limited to detection of surface breaking discontinuities Not applicable to porous material Requires access for pre- and post-cleaning Irregular surfaces may display non-relevant indications	S	7.3.3.2
Magnetic particle testing (MT)	Locate surface and slight subsurface discontinuities or defects Weld inspections Advantageous compared to PT in that it detects subsurface defects such as inclusions May be portable	Applicable only to ferromagnetic materials Insensitive to internal defects Requires magnetization and demagnetization of materials Requires power supply for magnetization Coating may mask indication Material may be burned during magnetization	\$ to \$\$	7.3.3.3
Ultrasonic (UT) — conventional	Thickness measurements Surface profile Surface metal loss Discriminate internal versus external surface loss Discontinuities Sensitive to cracks Can penetrate thick materials Can be automated	Not capable of detecting defects whose plane is parallel to direction of sound beam Requires use of couplant to enhance sound transmission Requires calibration blocks and reference standards Requires skilful and experienced operator Not reliable for surface and subsurface discontinuities due to interference between initial pulse and signal due to discontinuity	S	7.3.3.4(a)
Ultrasonic (UT) — phased array	Similar to conventional UT, but more flexible for changes in pipe/tank dimensions or weld profiles and for different scan patterns Allows detection of smaller defects/pitting than conventional UT	Similar to conventional UT	S	7.3.3.4(b)

Technology name	Uses	Limitations	Cost	Sections of this document
UT — guided wave UT (GWUT)	Area surrounding a potential leak site Detects surface metal loss, large cracks and large discontinuties Good for rapid scanning of relatively long runs of pipe Can access inaccessible locations (buried, insulated, coated areas) from a single location Can be used for on-line monitoring	Must have access to end of pipework. Can only inspect short lengths of pipework (< 15 m from end and not around bends) Effectiveness not always predictable until inspection performed Will not detect defects which are less than 9% of pipe cross-sectional area; cannot accurately gauge thickness or discriminate between internal or external wall loss Not yet developed for non-metallic applications	<pre>\$\$ to \$\$\$ (for initial set-up depending on excavation cost) \$ (for subsequent inspections if permanent collars left installed)</pre>	7.3.3.4(c)
UT — electromagnetic acoustic transducer (EMAT)	Similar to conventional UT, but does not require liquid medium couplant and only 1/3 of pipe circumference access is needed	Similar to conventional UT but does not require liquid medium couplant	\$	7.3.3.4(d)
Eddy current — conventional	Detection of surface and subsurface discontinuities Readily automated No special operator skill required Low cost Useful for accessible welds in tanks	Applicable only to conducting materials If used for ferromagnetic material, item must be magnetically saturated to minimize permeability effects Requires skilful and experienced operator Shallow depth of penetration	Ś	7.3.3.5(a)
Eddy current — array (ECA)	Similar to conventional EC, but provides increased probability of detection and speed at slightly increased cost	Usually application specific and can be limited to specific areas or geometries Software set-up is complex for initial set-up as compared to other techniques Solving an application usually requires more development than with a pencil probe Lower sampling rate due to multiplexing Higher initial investment cost	\$\$ \$	7.3.3.5(a)
Eddy current — broadband electromagnetic method (BEM)	Real time pipe profiling and wall loss determination	None specifically identified	\$\$	7.3.3.5(a)

Technology name	Uses	Limitations	Cost	Sections of this document
Eddy current — pulsed (PEC)	Monitoring wall thickness at fixed positions and thus may be used to determine corrosion rates Measurements can be performed through coatings, corrosion products and insulation materials Mostly used externally, but can be used in-line (BEM equipment)	Not good for crack detection or for highly localized defects Thickness measurements can be affected by nearby objects (welds, supports, nozzles, etc.) — approx. 5 cm clearance needed Ferromagnetic material only	\$\$	7.3.3.5(a)
Eddy current — meandering wire magnetometer (MWM)	CUI assessment, crack characterization (including SCC), wall thickness measurement and mechanical damage assessment. Flexible scanner can be adapted for a wide range of geometries, pipe diameters and insulation thicknesses	None specifically identified	SS	7.3.3.5(a)
Magnetic flux leakage (MFL)	Can be deployed outside pipe (direct measurement) or inside pipe (flow/pipeline inspection gauge (PIG) conveyed) Can be deployed for tank floor inspections Thickness measurements (indirect wall loss estimation) Surface profile Crack detection Discontinuities	Ferrous material only Thickness of the pipe Dependent upon magnet strength, inspection speed Can be used where pipe is exposed or by digging access pits For USTs, requires tank out of service	\$\$ to \$\$\$	7.3.3.5(b)
Remote field testing (RFT)	Thickness measurements Surface metal loss Discontinuities Equally sensitive to inside surface and outside surface discontinuities; can be applied internally or externally to pipe Can examine thicker materials than ECT; valuable for thick walled ferromagnetic material Internal surface cleaning not required as not sensitive to non-metallic materials/deposits Assessment possible in wet or dry pipe	RFT probes must be moved more slowly than ECT probes; RFT probe must be near the smallest discontinuity required to be detected for at least one cycle in order to detect it Not as accurate as UT for thickness measurements Ferromagnetic material only	Ş	7.3.3.5(c)

Technology name	Uses	Limitations	Cost	Sections of this document
Alternating current field measurement (ACFM)	Crack detection through several mm of non- conductive coating and for cracks up to 25 mm deep Used extensively for weld inspections (pipes or tanks) Portable	Low sensitivity to small discontinuities Signals from nearby geometry changes (such as plate edges) can interfere Signals depend on discontinuity orientation relative to probe	\$\$	7.3.3.5(d)
Impact methods (usage: low to medium)	Identify delaminations within pipe walls and condition of concrete (impact echo can detect delamination from interior or exterior surface; spectral analysis of surface waves can determine elastic properties of each concrete layer)	Does not detect corrosion or indication of and location of broken wires Need to augment data obtained for pipeline asset management with other technologies Pipe needs to be dewatered (internal inspection) or excavated (external inspection)	Internal: \$\$\$ External: \$\$\$ (depending on excavation cost)	7.3.3.5(e)
Remote field transformer coupling (RFTC)	In-line inspection of lined cylinder concrete pressure pipe When used in PCCP pipes, may detect single or multiple prestressing wires	Usually requires dewatering of the pipe Usually requires human entry into pipes	\$\$ to \$\$\$	7.3.3.5(f)
Low frequency electromagnetic technique (LFET)	Flaw detection (ID and OD) in ferrous and non-ferrous materials; able to detect pitting and erosion/corrosion Typically used as a rapid scanning tool with follow-up with UT Not affected by the presence of coating on the surface No great surface preparation is required Accuracy comparable to UT	Pipes up to appoximately 2 cm Ferromagnetic material only Requires skilful and experienced operator	\$\$ to \$\$\$	7.3.3.5(g)
Saturation low frequency eddy current (SLOFEC)	Similar to MFL, but more sensitive/deeper penetrating Can be deployed externally or in-line Can differentiate between front surface and back wall discontinuties Can be applied to tank floors	Ferromagnetic material only Similar to conventional UT For USTs requires tank out of service	\$\$	7.3.3.5(h)
NoPig	Pipeline inspections for metal loss/defects	Ferromagnetic pipeline only	\$\$ to \$\$\$	7.3.3.5(i)

Technology name	Uses	Limitations	Cost	Sections of this document
Radiography — conventional	Thickness (qualitative) Surface metal loss Discriminate internal versus external surface loss (with specific techniques) Crack detection Inspections for blockages, weld discontinuities, deposits, erosion, corrosion or foreign material Useful for all pipe and tank materials (can be used to inspect wide range of materials and thickness) Versatile	Radiation hazardous to workers and public Incapable of detecting laminar discontinuities Some equipment bulky X ray radiography needs electricity Requires two sided access (film side and source side) Results not instantaneous (requires film processing, interpretation and evaluation) Requires personnel trained in radiography and radiation safety	\$\$\$ (equipment plus radiation safety precautions)	7.3.3.6(a)
Radiography — real time (RTR)	Look for discontinuities, welds or damaged areas over relatively large areas of pipe	Similar to conventional radiography testing (RT)	\$\$\$	7.3.3.6(b)
Spark tools	To identify coating holidays following excavation	Test voltage selection is important — can under test or over test	Ś	7.3.3.7
Laser profilometry	Profile surfaces Surface metal loss Discriminate internal versus external surface loss Crack detection Create high resolution, accurate maps of surfaces and corrosion	Pipe must be clear of debris, coatings and moisture Not useful for painted, coated, lined surfaces or with silt or tubercles ID surface inspection only	\$\$	7.3.3.8
Microwave techniques	Inspection of dielectric materials, including non-metallic pipe	Cannot inspect metals and other conductive materials. Limited ability to inspect carbon fibre. Metallic component inspections can be for surface structure/defects only	\$\$	7.3.3.9
Electric continuity tests (usage: medium)	Direct measurement of number of broken prestressing wires Can verify other NDT results and pipe design parameters (if not known)	Cannot be done on pipes with shorting straps or on LCP Excavation required to expose top of pipe and removal of 5 cm wide band along pipe length (note: no dewatering is required)	\$\$ to \$\$\$ (depending on excavation cost)	7.3.3.10(a)
Electromagnetic inspection of concrete pipe (usage: high)	Identify distressed pipes and predict numbers and locations of broken wires. Results can be used directly in failure analysis	Uncertainty high for sporadic wire breaks and close to joints. Less accurate for pipe without shorting straps	\$\$\$ (in service) \$\$\$\$ (dewatered)	7.3.3.10(b)

Technology name	Uses	Limitations	Cost	Sections of this document
Galvanostatic pulse measurement/linear polarization (usage: low)	Detection of areas where corrosion of reinforcement wire in concrete pipe is more likely Can detect corrosion rates directly and is not affected by wet concrete	Application is difficult Needs pipe excavation and possible pressure reduction	\$\$ to \$\$\$ (depending on excavation cost)	7.3.3.10(c)
Remote inspection using PIGs or robotic inspection equipment	Pipe cleaning and inspection (using visual, UT, MFL, EC, RTR and other technologies) Avoids expense and disruption of excavation	Requires launch/retrieval stations Sensitivity/capability dependent on deployed technologies Foreign material exclusion (FME) controls needed on deployed equipment Limited (but improving) ability to navigate bends and vertical runs	\$\$ to \$\$\$ (depending on availability of launch/ retrieval stations)	7.3.3.11
Buried tank inspections	General buried tank inspections	Excavation required for exterior; tank draining required for interior	SS	7.3.6
Weld inspections — visual	Prior to weld to confirm cleanliness, alignment and weld settings After weld to detect undercutting, excess penetration During construction or if leakage at weld site suspected	Requires access to weld surface	S	7.3.7
Weld inspections — liquid penetrant inspection	Checking for surface cracking During construction or if leakage at weld site suspected	See liquid penetrant testing (PT), above	\$	7.3.7
Weld inspections — magnetic particle inspection	Detection of surface and slightly subsurface cracks in ferromagnetic materials During construction or if leakage at weld site suspected	See magnetic particle testing (MT), above Cannot be used with austenitic stainless steels or other non-ferromagnetic material	S	7.3.7
Weld inspections — X ray	Detection of subsurface cracks and inclusions During construction or if leakage at weld site suspected	See Radiography — conventional, above	\$\$	7.3.7
Weld inspections — ultrasonic	Detection of surface and subsurface defects During construction or if leakage at weld site suspected	See UT — conventional, above	S	7.3.7

Resistivity can be used as an initial indicator of the presence of potentially aggressive ions. Resistivity measurements can be made either in the laboratory, using samples collected in the field, or in the field, using either electrodes in contact with the ground surface (Wenner four-point testing) or induction-type electromagnetic conductivity meters, which do not require direct contact with the soil.

Measurements should be performed over the expected range of moisture conditions for the site (i.e. dependencies based on location, summer versus winter conditions or rainy season versus dry season conditions).

Soil analysis determines likely external corrosion rates that can result from the combined presence of a specific pipe to soil potential and certain soil attributes. Resulting corrosivity predictions assume external coating failure and the percentage exposure of bare CS directly to the soil environment. Coating failure may be general or localized.

When soil is analysed, there are certain parameters and information that need to be gathered to understand potential degradation mechanisms on buried piping. Those parameters are:

- General condition;
- Soil type;
- Soil resistivity;
- pH;
- Moisture content;
- Soil chemistry (more complete analysis provides better information);
- Microbial species (numbers and activity);
- Reduction potential.

Chemical analyses of soil and groundwater are generally performed in localized areas identified as containing active corrosion or as being potentially aggressive based on over-the-line surveys. Soil and/or groundwater samples taken near the pipeline are analysed in the laboratory to further quantify environment aggressiveness and to try to identify the cause.

7.3.2.2. Ground penetrating radar

GPR is a method of determining what is underground without digging. GPR can detect underground water, rock, buried ruins and many other types of objects. It is more fully described in Section 8.2.1.1 on locating buried piping.

In principle GPR should be able to detect leaks in buried pipes either by detecting underground voids created by the leak or by detecting anomalies in the depth of the pipe as the radar propagation velocity changes due to soil saturation. Maximum penetration of radar signals is about 2–3 m. At deeper levels radar data are not found to be reliable; however, surrounding soil conditions can have a significant effect on the efficacy of this technique.

Current GPR systems are unlikely to be very useful for detecting leaks; however, they can help to determine locations of buried pipework that are not precisely defined on site plans (see Section 8.2.1.1).

7.3.2.3. Voltage gradient tests

There are a number of voltage gradient tests that can be used on buried piping:

- DCVG, where a current pulse is created along the line, either by interrupting the rectifier or by applying a DC pulse from an outside source;
- ACVG, where a current pulse is created with a low frequency alternating current;
- Pearson surveys [331].

Voltage gradients in soil are measured around the pipeline to locate coating defects. In both cases, voltage drop is measured along the line and plotted on a graph creating a gradient (with a sloping line much like hydraulic gradients) [332].

These NDE techniques can accurately detect and locate holidays and anodes, and indicate whether a defect is a single anomaly or a continuous one. However, the techniques require sufficient ground contact and current flow

on the pipeline to provide sufficient voltage gradient fields at coating holidays. NACE Standard TM0109 [304] provides details on these various techniques.

The primary distinctions between ACVG and DCVG tests are that [331, 333]:

- Signal generators are used to impart pipeline signals for ACVG surveys;
- DCVG uses interrupted CP source or sources. ACVG uses either low frequency AC or interrupted DC (mimicking an AC signal);
- DCVG uses two poles with half-cell type contact probes. ACVG uses two metal probes;
- DCVG probe space varies whereas ACVG probe space is fixed;
- DCVG is subject to interference from existing or stray DC sources whereas ACVG normally is not;
- DCVG normally requires a 400–500 mV shift which cannot be obtained in all conditions. ACVG requires a
 minimum amount of low frequency applied current;
- ACVG requires less operator interpretation because of its fixed spacing, unique applied signal and directional indication;
- DCVG can provide relative cathodic/anodic condition of CP at a moment in time;
- DCVG can provide better estimation of size defects.

Both ACVG and DCVG are affected by nuclear power plant ground element connections, especially if pipes are grounded at both ends. Signals required for detectable voltage gradients at coating flaws increase as amounts of grounding connected to piping increase [334].

(a) Direct current voltage gradient

DCVG survey technique can be used to detect coating defects in buried steel pipework. This technique involves application of a pulsating DC current to pipework and detection of a voltage gradient due to a coating break.

When direct current is applied to a pipeline a voltage gradient is created in the soil due to passage of current from the anode bed through the resistive soil to bare steel exposed at coating faults. The voltage gradient surrounding each coating fault becomes larger and more concentrated with greater current flowing and more closeness to a coating fault location.

To ease interpretation and to separate the DC whose gradient is being monitored from other DC sources, an interrupter is inserted into the negative lead of the power source to pulse the supply. The potential difference between two half cells which have been placed in the soil is measured by means of a special millivoltmeter.

In surveying a pipeline (see Figs 89, 90 and 91), the surveyor walks the pipeline route testing for the pulsing voltage gradient at regular intervals by placing the electrodes one in front of the other at a spacing of 1–2 m and parallel to the pipeline direction. As a coating fault is approached, the surveyor will observe the millivoltmeter needle begin to respond to the pulse, pointing in the direction of current flow, which is towards the coating fault location. The amplitude of the pulsing meter needle increases as the fault gradient epicentre is approached and then changes direction completely, reversing and slowly decreasing in amplitude as the surveyor moves away from the fault epicentre location. By retracing to where the meter changes direction, a point can be found where the meter needle shows no deflection in either direction (a null). The coating fault gradient epicentre is then sited midway between the two electrodes. This position is then marked in the soil. The above procedure is then repeated at right angles to the first set of observations that were made parallel to the pipeline direction, to locate a second midpoint. Where the two midpoints cross in the soil above the pipeline is the gradient epicentre.

Advantages and limitations of the technique are:

- It is useful in identifying sites of potential coating breaks; however, identified sites may not be associated with actual leakage;
- DCVG is particularly suited to complex CP systems in areas with a relatively high density of buried structures. These are generally the most difficult survey conditions. DCVG equipment is relatively simple and involves no trailing wires;



FIG. 89. Direct current voltage gradient methodology (schematic) [60].



FIG. 90. Direct current voltage gradient technique (courtesy of Pipeline Performance Technologies, South Africa).

- Although a severity level can be identified for coating defects, rating systems are empirical and do not provide quantitative kinetic corrosion information. Survey team's rate of progress is dependent on the number of coating defects present;
- Terrain restrictions are similar to the CIPS technique (Section 7.3.2.3(d)).

(b) Alternating current voltage gradient

ACVG (Fig. 92) is similar to DCVG in that it is used to detect coating defects on buried pipelines. However, this technique employs an AC signal injected onto the pipeline and the potential gradient along it is compared between two mobile earth contacts. Where there are coating defects increases in voltage gradient occur.



FIG. 91. Direct current voltage gradient test equipment (courtesy of Electronic Pipeline Technology Ltd).



FIG. 92. Example of an alternating current voltage gradient device [331].

A traditional pipe locator is used to detect an AC current (typically 4 Hz) applied to the pipeline. Signal losses are correlated to fault size.

(c) Pearson survey

The Pearson survey is similar to the DCVG technique in that it is used to detect coating defects on buried pipelines. The technique, however, employs an AC signal injected onto the pipeline and potential gradient along the pipeline is compared between two mobile earth contacts. Increases in voltage gradient occur at coating defects. This technique has the same limitations as the DCVG and ACVG techniques but ACVG tends to give better results than a Pearson survey [331]. Figures 93, 94 and 95 show examples of equipment used and the methodology.

(d) Close interval potential survey

CIPS is used to assess CP system effectiveness over a pipeline's length.

Cathodically protected pipes are equipped with test stations where electronic leads are attached to measure pipe-to-soil potential. This potential should be sufficiently cathodic to ensure adequate corrosion protection but not excessively cathodic to produce coating damage and/or hydrogen embrittlement. Potentials at test stations only originate from a small fraction of the total pipeline length (about twice the depth of pipeline burial). A CIPS measures potentials along the entire length to gain a better appreciation of CP system performance.

In a CIPS the technician is electrically connected to the pipeline by means of a trailing wire. This wire unwinds from a spool as the technician walks the length of the pipeline. Pipeline potential is then measured with a set of reference electrodes at ground level, positioned directly over the pipe, at intervals of about 1-2 m.

In practice, a three-person crew is required to perform these measurements. One person walking ahead locates the pipeline with a pipe locator to ensure that the potential measurements are performed directly overhead the pipeline. This person also carries a tape measure and inserts a distance marker (a small flag) at regular intervals over the pipeline. The markers serve as distance calibration points. The second person carries a pair of electrodes connected to the test post by means of a trailing thin copper wire and the potential measuring instrumentation. This person is also responsible for entering specific features as a function of the measuring distance.



FIG. 93. Pearson coating test holiday detector (courtesy of Electronic Pipeline Technology Ltd).



FIG. 94. Example Pearson survey [331].



FIG. 95. Pearson survey methodology (schematic).

Physical details (road, creek, permanent distance marker, fence, rectifier, block valve, etc.) serve as useful geographical reference points when corrective actions based on survey results have to be taken. The third person collects the trailing wire after individual survey sections have been completed.

In order to obtain an indication of the 'true' pipe-to-soil potential, voltage drop error in the potential readings associated with CP current flow through the soil has to be minimized. This is achieved by interrupting CP current flow for an instant. Typically, current output from several influencing rectifiers (and also foreign sources of current) needs to be interrupted synchronously. Increasingly, global positioning system (GPS) timing devices are used for

synchronous switching devices. Figure 96 shows a typical test arrangement and Fig. 97 shows typical test data obtained. NACE provides a guide, Standard SP0207 [302], to performing CIPS.

Advantages and limitations of CIPS are [60] that it provides a complete pipe-to-soil potential profile, indicating the status of CP levels. Interpretation of results, including identification of defects, is relatively straightforward. The rate of progress of the survey team is independent of coating quality on the pipeline. When the entire pipeline is walked, condition of the right-of-way and CP equipment can be assessed together with the potential measurements.

Fundamentally, these surveys do not indicate the actual severity of corrosion damage, because corrosion potential is not a kinetic parameter. The entire pipeline length has to be walked by a survey team and significant logistical support is required.

(e) Pipe-to-soil potential survey

When a pipe is buried, moisture in the soil forms an electrolyte. Anode and cathode areas are both on the same pipe structure and the pipe provides the return circuit. The lower the resistance, or more conductive the electrolyte, the greater will be the flow of electrons and the higher the rate of corrosion. Thus corrosion rates in salt polluted soils and in clay gumbo soils will be much greater than if the same pipe were backfilled with high resistance sand or gravel. If sand or gravel backfill remains dry, then the electrolyte is eliminated and the corrosion process will not continue. It is therefore evident that corrosion rates can be influenced by soil composition.

The physical condition of the soil environment can create different types of corrosion cells. These are sometimes called 'concentration cells'. One example is when a pipe is installed along the bottom of the excavated trench on dense and undisturbed soil, while the rest of the pipe wall is in contact with the mixed, loose and aerated soil of the selected backfill. These interfaces are commonly referred to as 'hot spots'.



FIG. 96. Close interval potential survey testing.



FIG. 97. Sample close interval potential survey results [60].

The pipe-to-soil potential test is one of the standard measurement techniques in the evaluation of corrosion and the degree of CP applied to buried metallic structures. It can also be used to detect areas of concrete pipe where wire corrosion from the external surface is most likely.

A copper sulphate half-cell reference electrode is most commonly used to contact the soil. Normally, natural static potentials of unprotected buried steel will vary from -0.30 to -0.80 V, with reference to the copper sulphate electrode. Such differences in pipe-to-soil potentials along a pipeline indicate voltage drops in the soil between test points. This means that galvanic currents will flow through the soil between the anodic and cathodic points, the magnitude of current flow depending on soil (electrolyte) resistivity and the voltage drop in the galvanic cells. If static pipe-to-soil potentials along a pipeline were of equal values, galvanic currents could not flow and there would be no corrosion.

To make a pipe-to-soil test observation, a lead wire attached to a copper sulphate electrode is attached to the positive (+) post of a voltmeter. The wire attached to the negative (-) post of the meter is attached to the pipe at any convenient point. Contact can be made directly by clipping to an above ground valve, fitting, riser or even by attaching to a probe bar pushed into the ground to contact the pipe. The plug end of the copper sulphate electrode is then placed firmly against the moist soil at a position relative to the top of the buried pipe. If the soil is dry, it will be necessary to wet the ground in order to ensure good contact between the soil and the electrode. Test set-up is shown in Figs 98 and 99.

The voltmeter reading indicates pipe-to-soil potential at a particular point on the pipeline. By using the same contact point on the pipe, but using a long wire between the meter and the copper sulphate electrode, it is possible take a series of pipe-to-soil test measurements at a number of points along the pipeline and to identify any 'hot spots'.

This particular technique is useful in identifying potential corrosion hot spots; however, these hot spots may not be associated with a leakage point.

(f) Cell-to-cell potential survey

A cell-to-cell potential survey can be used for pipelines that are not electrically continuous. It is similar to the pipe-to-soil survey. The test measures differences in potential between locations on the soil surface. Potentials are measured at fixed intervals directly above the pipe's centreline (with reference to a stationary electrode) and at fixed distance from the centreline to determine if current flows towards or away from the pipe. Higher negative potential at the centreline compared to points away from the centre is an indication of likely local corrosion. The



FIG. 98. Pipe-to-soil test set-up [335].



FIG. 99. Soil potential measurement [336].

system for cell-to-cell potential measurements consists of a stationary reference electrode, two moving electrodes, a high impedance voltage meter and a method for measuring distances along the pipeline.

(g) Area potential and earth current survey

An APEC survey uses a computer based data logger to collect $Cu/CuSO_4$ reference cell potentials over an area, while dual earth current voltage gradients are collected in an X–Y grid. After processing, the data are integrated for evaluation into a geographic information system (GIS) in relation to the locations of all buried plant assets.

These methods yield corrosion activity over an area, as well as a relative severity ranking based upon both current flows through the soil and potentials. These can be used to prioritize direct inspection locations and to

understand where the threat of corrosion is low to support a decision to not investigate at a location. Practitioners from the USA, Canada and Germany have published and patented these approaches.

APEC surveys are performed around a site over the piping of interest using a grid approach; $6 \text{ m} \times 6 \text{ m}$ spacing is common. For sites without active CP systems, only a native survey (free corrosion potential) is performed. For sites with active CP systems, a second interrupted survey is used to evaluate the effectiveness of the CP system at supplementing the corrosion control in areas where coating degradation may exist, but adequate protection is achieved. It should be noted that the degradation of coatings is not an adverse condition requiring immediate corrective actions as long as the CP systems are providing the supplemental protection necessary to control corrosion. The combination of coatings and CP can be highly effective at managing external corrosion of buried piping and extending the asset service life. A schematic demonstrating how coating condition and CP effectiveness are evaluated is shown in Fig. 100.

Another subtle benefit associated with APEC surveys is the classification or grouping of similar response areas. In the event that a significant external corrosion condition is discovered during an excavation and direct examination, the APEC information can be consulted to identify other locations at the site with similar current flow and CP voltage levels. Soil characteristics should also be considered as a complementary information source.

7.3.2.4. Alternating current current attenuation survey

The ACCA technique can be used to detect coating defects in buried steel piping. It does not require ground contact. It is applicable for pipelines under magnetically transparent cover, such as earth, ice, water or concrete. An AC current applied to the pipeline creates an electromagnetic field around it, which is measured by a magnetometer. Current gradually decays with distance unless there is a coating defect, in which case there is a sudden drop in current (Fig. 101).

ACCA may be hindered by interference with AC power lines and it may not detect small pinholes in the coating.

(a) C-scan

C-scan is a form of ACCA survey. It uses inductive coupling between a pipeline and antenna to measure signal current strength remaining on the line at each survey point. From this, the signal loss rate (logarithmic attenuation) from any previously stored survey point can be determined to give an indication of the average coating condition on the section between those points. Attenuation values are independent of the applied signal and are



FIG. 100. Sample area potential and earth current survey interpretation results (courtesy of Structural Integrity Associates Inc.) [337].

an index of coating condition. C-scan can provide a clear indication as to whether faults are present in the section without surveying the entire pipeline [331].

(b) Pipeline current mapper PCM

The PCM tool can be used to locate pipe, identify areas of current loss and determine depth of cover [334]. It is another type of ACCA instrument for which an extremely low (near DC) frequency (4 Hz) is used to mirror as closely as possible the DC current generated by CP systems. Integral data logging functions store current data so that current loss versus distance can be plotted [331].

The system shown in Fig. 102 consists of a portable transmitter and hand held locator. A transmitter applies a special signal to the pipeline and the locator (shown) locates this unique signal at distances of up to 30 km, identifying pipe position and depth. Once the pipe has been located the technician can map leakage currents along the pipe, allowing coating defects to be quickly identified. Once the segment of pipe where the defect lies has been identified, by using an A-frame, defect position and depth can be further pinpointed to within 1 m.



FIG. 101. Example of buried pipeline current attenuation behaviour with (left) external coating in excellent condition and (right) coating with deterioration on one section [331].



FIG. 102. Pipeline current mapper (alternating current current attenuation) detector (courtesy of and copyright 2014 Radiodetection Ltd. All rights reserved.).

Congested nuclear power plant buried pipeline that is connected to grounding elements may be difficult to locate using the PCM tool, as loss of test signal can adversely affect results [334].

7.3.2.5. Magnetic tomography method

When a ferromagnetic material is stressed, associated dimensional changes manifest themselves as changes in magnetic susceptibility. This change is known as the inverse magnetostrictive effect, or Villari effect. By mapping piping magnetic susceptibility using a non-contact scanning magnetometer it is possible to detect local changes in magnetic susceptibility. Local changes may be due to local discontinuities in pipework geometry due to corrosion attack, erosion, dents, cracks, or delaminations, or to increased loads and mechanical stress concentrators (e.g. sagging, deflections, loss of stability in areas of landslips and seismic active zones).

MTM uses highly sensitive magnetometers to passively detect magnetic anomalies within a pipeline typically associated with pipeline flaws; consequently, the presence of high voltage transmission lines above the pipeline may interfere with the survey if installed parallel with the pipeline.

A number of companies manufacture magnetic tomography equipment, with each type having its own published limitations. Typical limitations provided by one manufacturer are as follows:

- Pipe size: 56 mm and greater;Pipe wall thickness: 2.8–44 mm;
- Distance between magnetometer and pipeline: Max. of $15 \times pipe$ diameter;
- Cannot detect defects which do not change the stress field within material (i.e. blow holes, pitting).

For this technique to work it is important that a series of readings are taken when the operator is confident that the system is free from significant degradation. At this point the location of pipe discontinuities, such as welds and joints, that might impact on future measurements would be identified. Once such a baseline magnetic signature of the system is obtained, it should be possible to monitor the line in the future for signs of significant deterioration. Figures 103 and 104 illustrate the process.

Magnetic tomography charts pipe section attributes and characteristics by registering and analysing changes in the magnetic field of the pipeline. These changes are related to stress, which in turn is related to defects in metal and insulation. Magnetic measurement data are collected from the ground surface and anomalies detected are a function of stress, mechanical loading and structural changes in the metal.



FIG. 103. Magnetic tomography method data acquisition for a pipeline (courtesy of Transkor Group Inc.).



FIG. 104. Magnetic field in the absence of (left) and presence of (middle) metal defects, and processed measurements showing pipe flaws (right) (courtesy of Transkor Group Inc.) [338].

Magnetic tomography does not measure the geometric dimensions of defects alone but instead measures stress caused by the defect areas (clusters) and identifies their character, location and orientation in accordance with the location and orientation of the stress areas. Linear and angular coordinates of anomalies in the metal and coating are defined within a tolerance of $\pm/-0.25$ m.

7.3.2.6. Leak testing

Leak testing is NDT that concerns escape or entry of liquids or gases from pressurized or into evacuated components or systems intended to hold these liquids. Leaking fluids (liquid or gas) can penetrate from inside a component or assembly to the outside, or vice versa, as a result of a pressure differential between regions or due to permeation through a somewhat extended barrier. Leak testing encompasses procedures for locating (detecting and pinpointing) leaks, determining leakage rates and monitoring for leakage [339]. As a major expense of any buried piping repair is the cost of excavation, most leak detection methods employed for buried piping are designed to be indirect. If direct access to a pipe is available (e.g. excavation already done or pipes in an accessible underground duct) then simple visual inspections or bubble testing (for gases) are often sufficient. For ease of reference both indirect and direct methods are included in this section. A detailed overview of leak testing is given in IAEA Training Course Series No. 52 [340].

In the context of buried piping, leak detection typically consists of visual walking of the pipeline, methods to detect the sound of leaking fluid (acoustic methods), hydraulic methods (e.g. mass balance, segment isolation, hydrostatic tests), methods that inject a substance into the fluid stream and then attempt to detect substance leakage (e.g. tracer gases, radiotracers or dyes) and remote sensing methods (thermography, GPR). Groundwater monitoring programmes can in some cases assist and in some cases permanent instrumentation can be deployed to detect leaks more rapidly as they occur. Each of these is described below.

- (a) Visual methods
 - (i) Walking the line

Walking the line, although more strictly a form of surveillance (Section 7.4.1), is referred to in some contexts as an inspection method. Pipe leaks typically find a path to ground level, but the exact leakage location may not be where it surfaces. Turbulent sounds associated with leakage may also be detected by trained observers. Walking the pipeline at ground level during daytime for visual signs of leakage, or at night for leakage noise, has proven useful. Visual signs of leakage may include a change in the surface contour of the ground, sinkholes, soil discolouration, softening of paving asphalt, pool formation, bubbling water puddles, a noticeable odour or sounds of turbulence. See Fig. 105 for an example.

Observation of conditions in building basements or vaults where buried piping enters is also useful. Observers should look for evidence of leakage, any peeling or bubbling of coatings, rust staining or cracking. Any leaking fluids should be sampled and analysed to help determine their origin.

Due to its limitations the process is not useful for pipes under buildings, roads, concrete pads or naturally wet areas.

Where piping is accessible (e.g. already excavated or for underground pipe located within a tunnel) visual inspection will often readily locate a leak location. Direct visual inspection is covered in more detail in Section 7.3.3.1.

(ii) Bubble testing

Bubble testing involves placing a test liquid in contact with the lower pressure side of a suspected leaking pressure boundary, typically at a component such as a fitting. Gas leakage is detected by observing bubbles formed in the liquid or liquid film at leakage exit points (Fig. 106).

Although this inspection technique is not suitable for (covered) buried pipes, it may be used for underground pipes, such as those located within a tunnel.

This method provides an immediate indication of the existence and location of large leaks (1 Pa L/s to 10^{-2} Pa L/s). Longer inspection times may be needed for detection of small leaks (10^{-2} Pa L/s to 10^{-3} Pa L/s).



FIG. 105. (Left) Ground level leak indication; (right) actual leak once excavated (courtesy of Ontario Power Generation Inc.).



FIG. 106. Foam film to detect gas bubbles (courtesy of Julia Lowther, Shoebox Studio) [341].

(iii) Vacuum boxes

Vacuum boxes (Fig. 107) can be used on tanks in conjunction with bubble test solutions. They are used to check for leaks or faults in the welding of bottom and annular plates of tanks, or in geomembrane liner seams. The boxes are typically constructed as steel containers with an acrylic sheet on top, having an inlet valve connecting to a vacuum pump. The attached vacuum pump creates a vacuum in the box, which shows bubbles on soapy water applied on the joint for any leaks or weld defects. The boxes can be adapted to fit in a variety of configurations, including flat bottomed devices and devices specially designed to test inside corners, curves or where two sides meet at a floor.

(b) Acoustic methods

(i) Acoustic leak searches

Turbulent flow of a pressurized gas through a leak (Fig. 108) produces sound in both sonic and ultrasonic frequencies. Large leaks can sometimes be detected with the ear.

Water leaks in underground, pressurized pipes may make many different sounds:

- 'Hiss' or 'whoosh' from pipe vibration and orifice pressure reduction;
- 'Splashing' or 'babbling brook' sounds from water flowing around the pipe;
- Rapid 'beating/thumping' sounds from water spray striking the wall of the soil cavity;
- Small 'clinking' sounds of stones and pebbles bouncing off the pipe.



FIG. 107. Vacuum box testing (courtesy of Inspections, X-Ray & Testing Pty Ltd; used by permission).



FIG. 108. Turbulence caused by fluid flow through an orifice.

The 'hiss' or 'whoosh' sound, which often sounds like constant static noise, is the only one which is always present for leaks in pipes with 207 kPa (30 psi) or higher water pressure. The other sounds may or may not be present and usually they are not as loud. Typically, then, the 'hiss' or 'whoosh' sound is the one targeted for leak detection [342]. Metal pipes, particularly iron mains between 15 cm and 30 cm, copper services and steel pipes transmit water leak sounds for great distances (greater than 30 m) in every direction. Asbestos cement pipe and PVC pipe do not transmit the sounds nearly as far. Soil absorbs water leak sounds very quickly (high frequencies to a greater degree than low frequencies). Hard street surfaces and concrete slabs resonate with the sounds of the leak and leaks may be heard for 2–3 m or more on either side of the pipe.

Smaller leaks can be found with ultrasonic probes operating in the range of 35–40 kHz, although actual emissions from leaks range to over 100 kHz. The process involves listening at hydrants, valves and meters first (since sound travels on the pipe walls better than through the soil). Once the loudest and second loudest locations are located, the operator follows the pipe route between them and looks for a peak in sound levels that indicates a leak location (see Fig. 109).

Acoustic probes can also be deployed more directly inside of pipelines in either a free swimming or tethered manner. Since they travel closer to the leak source they can detect smaller sized leaks. Section 7.3.3.11 provides more detail on such applications.

A leak noise correlator is an electronic locator to find leaks in pressurized water or gas lines. Such a device uses sound sensors that are placed in contact with a pipe at two or more points. Sound data are processed through a mathematical algorithm which compares or correlates the recordings to determine the difference in time it takes noise to travel from the site of the leak to each sensor. If the distance between the sensors is known in advance, the timing information can be used to determine the location of the leak.

(ii) Acoustic emission monitoring

Acoustic emission monitoring (AEM) technology can be employed to look for defects or leakage in real time without shutting down the equipment in question. AEM may be defined as a transient elastic wave generated by the rapid release of energy within a material. With AEM equipment one can 'listen' to the higher frequency sounds of cracks growing, fibres breaking and many other modes of active damage in the stressed material. AEM technology can be applied to storage tank floors, pressure vessels and pipelines. EPRI has done recent work on utilizing AEM techniques for buried piping leak detection and characterization [343].

Figure 110 shows an application of the technology to inspect a gas pipeline in Ukraine, in which boreholes 50–80 m apart allowed for inspection coverage of the entire pipeline. To install sensors the pipe normally needs to be excavated and coatings removed so that the sensor can contact bare metal. Alternatives are also available that can be driven into the ground until the pipe is contacted.

AEM technology is also available for structural health monitoring of in-service tanks, but above ground tank applications are most common (see Section 7.4.5.1).



FIG. 109. Water leak pinpointing (courtesy of SubSurface Leak Detection, Inc.) [342].

(iii) Remote acoustic leak detection

Tethered and non-tethered (free swimming) in-line acoustic leak detection systems have been developed for buried water pipeline inspection. Such systems (Fig. 111) introduce a sensor on a cable or free flowing ball into the water distribution system and allow for recording of pipe data. Such systems can be used to detect leaks, gas pockets and structural defects, and can assist in pipeline mapping.

(c) Hydraulic methods

Leaks change pipeline hydraulics and so change steady state pressures or flow readings. Local monitoring of pressure or flow changes at only one point can therefore provide simple leak detection.

Where piping systems have flow instruments or meters installed, simple flow mass balance techniques can be used to locate leakage or loss points. In the steady state, the mass flow entering a leak free pipeline will balance the mass flow leaving it; any drop in mass leaving the pipeline indicates a leak. Segments of piping systems can sometimes be isolated to assess their impact on mass flows. Increases in make-up flows or pump outs of tanks can be indicative of leakage.

Real time transient models (RTTMs) are enhancements of balancing methods as they additionally use the conservation principle of momentum and energy. They are currently used in petrochemical pipeline applications. They make it possible to calculate mass flow, pressure, density and temperature for steady state and transient conditions at every point along a pipeline in real time with the help of mathematical algorithms. Using RTTM technology, leaks can be detected during steady state and transient conditions.



FIG. 110. Acoustic emission monitoring bore-hole and instrumentation set-up for gas pipeline inspection in Ukraine [344].



FIG. 111. Sahara leak and gas pocket detection system (courtesy of Pure Technologies).

Leaks may also be detected by a hydrostatic test. The buried piping system may be pressurized to a certain hydrostatic test pressure and pressure maintained for a period of time to detect potential leaks in the form of a line pressure drop. Optionally, test pressure may also be correlated to a maximum flaw size (length and depth) that would not fail during the test.

(d) Tracers and dyes

Numerous leak detection methods are available that inject special substances into a system and detect their leakage outside of the system's boundary. These include a variety of tracer gases, chemicals, radiotracers and dyes. Helium is commonly used in buried pipe system testing.

(i) Tracer gases

Tracer gases are often used in industrial leak detection. In most cases, gases with high diffusion rates and small molecular size (e.g. H_2 , He) are desirable; however, a persistent gas or a gas with a low diffusion rate may be recommended in some circumstances (e.g. when probing container surfaces). A persistent gas will remain in the leak area longer and may facilitate leak detection and location because of an increase in tracer gas concentration. Tracers need to be non-reactive with system components and not cause an environmental hazard if released. Detectors need to be compatible with the anticipated leak size, as some detectors may not be sensitive to too small or large concentrations of the substance being detected.

(ii) Helium leak testing

Helium leak testing involves pressurizing a drained section of pipework or tank suspected of having a leak with a mixture of compressed air and helium (a typical mixture might be 10–20% helium and 80–90% nitrogen). Pressurization takes place to a percentage of normal operating pressure.

Helium will escape through small component wall imperfections or at mechanical joints and saturate the ground. The helium will quickly rise to the surface even from components buried several metres underground, assuming some soil–air permeability (Fig. 112).

Using a field portable mass spectrometer helium leak detector the area above the pipeline is scanned for the presence of helium. Since helium is only present in the atmosphere at about five parts per million even the smallest leaks should be detected. The main disadvantage of this technique is that it can only be carried out when the affected pipe is out of service.



FIG. 112. Sample fire line pipe leak detected by helium leak detection equipment (courtesy of MediVac Technologies) [345].

(iii) Chemical tracers

Systems are also available that can perform similar testing using chemical tracers with equipment remaining in service. Such systems can be used, for example, to detect leaks from USTs. In such an arrangement a network of sampling ports would be installed near tanks, piping or other objects to be tested. A volatile chemical tracer is added to the system, and samples from the ports are analysed in a mobile laboratory. Positive results indicate the presence and approximate locations of any leaks in the system.

(iv) Radiotracers

Leak detection using radiotracer techniques is a widespread application of radiotracers in industry. Radiotracer techniques are sensitive, effective and competitive for on-line leak detection, especially in heat exchangers and underground pipelines. They allow early detection of small leakage before it can develop into major pollution incidents. The methods used for on-line leak detection in heat exchangers and underground pipelines can achieve detection limits of up to 0.1% of stream flow [346].

Similar to helium leak testing (Section 7.3.2.6(d)), an appropriate radiotracer is injected into a pipeline and a certain pressure is applied to allow the radiotracer to leak out (if any). The leaked tracer may migrate towards the ground surface in the case of a gaseous radiotracer or be adsorbed on the soil or thermal insulation around the leak point in the case of a liquid radiotracer. Leak locations are discovered by surveying radioactivity from the leaked radiotracer.

For shallow depth pipes detection of leaked radiotracers is performed from the ground surface (radiotracer gamma radiation or the gaseous radiotracer itself can penetrate to the surface). For deeply buried pipelines detection is performed from inside of the pipeline using pipeline inspection gauges (PIGs) equipped with one or more radiation detectors.

Three methods are used generally to detect and locate leaks in buried pipelines: the tracer patch migration method, velocity drop method and radiotracer–detector PIG method. A full description of these methods and typical equipment required is included in IAEA Training Course Series No. 38 [346].

(v) Dyes

In dye testing a coloured or fluorescent dye is added to a system and leaks searched for along its length (UV lamps would be used for fluorescent dyes). Pipelines and tanks can remain in service during such testing. Permeable soil conditions are needed for successful use and appropriate environmental approvals must be obtained.

(e) Remote sensing

(i) Infrared thermographic testing

Infrared (IR) thermographic testing can detect and locate subsurface pipeline leaks, voids caused by erosion, deteriorated pipeline insulation and poor backfill. When a pipeline leak has allowed a fluid, such as water, to form a plume near a pipeline, the fluid's thermal conductance is different from dry soil or backfill. This is reflected in different surface temperature patterns above the leak. A high resolution infrared radiometer scan can display areas of differing temperatures (see Fig. 113). This system measures surface energy patterns only, but the patterns that are measured on the ground above a buried pipeline can help show where pipeline leaks and resulting erosion voids are forming. Problems can be detected as deep as 30 m below the ground [348].

Long lengths of pipeline can be surveyed using methods allowing for high elevation surveys such as helicopters.

For tanks, IR testing can be used to locate hotspots and missing insulation on surfaces that are visually accessible.

ANST's NDT Handbook Volume 3 [349] describes several applications of IR to detection of chemical leakage from pipelines and storage vessels and for inspection of aboveground storage tanks for erosion, corrosion or insulation damage.



FIG. 113. Aerial thermogram of buried cross-country oil pipeline revealing subsurface contamination caused by a leak [347].

(ii) Ground penetrating radar

GPR is a method of determining what is underground without digging. GPR can detect underground water, rock, buried ruins and many other types of objects. It is more fully described in Section 8.2.1.1 on locating buried piping.

In principle, GPR should be able to detect leaks in buried pipes by detecting either underground voids created by the leak or anomalies in the depth of the pipe as the radar propagation velocity changes due to soil saturation. Maximum penetration of radar signals is about 2–3 m. At deeper levels radar data are not found to be reliable. Surrounding soil conditions, however, can have a significant effect on the efficacy of this technique.

(f) Groundwater monitoring

In some cases groundwater monitoring wells can be used to assist in leak searches for radioactive materials or other contaminants. These are more fully discussed in Section 7.4.5.5.

(g) Preinstalled leak detection systems

A number of technologies are available that when preinstalled along piping runs can provide leak detection capability. These include fibre optic cables (which respond to temperature changes and the side of pipes resulting from leaks), impedance differential cables (buried near buried piping, these were developed for hydrocarbons in high consequence areas) and pressure wave monitoring systems (which detect travel time of a pressure wave caused by a leak and can pinpoint its location) [12]. Such leak detection systems are highly sensitive and accurate, but system cost and complexity of installation are usually very high. Applications are therefore limited to special high risk areas, e.g. near rivers or nature preserves.

Tanks containing petroleum and petroleum based substances are typically required to be monitored continually for leakage. Some on-line methods in use for tanks include automatic tank gauging (electronic devices which monitor tank fuel levels to see if the tank is leaking), soil vapour monitoring (leaked petroleum produces vapours that can be detected in the soil gas) and interstitial monitoring (liquid detection in the space between double walled tanks). Where automatic systems are not installed, manual systems involving inventory control, manual tank gauging, groundwater monitoring or tank tightness testing are used.

7.3.3. Direct inspections

Considering access and cost, underground structure engineers should schedule direct inspections at locations that were selected following risk ranking or where indirect inspections have identified a potential degradation site. An informed decision should be made as to whether initial degradation is from the inside or outside surface of the buried pipework. Inspection techniques will be selected on the basis of this judgement.

Direct examinations may require excavation that includes UT, RT or visual inspections and direct soil property measurements. Proper backfilling requirements should also be followed when backfilling the excavated site.

Underground structure engineers should use direct inspection results to update the original risk ranking basis document and adjust any recurring future indirect inspections.

(a) Inside surface inspections

When it is judged that degradation is from the bore of the pipework, it is necessary to open up the pipework to carry out visual examinations (Section 7.3.3.1) and, if practicable, NDT to determine the extent of degradation.

To aid in evaluating the extent of potential degradation and to fully document inspection results for future reference, it is important to obtain samples of water contained in the pipe (for pH and chemical analysis) and any slimes or deposits (for microscopic examination and microbiological culture testing).

Direct visual examination is the preferred method of internal inspection where practicable. Indirect inspection can be undertaken using a number of different tools such as a mirror, fibrescope or borescope. For larger diameter pipework personnel access or a remotely controlled camera should be considered.

Having obtained access to the bore of the pipework a thorough visual inspection of the inner surface of the pipework should be carried out. The inspection should identify signs of:

- General corrosion;
- Pitting corrosion;
- Erosion/corrosion damage;
- Coating damage;
- Fouling or presence of slimes;
- Evidence of coating breakdown elsewhere in the system (e.g. sections of lining).

Having completed an inspection from the inside of the pipework, a decision should be made as to the best course of action, which might involve:

- Formulating a fitness for service case based upon monitoring, visual examination and NDT from inside the pipework surface (see Section 7.6.3);
- Excavating soil surrounding a potential leak site and carrying out visual inspection and NDT of the outside surface of the pipework (Sections 8.2.1.2 and 7.3.3);
- Refurbishing or repairing pipework (see Section 8).

(b) Outside surface inspection

If on reviewing the monitoring results it is determined that the initial failure is from the outside surface of the pipework, it will be necessary to excavate the soil surrounding the pipework to carry out visual examinations (inspections for leaks, corrosion and/or coating damage) and NDT (magnetic particle, ultrasonic inspections, etc.) to determine the extent of the damage.

As an aid to deciding the extent of degradation and to fully documenting inspection results for future reference, it is important that the following data be recorded prior to excavation, during excavation and after excavation:

- Measurement of pipe-to-soil potentials;
- Measurement of soil resistivity;
- Soil sample collection;

— Water sample collection;

- Measurements of under-film liquid pH.

The initial inspection should be limited to one pit. However, if the initial inspection reveals significant deterioration of the coating or pipe, then consideration should be given to increasing the size and number of excavation pits to establish the extent of the deterioration.

Having removed the soil from around the pipe a thorough visual inspection should be carried out of the outer surface of the pipework (see Section 7.3.3.1).

Having completed these inspections from the outside of the pipework, a decision should be made as to the best course of action, which might involve:

- Formulating a fitness for service case based upon monitoring and visual examination and NDT from the outside surface of the pipework (see Section 7.6.3);
- Breaking into the bore of the pipework and carrying out visual inspection and NDT of the pipework bore (Section 7.3.3.1);
- Refurbishing or repairing pipework (see Section 8).

7.3.3.1. Visual testing

(a) General

Visual testing (VT) is the simplest method of pipe examination and can be done on both external and internal pipe surfaces. It is an effective tool for identifying obvious defects in pipeline (e.g. corrosion, pitting or blockages), assessing coating condition, identifying areas for further investigation or confirming the results of other NDT methods.

Visual testing requires adequate illumination of the test surface and good eyesight on the part of the tester. To be most effective it requires personnel training (knowledge of product and process, anticipated service conditions, acceptance criteria, record keeping, etc.).

Internal inspections can be done using personnel crawl-throughs, remote controlled vehicles for large diameter pipe and mirrors, fibrescopes or borescopes for smaller diameter pipes (Fig. 114). Camera systems can usually be attached for permanent recording and complete drainage is not always necessary. Inspections can be combined with direct measurements (e.g. as done via pit gauges or other methods) for detailed assessment of fitness for service.

Visual inspection should look for signs of degradation to outer coatings. Degradation can take the form of cracking, blistering, de-bonding, peeling and general loss of coating material. If the coating or wrapping is deteriorated or damaged, it should be removed so that the condition of the underlying metal can be inspected in detail using standard NDT techniques. Should the initial inspection results confirm significant damage, the excavation size should be extended so that the damage extent can be determined. Any coating damage observed should be repaired in accordance with approved procedures.

If pipework is part of a double containment arrangement, the condition of the secondary containment should be inspected to determine if water and/or soil has entered. The following factors should be verified:

- Both ends of secondary containment extend beyond the ground line;
- Ends of outer pipe are sealed if secondary containment is not self-draining;
- Pressure-carrying pipe is properly coated and wrapped;
- No evidence of leakage into secondary containment.

Internal inspections should attempt to identify signs of:

- General corrosion wastage;
- Leaks, cracks, surface deposits, scaling;
- Pitting corrosion;
- Erosion/corrosion damage;
- Damage to coatings;

— Fouling or presence of slimes;

- Evidence of coating breakdown elsewhere in the system (e.g. sections of lining).

(b) Coating inspections

Inspection priorities for coated pipe will be different from those for bare pipe. For coated pipe, visual inspections of coating conditions will provide insight regarding degradation of the underlying metal. If the coating is in good condition, corrosion of pressure boundary material will be low. If the coating is degraded, further investigation will be required to assess pipe condition and how the damaged coating may impact on other functions (e.g. blockage of piping, valves and heat exchangers). Figure 115 shows an example of a degraded coating.

Visual inspection by a trained and qualified person is the most meaningful method to assess coating condition. Visual inspections should provide information regarding:

- Type of coating applied;
- Recommendations for non-destructive testing (e.g. dry film thickness, low voltage holiday testing);
- Overall coating condition;
- Suggestions for repair, rehabilitation;
- Destructive tests if required to quantify properties (e.g. adhesion test, peel test, soil stress test).

Inspections should identify holidays, cracking, peeling, disbondment, blistering, wrinkling, tape wrap specific defects and mechanical coating damage.

The number of holidays in buried piping and other coated and lined pipe will be a strong function of the quality of the coating operation and the holiday testing inspection. Holidays will expose the underlying pipe surface to the environment. Coating imperfections come from sources such as:

- Holidays generated during coating application (improper surface preparation or environmental conditions during application and curing can be a significant contributor);



FIG. 114. Visual inspection examples: (top left) personnel crawl-through at Callaway nuclear power plant [26]; (top right) remote vehicle inspection (courtesy of EDF and SITES); (bottom left) inspection of coatings at a German nuclear power plant (courtesy of Inspector Systems GmbH); (bottom right) inspection inside partially filled pipe (courtesy of EDF).



FIG. 115. Typical coating failure (courtesy of EPRI) [91].

- Physical damage created during pipe transportation and installation;
- Holidays generated due to coating ageing;
- Service loadings (e.g. cavitation, abrasion);
- Cathodic disbondment from overprotection (buried, cathodically protected pipe only).

7.3.3.2. Liquid penetrant testing

Liquid penetrant testing (PT) is an NDT method utilizing capillary action in which liquid with suitable physical properties penetrates deep into extremely fine cracks or pitting that are opened to the surface without being affected by gravitational forces.

The method consists of depositing on the object surface a special liquid with high surface wetting characteristics. The liquid is drawn into surface defects by capillary action and is allowed time to seep into surface breaking defects. Following removal of excess penetrant a developer is applied that reverses the capillary action and reveals flaws which can be visually inspected and evaluated (Fig. 116).

Liquid penetrant inspection involves the following sequence:

- Pre-cleaning:

- Item surface is cleaned of dirt (by vapour cleaning, degreasing, ultrasonic cleaning, etc.) that may block discontinuity openings.
- Penetrant application:
 - Penetrant (dye or fluorescent penetrant) is applied. Application can be by dipping, spraying or brushing depending on the nature of the item;
 - Penetrant is allowed to remain on the surface for a certain duration (termed the dwell time). During this period the penetrant will seep deeply into any discontinuities.
- Removal of excess penetrant:
 - Excessive penetrant is removed from surfaces to allow for inspection. Removal is done by applying water, proper solvent or emulsifier followed by water (depending on the type of penetrant used). All unwanted penetrant is removed from the surface, leaving only that trapped inside discontinuities.


FIG. 116. Basic liquid penetrant process: apply liquid penetrant; remove excess; apply developer (reproduced from NDT Handbook: Liquid Penetrant Testing. Copyright ASNT, 1999) [350].

- Developer application:
 - Developer (dry powder or wet developer) is applied to item surfaces. This acts as blotting paper and draws penetrant out of discontinuities. Penetrant bleeds to form an indication whose shape depends upon discontinuity type. Indications are recorded by application of special tape or by photography.
- Post-cleaning:
 - Application of penetrant and developer causes surfaces to be contaminated. Item cleaning is important so that no corrosive material remains that may affect serviceability.

The PT method does not depend on ferromagnetism and arrangement of discontinuities is not a factor. It is thus effective for detecting surface flaws in a variety of non-magnetic metal and other materials. It is also used to inspect items made from ferromagnetic steels. Its sensitivity is generally greater than that of magnetic particle inspection (see Section 7.3.3.3).

PT has its own advantages and limitations.

- Advantages:
 - Simple to perform;
 - Inexpensive;
 - Applicable to materials with complex geometry.
- Limitations:
 - Limited to detection of surface breaking discontinuities;
 - Not applicable to porous material;
 - Requires access for pre- and post-cleaning;
 - Irregular surfaces may display non-relevant indications.

7.3.3.3. Magnetic particle testing

Magnetic particle testing (MT) is an NDT method that utilizes the principle of magnetism. It is used to locate surface and slight subsurface discontinuities or defects. MT is only applicable to magnetic materials.

Materials to be inspected are first magnetized through one of many methods of magnetization. A magnetic field is then established within and in the vicinity of the material. Finely milled iron particles coated with a dye pigment are then applied. These particles are attracted to magnetic flux leakage fields and cluster to form an indication directly over the discontinuity, providing a visual indication of the flaw.

Surface breaking and subsurface discontinuities on the material cause the magnetic field to 'leak' and travel through the air. Such a field is called a 'leakage field'. When magnetic powder is sprayed onto such a surface the leakage field will attract the powder, forming a pattern that resembles the shape of the discontinuity. This indication can be visually detected under proper lighting.

Figures 117 and 118 present the principle of magnetic testing.



FIG. 117. Principle of magnetic testing [351].



FIG. 118. Magnetic field lines and magnetic particles influenced by a crack [351].

There are many methods of magnetizing materials. Permanent magnets may be used, however, in many cases electromagnets are considered more effective. Another way of creating magnetic fields is by use of current-carrying coils.

Longitudinal magnetic fields can be established in long items such as bars and cylinders, while circular magnetic fields can be produced by allowing current flow through cylindrical material.

Induction of a magnetic field into the material to be inspected can be achieved by the use of either AC or DC. In general, use of DC produces magnetic fields deeper below the surface and allows subsurface discontinuities to be detected.

Discontinuities can be best detected when magnetic field direction is perpendicular. The chance of detection reduces as the angle between the magnetic field and plane of defect decreases.

When the angle between the magnetic field and the plane of defect is zero, that is, the magnetic field is parallel with the plane of defect, the chance of detection becomes zero.

Application of MT involves the following sequence:

- Pre-cleaning;
- Magnetization;
- Application of magnetic powder;
- Demagnetization.

Advantages and limitations of MT are:

- Advantages:
 - Inexpensive;
 - Equipment is portable;
 - Equipment is easy to operate;
 - Provides instantaneous results;
 - Sensitive to surface and subsurface discontinuities.
- Limitations:
 - Applicable only to ferromagnetic materials;
 - Insensitive to internal defects;
 - Requires magnetization and demagnetization of materials to be inspected;
 - Requires power supply for magnetization;
 - Coating may mask indication;
 - Material may be burned during magnetization.

7.3.3.4. Ultrasonic testing

UT is an NDT method which uses high frequency sound waves (ultrasounds) to measure geometric and physical properties in materials. Frequencies of about 50–100 kHz are commonly used for inspections of non-metallic materials, while frequencies between 0.5 MHz and 10 MHz are commonly used for inspections of metallic materials.

UT can be applied directly to outside pipe surfaces, or can be remotely deployed for inside pipework inspections using inside-flow (PIG) devices or tractor conveyance. See Section 7.3.3.11 for more details regarding inside pipe (in-line) inspections.

Ultrasound travels in different materials at different velocities. Ultrasound waves will continue to travel through material at a given velocity and do not bounce back unless they hit a reflector. Reflectors are any boundary between two different materials or a flaw. Ultrasound generators (transducers) emit waves and in the same position receive reflected sounds (if any). Comparing both signals (emitted and reflected) can determine the position and size of defects. Reflected sound energy is displayed versus time and the inspector can visualize a cross-section of the specimen showing the depth of features that reflect sound (Fig. 119).

Techniques have been developed that employ different wave types, depending on the type of inspection desired:

- Compression waves:
 - Are most widely used.
 - Occur when the beam enters the surface at an angle near 90°. Waves travel through material as a series of alternating compressions and dilations, in which particle vibrations are parallel to the direction of the wave travel.



TR= ultrasonic transducer

FIG. 119. Principle of ultrasonic testing: (a) defect free specimen; (b) specimen with small defect; (c) specimen with large defect [351].

• This wave is easily generated and easily detected and has a high velocity of travel in most materials.

- Longitudinal waves:
 - Are used for detection and location of defects that present a reasonably large frontal area parallel to the surface from which the test is made, such as corrosion loss and delaminations.
 - Are not very effective for crack detection where cracks are perpendicular to the surface.
- Shear or transverse waves:
 - Are generated when the beam enters the surface at a moderate angle. Shear wave motion is similar to the vibrations of a rope that is being shaken rhythmically: particle vibration is perpendicular to direction of propagation.
 - Unlike longitudinal waves, shear waves do not travel far in liquids. Their velocity is about 50% of longitudinal waves in the same material.
 - Have a shorter wavelength than longitudinal waves, which makes them sensitive to small inclusions. This also makes them more easily scattered and reduces penetration.
- Surface waves (Rayleigh waves):
 - Occur when the beam enters material at a shallow angle. They travel with little attenuation in the propagation direction, but their energy decreases rapidly as the wave penetrates below the surface.
 - Are affected by variations in hardness, plated coatings, shot peening and surface cracks and are easily dampened by dirt or grease on the specimen.
- Lamb waves, also known as plate waves and guided waves:
 - Occur when ultrasonic vibrations are introduced at an angle into a relatively thin sheet.
 - Consist of a complex vibration occurring throughout the material, somewhat like the motion of surface waves.
 - Propagation characteristics depend on density, elastic properties and material structure as well as thickness of the test piece and frequency of vibration.

UT is used to detect internal discontinuities. In UT, sounds are generated by transducers made of materials exhibiting piezoelectric effects. Materials exhibiting piezoelectric effects are capable of converting electrical energy into sound energy and vice versa. A typical material is quartz. When a quartz crystal is cut into certain orientations and thicknesses it is capable of generating sounds appropriate for UT inspections. Depending upon the crystal orientation, sounds generated by quartz can be of longitudinal or transverse modes. Figure 120 shows UT in a laboratory.

During an inspection, sound generated by a transducer is transmitted into the material to be inspected. This sound travels in the material with a speed that depends on the type of material. For example, longitudinal waves travel at speeds of 5960 m/s and 6400 m/s in steel and aluminium, respectively. When there is no discontinuity in the material, sound continues to travel until it encounters the back wall of the material.

At the back wall, sound is reflected and continues to travel until it reaches the transducer. There the piezoelectric effect converts sound energy into electrical pulses. Pulses are then amplified and displayed as a back wall signal or back wall echo.

However, if there is a discontinuity in the material, a portion of sound energy is reflected by this discontinuity and another portion continues to travel until it reaches the back wall and is reflected. Under these circumstances, the portion of sound that was reflected by the discontinuity reaches the transducer first and is followed by those reflected by the back wall. In both cases sound energies are converted into electrical signals which then are displayed on the UT flaw detector screen as back wall signals and signals due to discontinuity. By properly calibrating the equipment, both the position of discontinuity with respect to the position of the back wall and the size of discontinuity can be determined.

The fact that UT does not present any hazards to the operator makes this method a good competitor to radiography (Section 7.3.3.6). However, highly skilled and experienced operators are needed to correctly interpret the test results. Unlike with RT, where results are presented in pictorial form, results of UT inspections are only in the form of electrical signals. Knowledge about material, correct transducer movement and proper time base calibration is absolutely necessary to correctly assess test results.

More sophisticated UT equipment is available which allows results to be presented in 2-D or 3-D. This provides greater advantages to the UT method versus RT.

Advantages and limitations of UT are:

- Advantages:

- Requires only one side accessibility;
- Capable of detecting internal defects;



FIG. 120. Ultrasonic testing in laboratory [351].

- Not hazardous;
- Applicable for thickness measurement, detection of discontinuities and determination of material properties;
- Can provide size of discontinuity detected;
- Very sensitive to planar type discontinuities;
- Suitable for automation;
- Equipment is mostly portable and suitable for field inspection;
- Applicable for thick materials;
- Possibility of examination with pipe in service.
- Limitations:
 - Not capable of detecting defects whose plane is parallel to the direction of the sound beam;
 - Requires use of couplant to enhance sound transmission (not for EMAT, GWUT and in-line immersion tools);
 - Requires calibration blocks and reference standards;
 - Requires a highly skilful and experienced operator;
 - Not as reliable for surface and subsurface discontinuities due to interference between initial pulse and signal due to discontinuity.
- (a) Ultrasonic testing thickness measurements

The most fundamental technique used is that of thickness testing. In this case, an ultrasonic pulse is generated by a piezoelectric contact transducer and transmitted into the material through a couplant (Fig. 121). The pulse is a compression or longitudinal wave that is sent in a perpendicular direction into the metal being measured. The signal reflects off the back wall of the product being analysed and the time of flight is used to establish thickness.



FIG. 121. Ultrasonic testing principle for wall thickness measurement (courtesy of NDT Global) [352].

There are instruments that allow testing to be conducted through paint coatings. This is done by looking at the waveform and selecting the area representing the actual material, not the signal developed by the coating.

As the speed of sound in the pipe fluid and wall is known and constant, time of flight will provide quantitative values for the stand-off distance between sensor and internal wall, as well as wall thickness. Changes in stand-off and wall thickness readings will clearly identify internal metal loss; any changes in wall thickness only will identify external metal loss. UT can also detect and size mid-wall features such as laminations and inclusions.

(b) Ultrasonic testing phased array

UT phased arrays present major improvements over conventional multiprobe ultrasonics for inspections. Probe pans are lighter and smaller, permitting less cutback; scans are quicker due to the smaller probe pan; phased arrays are considerably more flexible for changes in pipe dimension or weld profile and for different scan patterns.

Phased arrays use an array of elements, all individually wired, pulsed and time-shifted. These elements are typically pulsed in groups of ~16 elements at a time for pipeline welds. A typical set-up calculates the time delays from operator input, or uses a predefined file calculated for the inspection angle, focal distance, scan pattern, etc. (Fig. 122). Time delay values are back calculated using time of flight from the focal spot and the scan assembled from individual 'focal laws'. Time delay circuits must be accurate to around 2 ns to provide the accuracy required.

From a practical viewpoint, ultrasonic phased arrays are merely a method of generating and receiving ultrasound. Consequently, many details of UT inspection remain unchanged.

Some advantages of phased arrays are:

- Improved capability of detecting and sizing smaller discontinuities such as pitting;
- Allows use of encoders to generate colour coded images of thickness patterns;
- Ability to inspect small diameter pipes;
- Allows for variations in seamless pipe wall thickness.
 - (i) Electronic scans

Multiplexing along an array produces electronic scans (Fig. 123). Typical arrays have up to 128 elements, pulsed in groups of 8 to 16.

Electronic scanning (E-scans) permits rapid coverage with a tight focal spot. If the array is flat and linear, then the scan pattern is a simple B-scan. If the array is curved, then the pattern will be curved. Linear scans are straightforward to program. For example, a phased array can be readily programmed to inspect a weld using both 45° and 60° shear waves, which mimic conventional manual inspections or automated raster scans.



FIG. 122. Schematic showing generation of linear and sectorial scans using phased arrays (courtesy of Olympus NDT) [353].

(ii) Sectorial scans

Sectorial scans (azimuthal or S-scans) use a fixed set of elements, but alter the time delays to sweep the beam through a series of angles (Fig. 124). Again, this is a straightforward scan to program.

Depending primarily on the array frequency and element spacing, sweep angles can vary from $+20^{\circ}$ up to $+80^{\circ}$.

(iii) Combined scans

Phased arrays permit combining electronic scanning, sectorial scanning and precision focusing to give a practical combination of displays. Optimum angles can be selected for welds and other components, while electronic scanning permits fast and functional inspections. For zone discrimination scans of pipeline welds, specific angles are used for given weld geometries, as shown in Fig. 125.

(c) Guided wave ultrasonic testing

GWUT, sometimes referred to as long range ultrasonic testing or LRUT, can be used to examine buried piping provided that access to one pipe end is available. The GWUT principle is similar to conventional UT. A pulse of acoustic energy is launched into the structure using a suitable transducer (or set of transducers), propagates down the structure and the same transducer is used to detect reflections from structure features. The major difference between GWUT and conventional UT is that GWUT requires a boundary. The UT waves are transmitted through the structure with low attenuation, so very large inspection ranges are feasible. Transducers can be piezoelectric or magnetostrictive.



FIG. 123. Schematic illustration of electronic (linear) scanning (courtesy of Olympus NDT) [353].



FIG. 124. Schematic showing sectorial scanning used on turbine rotor (courtesy of Olympus NDT) [353].



FIG. 125. Schematic showing zones on a CRC-Evans weld profile and UT beams from a phased array probe (courtesy of Olympus NDT) [353].

The range over which satisfactory inspection can be achieved will depend on a number of factors. Table 28 contains typical test ranges for above ground pipe, but these values can vary considerably. Factors for buried piping include local environmental conditions (soil conditions, backfill used, temperature, etc.), pipe characteristics (e.g. pipe material, surface roughness, coating used and its condition) and system design (e.g. presence of valves, flanges, reducers, tees, supports, welds or bends). It can be difficult in advance to accurately predict in-service range prior to field testing. The technique's range does allow it to inspect inaccessible areas such as under roadways or slabs or through penetrations where excavation would be difficult or impossible. The larger a pipe's cross-sectional thickness, the less sensitive the guided wave is to a specific defect size. EPRI has produced a detailed application guide [355].

In 2002 EPRI completed a detailed study of GWUT capabilities on bitumen coated and buried piping [356]. It concluded that at the state of development at that time, GWUT was capable of examining up to 9–11 m of bitumen coated and buried pipelines for detection of 10–20% of defects. Increasing soil depth negatively decreases detection capability.

Figure 126 shows a typical inspection collar. Following initial installation such collars can be left installed, with their external leads running to ground level. Such an installation can greatly reduce the cost of subsequent inspections and be used for regular surveillance of critical pipework. Trends can be established using signal processing techniques that compare results over time. EPRI has published a guide to using permanent sensors and related areas for further research [357] and a report on how to obtain credit for using GWUT as a direct examination method [358].

The distance between test positions can be chosen such that it is the same or even shorter than the diagnostic range with a realistically achievable number of test locations (Fig. 127). Importantly, complete pipe coverage can be achieved with only a small number of tests and so inspection efforts are kept to a minimum.

TABLE 28.	GWUT	TYPICAL	ABOVE	GROUND	TEST
RANGES IN	N EACH	DIRECTIC	ON FOR I	DIFFERENT	PIPE
CONFIGUR	ATIONS	(ADAPTEI	D FROM	REF. [354])	

Pipe test condition	Typical range		
Clean, straight pipe	50–200 m		
Clean, wool insulated pipe	40–175 m		
Insignificant or minor corrosion	20–50 m		
Significant corrosion	15–30 m		
Spun epoxy coating	30–50 m		
Well packed earth	15–30 m		
Thin hard bitumen tape coated	5–25 m		
Thick soft bitumen tape coated	2–8 m		
Grout lined pipe	10–30 m		

Figure 128 shows an example of GWUT test results. Results can be displayed in an A-scan type representation, which shows received amplitudes of T(0,1) and one flexural mode, called F(1,2), as a function of distance from the transducer ring in both directions and additionally in a C-scan type representation, which shows received amplitudes as a function of distance and angular position around the circumference. Cross-sectional changes appear as reflected signals as demonstrated in the A-scan and C-scan traces.



FIG. 126. Guided wave testing, https://commons.wikimedia.org/wiki/File:Guided_wave_testing_GWT.jpg#



FIG. 127. (a) Different test positions at distance L from each other on pipe, and (b) schematic of unit grid cell for guided wave ultrasonic testing (courtesy of Guided Ultrasonics Ltd) [359].



FIG. 128. Typical guided wave ultrasonic testing test result from a 6 in pipe with 50 mm diameter defect with depth of half wall thickness. Defect is clearly visible at 17 dB above the coherent noise (courtesy of Guided Ultrasonics Ltd) [359].

In the dead zone (green area) and near field (grey area) around the transducer ring at 0 m, interpretation of data is not possible.

(d) Electromagnetic acoustic transducer testing

EMAT (Fig. 129) is another form of UT inspection. Unlike conventional UT transducers, EMAT creates UT energy by inducing an AC within a magnetic field. It can be incorporated into a scanner for the purpose of pipe screening. EMAT can be used on any piping that is physically accessible and can look through coatings and linings.

EMAT transducers have two probes: a pulser and a receiver. The pulser sends a UT signal in both directions around the pipe circumference and the receiver receives the signals from both directions. Changes in sound path and time of flight of the UT signal represent changes in the material such as wall loss. A major benefit of EMAT is that it does not require total access to gain the inspection data needed. Only 1/3 of the line circumference is needed to send full volumetric sound through the pipe circumference and provide accurate results. Its main disadvantage is that the transducers typically are larger than the piezoelectric transducers used in other UT applications.

Conventional UT inspections with piezoelectric transducers require a couplant or liquid medium. This is needed to ensure that a sufficiently strong ultrasonic signal enters the material. However, EMAT induces the ultrasonic signal directly into the wall to be inspected. Figure 130 presents a simplified view of this technique.

7.3.3.5. Electromagnetic

(a) Eddy current testing⁸

Eddy current NDT techniques rely on magnetic induction to interrogate the materials under test. Eddy currents are closed loops of induced current circulating in planes perpendicular to the magnetic flux. They normally travel parallel to a coil's winding and flow is limited to the area of the inducing magnetic field.

(i) Conventional eddy current testing



FIG. 129. Electromagnetic acoustic transducer testing equipment (courtesy of TUV).

³ This section is based extensively on Ref. [360], courtesy of Innospection Ltd.

ECT (Fig. 131) works via the following sequence:

- Alternate current induces a primary field in a coil;
- Primary field induces eddy currents in the tube wall;
- Eddy currents induce a secondary field, which has an effect on coil impedance;
- Defects in tube wall change the secondary field and consequently coil impedance;
- Changes of coil impedance can be measured in input/output phase and amplitude.

The differential channel is ideal for detecting local defects while the absolute channel is ideal for detecting gradual defects. Figure 132 shows the eddy current signal response of a differential and absolute coil system to local and gradual defects. The differential channel shows two sharp peaks for local defects while the absolute channel defines local defects with a big peak.



FIG. 130. Electromagnetic acoustic transducer testing principle (courtesy of NDT Global) [352].



FIG. 131. Principle of eddy current testing (courtesy of Innospection Ltd) [360].



FIG. 132. Typical result of eddy current testing [360] (courtesy of Innospection Ltd) [360].

Eddy currents concentrate near the surface adjacent to an excitation coil and their strength decreases with distance from the coil, that is, the eddy current density decreases exponentially with depth. This phenomenon is known as the skin effect (Fig. 133).

The skin effect arises when eddy currents flowing in the test object at any depth produce magnetic fields which oppose the primary field, thus reducing net magnetic flux and causing a decrease in current flow as depth increases.

Eddy current field line penetration into the tube wall is essential for detection of defects on either side of the wall by means of field line changes due to inhomogeneities. The standard depth of penetration is described as follows:

$$\delta = \frac{1}{\sqrt{\sigma\mu_0\mu_r f}}$$

where

- δ is the standard depth of penetration (mm);
- σ is the material electric conductivity (Ω /mm²);
- μ_0 is the absolute permeability;
- μ_r is the relative permeability;
- f is the frequency.

Non-ferromagnetic materials have a relative and absolute permeability value of 1. Standard depth penetration of eddy current field lines depends on material electric conductivity and selected frequency.

Ferromagnetic materials, on the other hand, have relative and absolute permeability values far larger than 1. Consequently, eddy current field line depth of penetration is very limited. This is sufficient for surface defect detection such as surface breaking crack detection in CS materials.

Advantages and limitations of the eddy current method are:

— Advantages:

- Results can be obtained instantaneously;
- Can easily be automated;



FIG. 133. Eddy current field depth of penetration and density (courtesy of Innospection Ltd) [360].

- It is a non-contact method;
- Equipment is portable and suitable for field application;
- Some equipment is made dedicated to specific measurements (e.g. conductivity, crack depth).

— Limitations:

- Applicable only to conducting materials;
- If it is to be used for ferromagnetic material, item must be magnetically saturated to minimize permeability effects;
- Requires highly skilled and experienced operator;
- Applicable only for detection of surface and subsurface discontinuities.

More detail on conventional eddy current is available in IAEA Training Course Series No. 48 [361].

(ii) Eddy current array

Eddy current testing requires the development of probes with a specific coil size, frequency, defect orientation requirements, and so on; therefore, many thousands of probe designs have been developed. Although these probes can vary extensively, the number of coils and resulting data channels tend to remain constant at less than five and most often will result in one or two eddy current data channels.

This is exclusive of multiple frequencies injected simultaneously into a particular coil. This is mostly driven by simplicity of operation and the limits of typical eddy current instruments, most of which range from one to four channels. This channel limitation can create challenges for some inspections, as follows [362]:

- Probability of detection (POD) of an indication. It is difficult to ensure that small, low-channel-count probes in manual applications adequately cover the surface to result in a high POD;
- Time required to inspect a large surface area. Because of the limited footprint of low-channel-count probes, inspection of large surface areas can be long, tedious and not cost effective.

ECA probes may be used to overcome these limits. When compared to manual single channel eddy current inspection, ECAs provide dramatically increased POD for defects of interest, due to known surface coverage, sensitivity and resolution (Fig. 134).

A typical inspection result is shown in Fig. 135.

ECAs are subject to the normal strengths and weaknesses of standard eddy current technology. The difference is the number of coils read and data points generated, which can range into the hundreds in an array. The physics remain the same and will not work on non-conductive material.



FIG. 134. Comparison of (left) simple eddy current probe and (right) eddy current array [362].



FIG. 135. Typical result of eddy current array inspection [363].

- Suited for inspection of large surface areas and surface breaking indications;
- Fast. One pass can cover a wide area, typically up to 10 cm for 1.52 mm (0.06 in) coils and could be much higher with larger coils;

⁻ Advantages:

- Better confidence in results due to the known sensitivity of the coils and their overlap, which improves resolution;
- Simpler to analyse as results can be presented as a C-scan image which also allows for use of advanced image processing tools, including overlay with volumetric inspection data;
- Can be designed to fit complex shapes;
- Complex firing and reading sequence pattern can be achieved by multiplexing electronics;
- Reduced need for complex robotics;
- Very repeatable results, less operator-dependent than many surface techniques.

— Limitations:

- Usually application specific and can be limited to specific areas or geometries;
- Software set-up is complex for initial set-up as compared to other techniques;
- Solving an application usually needs more development than with a pencil probe;
- Lower sampling rate due to multiplexing;
- Higher initial investment cost.
- (iii) Pulsed eddy current

In the conventional ECT method, a sinusoid signal is used to excite the driving coil. Test specimen impedance is measured with a pick-up coil concentric to the driver coil.

In contrast to the conventional ECT method, pulsed eddy current (PEC) uses broadband pulses to excite the probe's driving coil. This stimulation pulse is scattered throughout the sample. Since field first influence is on the surface, signal time limit analysis should be used in order to gain information on underside defects.

A major advantage of PEC testing is that there is no need for direct contact with the tested object. Measurements can be performed through coatings, corrosion products and insulation materials. Compared to conventional ECT, PEC testing allows for multifrequency operation.

PEC testing may be used to measure the thickness of a coating and/or material properties (conductance or penetrability) as shown in Fig. 136. Figure 137 shows a typical probe.

PEC uses a pulsed magnetic field to generate eddy currents within the steel. The eddy currents take time to diffuse within the steel and gradually reduce in strength (Fig. 138). The strength, measured by a voltage signal at the coils of the PEC probe, drops rapidly upon reaching the end of the specimen (e.g. a pipe wall; see stage 4 of Fig. 138). This dramatic drop in strength is used to determine wall thickness, with an earlier start of signal decay indicating wall loss.

PEC probes are available to monitor wall thickness at fixed positions and thus may be used to determine corrosion rates. Figure 139 shows an example.



FIG. 136. Calculated wall thickness analysis of voltage pulse return [364].



FIG. 137. Pulsed eddy current probe [365].



FIG. 138. Diffusion of eddy currents in steel [365]

(iv) Broadband electromagnetic method

BEM is a PEC technology that can be used to assess buried piping. It can be used manually by applying a sensor to a pipe surface or via an in-line tool incorporating multiple sensors on a device that is manoeuvred through the pipe (Fig. 140). BEM produces a real time profile of a pipe enabling rapid assessment of wall conditions; post-survey processing can determine specific wall loss. No surface preparation is required. Investigators can also evaluate metallurgic changes such as graphitization. System operating frequency can be modified to suit pipe material and site conditions. Systems can scan piggable and non-piggable pipes, internal and external walls and keyhole or pothole works. Pipe components include straight sections, bends, elbows and tees. Small antennas or insertion probes can be used to assess joint condition (see Fig. 141).

(v) Meandering winding magnetometer

MWM (Fig. 142) is an eddy current based technology that uses coils embedded on a flexible film. These sensors consist of a primary winding of a specific shape, sometimes laid out in a square wave pattern and



FIG. 139. Example of PEC thickness monitoring [365].



FIG. 140. Handheld and in-line broadband electromagnetic method tools (courtesy of Rock Solid Group).



FIG. 141. Broadband electromagnetic method scan of concrete pipe joint (courtesy of Rock Solid Group).



FIG. 142. (Top left) MR-MWM array for inspection of corrosion under insulation; (top right) MWM array for crack imaging and depth sizing in stress corrosion cracking colonies; (bottom) high frequency in-line inspection tools (all courtesy of JENTEK Sensors Inc.).

sometimes in the form of rectangles with relatively long linear conductors, and a linear array of either inductive or magnetoresistive sensing elements. Capabilities include crack depth measurement in SCC colonies (closely spaced clusters), mechanical damage characterization and wall and coating thickness measurements. The sensors can be used for scanning on the outside of a pipe for imaging of corrosion or cracks through coatings, or with minimal surface preparation. The sensors can also be integrated into an in-line inspection tool. In addition, larger footprint sensors can be permanently installed for corrosion, fatigue and creep monitoring, as well as temperature monitoring through coatings/insulation. Multiple frequency methods are used with a patented model-based inverse method to correct for variable coating thicknesses and material properties and to rescale the crack or corrosion response to provide more accurate sizing. All formats of this technology are suitable for ferrous and non-ferrous alloys, both with and without coatings and insulation. Furthermore, rapid scanning at variable speeds is enabled by unique methods such as simultaneous measurement of the real and imaginary parts of the complex impedance on all channels at up to three frequencies. Also, since the instrumentation is fully parallel, there is the potential to support hundreds of channels to enable rapid wide area scanning. Data rates between 1000 and 10 000 measurements per second are possible for moderate to high frequencies; and data rates equal to the frequency at lower frequencies (e.g. five samples per second for 5 Hz) are possible. This enables scan speeds of 12.7 cm/s for low frequency internal corrosion imaging through insulation and weather jacket, or 10 m/s for high frequency in-line inspection applications.

(b) Magnetic flux leakage

MFL uses a magnet within a yoke to establish a uniform magnetic flux in the material to be inspected. Usually, strong permanent magnets are used to generate the magnetic field, but sometimes electromagnets are

used if sufficient power is available. A combination of both can even be used in order to achieve the required level of magnetization. In a defect free pipe the magnetic flux is uniform. However, if the pipe contains corrosion or erosion damage then the magnetic flux becomes distorted and a small portion of the magnetic flux is forced to 'leak' out of the pipe (Fig. 143). By placing sensors between the magnet poles it is possible to detect this local 'leakage'. Amounts of distortion and leakage are dependent on depth, orientation, type and defect position. Various combinations of volume loss can result in the same flux leakage level. As a result, MFL detection remains a qualitative rather than quantitative method of detecting defects.

Most MFL tools (Fig. 144) make use of passive Hall effect sensors to detect flux leakage as an indication of metal loss (although other sensor types such as coils, magnetostrictive and similar devices can be used). Due to the size and weight of the scanner magnets, there are limitations regarding the use of traditional MFL inspection tools. Under favourable circumstances the technique can examine pipes with a wall thickness of between 10 and 15 mm.



FIG. 143. Example of magnetic flux leakage signals from small wall thinning defects [366].



FIG. 144. Typical magnetic flux leakage probe [367].

For thicker pipes, the MFL device becomes heavy and less practical. This limitation has been overcome with the SLOFEC technology described in Section 7.3.3.5(h).

The technique can be used outside of pipes, or outside or inside of tanks for direct measurements, or commonly inside of pipework using PIGs. Various MFL based floor scanners (e.g. Floormap3Di, FloormapVS2i, MFL2000, Handscan) are available for tank floors. A typical smart PIG (for pipelines 30 cm and greater in diameter) and a floor mapper utilizing this technology are shown in Figs 145 and 146.

(c) Remote field testing

RFT may also be referred to as RFEC (remote field eddy current) or RFET (remote field electromagnetic technique). It can be used both internally and externally on a pipe to detect internal and external flaws and is especially applicable for pit detection and sizing. It is particularly useful for thick walled ferromagnetic pipe.

(i) Principle of remote field testing

Basic RFT probes (Fig. 147) have one exciter coil and one detector coil. Both coils are wound coaxially and are separated by a distance greater than twice the tube diameter. This axial distance is characteristic of RFT. If the exciter and detector were to be placed close together the detector would measure only fields generated by the exciter in its vicinity. In that case the set-up would basically be a standard ECT set-up in send and receive mode [369].

To observe RFT's unique through-wall transmission effect the detector needs to be moved away from the exciter. Actual separation depends on the application and probe manufacturer but will always be a minimum of two pipe diameters. It is this separation that gives remote field testing its name — the detector measures electromagnetic fields remote from the exciter. Although fields have become very small at this distance they contain information on full pipe wall thickness.

The simple probe in Fig. 147 is applicable for small diameter heat exchanger tubes. Probes for pipeline inspection use the same principle but contain arrays of detector coils. They are introduced to a pipeline at an open end or 'launch barrel' and can be pushed by product flow, water, hand or air pressure to the target distance. They are removed at the far end via a 'receiver barrel' or can be winched back using a simple hand or electric winch. Inspection speed is approximately 10 m/min and data are typically displayed immediately following inspection on a portable computer.



FIG. 145. Magnetic flux leakage pipeline inspection gauge (courtesy of Pure Technologies Ltd) [368].

The I-PIT tool shown in Fig. 148 contains only coils and pre-amps. It is similar to the simple heat exchanger probes except that it has 16 detector coils and interfaces to external electronics. I-PIT tools handle short lengths of pipeline ranging from 5 to 15 cm. For longer or larger diameter pipelines, the tools can be self-contained, autonomous robots that move through pipes with product flow (Fig. 149). These tools can inspect pipes from about 8 to 200 cm in diameter.

An example of an external RFT application is shown in Fig. 150. External RFT is useful for situations where a pipe must be inspected before it is taken out of service. The displayed system can inspect through coatings of up to 5 mm.

Coil dimensions will vary from manufacturer to manufacturer. Fill factor is the ratio of the effective cross-sectional area of the primary internal probe coil to the cross-sectional area of the tube interior. Although the coil fill factor can be as low as 70% it will usually be similar to EC probe fill factors: 85% or more. Lower



FIG. 146. Floormap3Di magnetic flux leakage floor mapper (courtesy of Silverwing UK Ltd; used by permission).



FIG. 147. Simple probe for remote field testing (reproduced from NDT Handbook: Electromagnetic Testing; copyright ASNT, 2005) [369].



FIG. 148. I-PIT (internal pipeline integrity tool) probe following inspection of a 150 mm pipe (courtesy of Russell NDE Systems Inc.).



FIG. 149. In-line inspection tool ready to launch in municipal water main (courtesy of Russell NDE Systems Inc.).

fill factors reduce sensitivity to small discontinuities but do not otherwise affect RFT data quality. The ability to function with low fill factors makes RFT attractive for pipes with internal coatings, liners and tight bends.

RFT probes often contain arrays of receiver coils. The coils are connected to an RFT instrument by a coaxial cable, where the outer conductor is used to shield inner conductors from ambient noise. The cable is usually housed in a stiff plastic tube that lets the probe be pushed into a heat exchanger tube or pipe for long distances.

For a remote field probe, there are two distinct sensing zones with a transition zone between them (see Fig. 151). The zones are the direct field zone, transition zone and remote field zone.

As detector coil distance from the exciter coil is increased, the dominant field energy changes from direct coupled (between exciter and detector coils inside the tube) to energy that is coupled to the detector coil primarily by transmission through the tube wall.



FIG. 150. E-PIT (external pipeline integrity tool) remote field testing for internal pits (courtesy of Russell NDE Systems Inc.).



FIG. 151. Zones in remote field testing. Profiles of B field just inside and outside pipe wall indicate direct field region, transition and remote field zones (reproduced from NDT Handbook: Electromagnetic Testing; copyright ASNT, 2005) [369].

Between these two distinct zones, there is a transition zone where the direct coupled energy and the indirect coupled energy are comparable in magnitude. The location of the transition zone changes with frequency, wall thickness, permeability and conductivity.

In an idealized situation (infinite AC sheet over a conducting half space), eddy current density in the case of conventional eddy current techniques decays exponentially with depth. This phenomenon, called the skin effect,

limits the application of conventional ECT to surface or shallow heterogeneity detection. The RFT technique seemingly violates the skin effect limitation in that it is equally sensitive to inside surface and outside surface discontinuities.

(ii) Remote field testing and eddy current testing

Inspection coil impedance is measured in typical ECT instruments. Usually the coil is part of a bridge circuit that becomes unbalanced as it passes over changes in material thickness, permeability or conductivity.

Discontinuities are characterized and sized by signal phase rotation and attenuation as compared to a reference standard. The test coil in ECT can be an energized coil or it can be a passive coil that receives its energy from a separate energized coil in close proximity (send and receive configuration). Common coil configurations are absolute or differential coils; axial or radial coils; and bobbin or pancake coils.

RFT has many similarities to ECT but there are also major differences [369]:

- (1) In RFT, the exciter coil is always separated from the receiver coil or coils by at least two tube diameters. As such, RFT coils are always in a send and receive configuration.
- (2) In RFT, energy from the exciter coil passes through the tube wall twice, once when leaving the exciter and again when passing back through the wall at the detector.
- (3) Sensitivity to discontinuities on the outside of a tube is reduced in ECT, whereas RFT maintains almost equal sensitivity to discontinuities either inside or outside the tube.
- (4) RFT systems measure signal phase and amplitude. ECT systems may measure the same quantities in send and receive configurations, or may measure test coil impedance.
- (5) ECT probes are sensitive to changes in proximity of the test coil to the tube surface. This change is known as probe wobble as the probe passes through the tube, it can be pushed off centre by internal scale or dents. Even if the tube is clean, the ECT probe can wobble unless it is centred with mechanical guides.
- (6) RFT probes are relatively insensitive to probe wobble and are forgiving if undersized or pushed to one side of the tube.
- (7) Because of the much lower test frequencies used for RFT in steel (and because phase measurement usually requires at least one time period of the excitation signal), RFT probes must be moved more slowly than ECT probes. The RFT probe must be near the smallest discontinuity required to be detected for at least one cycle in order to detect it.
- (8) Absolute coils for both RFT and ECT are sensitive to temperature variations over the tube length.
- (9) In steel tubes, RFT is more sensitive to circumferential cracks that interrupt magnetic flux lines; although a circumferential eddy current also exists and gives RFT some sensitivity to axial cracks and notches, it is not the dominant field. ECT bobbin probes are more sensitive to axial cracks in tubes, which interrupt the eddy currents and have no sensitivity to circumferential cracks.
- (10) Because of its so-called through-transmission nature, RFT can examine thicker materials than ECT.
- (11) Because it is commonly used for steel and cast iron, RFT is generally carried out at a lower frequency than ECT.
 - (iii) Examples of inspection results

Typical inspection results for buried piping are shown in Fig. 152.

(iv) Remote field testing and magnetic flux leakage

With an MFL probe, the energy source is an axially aligned magnetic field (as with an RFT probe). Discontinuities are detected by the probe as some magnetic flux lines leak out of the pipe and are detected by passive coils or sensors passing though the leakage field [369].

This arrangement is similar to that for RFT except that RFT probes generate an AC field whereas MFL testing uses a DC field. When pick-up coils are used, the RFT probe itself does not need to be moving to measure wall thickness, because the excitation is alternating [369].



FIG. 152. 60 cm remote field testing tool inspection results (courtesy of Russell NDE Systems Inc.).

The RFT signal is likely to offer additional information because both signal phase and amplitude can be analysed. In contrast, only the amplitude of the MFL signal is available. Consequently, RFT provides two pieces of information, usually enough to permit calculation of tube wall thickness [369].

(d) Alternating current field measurement

ACFM is an electromagnetic technique using induced uniform currents and magnetic flux density sensors to detect and size surface breaking discontinuities without calibration. It is used extensively for weld condition inspections. Uniform means that, at least in the area under the probe, current lines in the absence of a discontinuity are parallel, unidirectional and equally spaced [369].

Surface breaking discontinuities perturb the induced current and magnetic flux density. Relative, rather than absolute, amplitudes of components of the magnetic flux density are used to minimize variations caused by material properties, instrument calibration and other circumstances. These relative amplitudes are compared with values in sizing tables produced from a mathematical model to estimate discontinuity sizes without the need for calibration using artificial discontinuities such as slots.

The required locally uniform magnetic field is induced using one or more horizontal axis solenoids, with or without a yoke (Fig. 153).

Figure 154 shows the effect of a surface breaking discontinuity on the magnetic field. The discontinuity diverts current away from the deepest parts and concentrates it near the crack ends. The current distribution produces a broad dip in magnetic field along the discontinuity with the minimum value coinciding with the deepest point. The amplitude of this dip is larger for a deeper discontinuity of a given length. At the same time, concentration of current lines around the discontinuity ends produces small magnetic field peaks.

Figure 155 shows components arranged in a typical ACFM test. The exact parameters used in a probe vary according to application. Larger dimensions are used where possible because they give the most uniform field and allow the two sensors to be wound concentrically, which gives clear symmetric loops in the butterfly plot. In probes designed for tight access applications or for higher sensitivity, smaller dimensions are used.

(i) Effect of coating thickness

An advantage of the uniform field used in ACFM is that it results in a relatively small reduction in signal intensity with probe lift-off. Consequently, ACFM can detect cracks through several millimetres of non-conductive coating.



FIG. 153. Induction coils above metal structure to be inspected [370].



FIG. 154. Eddy current flowing around a discontinuity [370].

(ii) Deep crack limit

Any technique that uses induced currents to interrogate surface breaking discontinuities will, for sufficiently deep discontinuities, face the problem that any further increase in discontinuity depth has no effect on the current distribution on the face of the discontinuity.

Therefore, no information can be gained about where the bottom of the crack is. This limiting discontinuity depth depends on the probe design — in particular, on the size of the inducing magnetic field. Figure 156 shows experimental results for the rate of change in B_x signal amplitude.



FIG. 155. Typical alternating current field measurement (reproduced from NDT Handbook: Electromagnetic Testing; copyright ASNT, 2005) [369].



FIG. 156. Rate of increase in magnetic flux density (B_x) minimum with increasing slot depth (reproduced from NDT Handbook: Electromagnetic Testing; copyright ASNT, 2005) [369].

(iii) Limitations

ACFM uses a uniform input field to allow comparison of signal intensities with theoretical predictions. A uniform field has advantages and disadvantages compared with conventional ECT [369]:

- Advantages:
 - Ability to test through coatings several millimetres thick;
 - Ability to obtain depth information on cracks up to 25 mm deep;
 - Easier testing at material boundaries such as welds.
- Disadvantages:
 - Lower sensitivity to small discontinuities;
 - Signals obtained from nearby geometry changes (such as plate edges);
 - Dependence of signals on discontinuity orientation relative to probe.

(iv) Alternating current field measurement arrays

Conventional ACFM probes contain a field inducer and one pair of sensors. In its simplest form an ACFM array probe contains multiple sensor pairs operating with a single (larger) field inducer.

A linear array can then be swept over a component to inspect the scanned area. Introduction of array technology allows inspection of larger areas in a single scan (Fig. 157).

A single field inspection is limited to a particular defect orientation (predominantly oriented along the scan direction). To overcome this it is possible to incorporate other field inducers into the array probe to allow fields in other orientations. This is useful in situations where crack orientation could be unknown or variable. In this case additional sensors are incorporated to take advantage of additional input field directions.

To best use an array probe it is necessary to switch through sensors as quickly as possible to allow rapid inspection. There are inherent limitations to this, including switching settling times, data transfer rates and limitations in sampling of a 5 kHz signal.

ACFM array probes have been deployed for underwater inspections of welds for nuclear steel storage vessels in France [372].

(e) Impact methods

Controlled impact to concrete pipe surfaces can generate stress waves within pipe walls that can be detected by one or more sensors on the pipe surface spaced a known distance away. Concrete properties and locations of defects can be determined based on stress wave velocity and dominant response frequencies. Two types of stress wave analysis currently in use in different forms are impact echo (IE) and spectral analysis of surface waves (SASW). IE is used to identify delamination at the interface of the concrete core with either the steel cylinder or coating. SASW is based on the premise that microcracking and cracking of concrete reduce its modulus; it is used to determine wave velocities in concrete, from which the concrete modulus is determined.

An IE test system is composed of three components: an impact source; a receiving transducer; and a digital processing oscilloscope or waveform analyser that is used to capture the transient output of the transducer, store digitized waveforms and perform signal analysis [373]. A transient stress pulse is introduced into the concrete by mechanical impact on the surface and propagates along spherical wave fronts as P- and S-waves. The sound pulse or compression wave is reflected from the backside of the concrete, internal reflectors (e.g. cracks), or from other objects that may cause changes in acoustic impedance and material density along the propagation path. Figures 158 and 159 present the IE principle. Information is obtained related to the complete concrete, or a significant volume of it (i.e. signal cannot be focused as with the ultrasonic pulse-echo method).



FIG. 157. Schematic showing different coverage from manual and array probes (courtesy of TSC Inspection Systems) [371].



FIG. 158. Impact echo impactor equipment (courtesy of Olson Instruments) [374].



FIG. 159. Impact echo results: A single sharp peak indicates sound concrete (courtesy of Olson Instruments) [374].

Reflections or echoes are indicated by frequency peaks in resultant spectral plots that are used to locate discontinuities. Method applications include determining thickness and detecting flaws in plate-like structural members; detecting flaws in beams, columns and hollow cylindrical structural members; assessing quality of bond in overlays; crack depth measurements; and detecting degree of grouting in post-tensioning ducts.

SASW is used in testing concrete and in geophysical surveys. It requires accessibility to one surface. A mechanical impact on the concrete is used to generate surface waves of different wavelengths. These are picked up by transducers placed at fixed distances from the impact source and the velocity of each wavelength component is evaluated. Transducers are placed in line with the impact source and with spacing determined by the depth to be measured. In the case of a massive concrete element this may require access to a large surface area. The technique uses dispersion of surface waves to produce a surface wave velocity cross-section of the subsurface. The velocity of the Rayleigh wave is related to shear modulus (stiffness) and material density. Shear wave velocity profiles are determined from experimental dispersion curves (surface wave velocity versus wavelength) obtained from SASW measurements. Once shear wave velocity profiles are determined, shear and Young's moduli of the

materials can be calculated. The method is well suited for testing large surfaces, layered systems, condition survey of liners of concrete tunnels, mapping of subsurface cavities and for determining depths of foundations or the condition of underlying material. Figure 160 provides a schematic of the test set-up and use of wavelength to investigate different depths of a layered system.

(f) Remote field transformer coupling

RFTC, also referred to as remote field eddy current/transformer coupling, is a method developed for in-line inspection of lined cylinders (concrete pressure pipes) and uses low frequency electromagnetics to interrogate the prestressing windings.

The method is based on the RFEC (RFT) technique. Using the RFT technique on a PCCP pipe induces an additional inductive interaction with the prestressing wires called transformer coupling. The combined result is an effective inspection technique for PCCP.

In Fig. 161, prestressing wires are shown above the steel and concrete layers instead of encircling them. Part (1) of the figure shows the important through-transmission effect of the RFT path, which allows interaction with the prestressing wires from inside the steel lined pipe. Here the detector is not underneath the windings so only the RFT coupling remains. In part (2), both coils are beneath the windings so the strong transformer coupling between the coils is superimposed onto the weaker background RFT path.

The transformer coupling (TC) induces measurable currents in the prestressing windings. These currents generate an additional field similar to that of a long solenoid coil, provided that the windings form a closed coil without any breaks. The TC effect provides an additional energy path between the exciter and detector coils. When both coils are beneath the prestressing windings, TC becomes the dominant coupling path.

In the case of a broken prestressing wire the TC effect coupling is disrupted, changing the detected signal. RFT methodology still remains important because the intercoil spacing must satisfy the remote field conditions (i.e. the overall external energy coupling path dominates the direct coupling internal to the pipe).

In practice RFTC measures the results of the complicated vector interplay between both coupling paths and has been shown experimentally to be sensitive to both single and multiple breaks.

RFTC differs from standard remote field inspection in several ways that make it particularly suited to the additional requirements of concrete pressure pipe (CPP) inspection:

- (1) RFT probes traditionally use exciter coils with large fill factors to produce uniform fields for high resolution scans. A large fill factor is impractical in CPP because of both required coil diameter and limited access;
- (2) Conventional RFT probes use detector coils with large fill factors, or, if circumferential detail is required, an array of smaller coils is used;
- (3) RFT is most effective at an intercoil spacing of 2–3 pipe diameters. In CPP inspection the TC effect enhances coupling along the indirect coupling path, which in some cases allows use of shorter tools than regular RFT probes [376].



FIG. 160. Spectral analysis of surface waves test set-up, sample application (use of different wavelengths to examine different depths of layered system) and field equipment set-up (courtesy of GEOVision) [375].

Typical results from an RFTC inspection are shown in Figs 162 and 163.

(g) Low frequency electromagnetic technique

LFET can be used to detect flaws by inducing a low frequency electromagnetic field into the pipeline to be inspected (Fig. 164).

Any pipe flaw will distort the returning field, which is picked up by a sensor. These data are analysed to determine the test material condition. A waveform will show a signal increase from the metal baseline to indicate where wall loss has been detected.

LFET is a dry non-contact method that can detect ID and OD defects in ferrous and non-ferrous materials. LFET inspections are able to detect pitting and erosion/corrosion. An example of LFET inspection is shown in Fig. 165.



FIG. 161. Remote field testing and additional transformer coupling energy coupling paths in prestressed concrete cylinder pipe [376].



FIG. 162. Typical amplitude (above) and phase logs (below) showing inspection results from a defect free test sample and one with five broken wires [376].



FIG. 163. Typical complex plane remote field transformer coupling inspection results [377].



With no flaw, sensor sees uniform magnetic field as probe sweeps across the plate.



FIG. 164. Principle of low frequency electromagnetic technique testing (courtesy of Testex Inc.) [378].

(h) Saturation low frequency eddy current

The principle of SLOFEC is the same as that of MFL; however, SLOFEC uses active eddy current sensors to detect flux leakage. Eddy currents in steel have a small penetration depth due to high relative magnetic permeability. This limits eddy current penetration to the outer surface. This so-called 'skin effect' is reduced by inducing a magnetic field within the pipe wall. This allows eddy currents to penetrate deeper, up to the full wall thickness. The magnetic saturation not only creates a low permeability and uniform flux, it also suppresses the usual local

material permeability variations and reduces noise levels, which would otherwise prohibit proper functioning of flux sensing systems. Figure 166 shows sample SLOFEC equipment and the principle involved, and Fig. 167 a comparison between SLOFEC and MFL sensitivity. SLOFEC may also be deployed using in-line systems.

(i) NoPig pipeline inspection system

The NoPig pipeline inspection system analyses the magnetic field of a pipeline from above ground. To create this field an inspection current is induced between two contact points on the pipeline (preferably existing points such as CP test posts). The current is a superposition of a 9 Hz low frequency (LF) and 620 Hz high frequency (HF). The LF fills up the pipe wall cross-section while the HF only travels on the outer side of the pipe.

Normally, the magnetic field of a pipe without a defect consists of concentric circles around its geometric centre. The field is equal to the magnetic field from the same current flowing through the pipe centreline. In case of metal loss the current distribution will be influenced by the defect. Defects on the outer side will influence both the high and low frequency part of the current distribution while defects on the inner side affect only the LF current. In both cases the current axis (LF, HF or both) will shift, resulting in a magnetic field change (Fig. 168). Metal loss can be detected by measuring this change above ground [377–381].



FIG. 165. Low frequency electromagnetic technique inspection results for a superheater tube with wet magnetite deposits (courtesy of Testex Inc.) [378].



FIG. 166. SLOFEC inspection equipment technology principle (courtesy of Innospection Ltd) [379].



FIG. 167. Sensitivity comparison of magnetic flux leakage and saturation low frequency eddy current (courtesy of Innospection Ltd) [379].



FIG. 168. Magnetic field sensor array above ground [381].

7.3.3.6. Radiography

(a) Conventional radiography

Radiographic testing (RT) is an NDT method that uses penetrating radiation. It is based on differential absorption of radiation by the part under inspection. In this inspection the radiation source can be from radioactive sources, typically iridium-192, cobalt-60 or caesium-137, which emit gamma rays, or from a specially built machine that can emit X rays. The former is known as gamma radiography, whereas the latter is referred to as X ray radiography.

RT is able to examine the volume of a specimen, as opposed to only revealing surface breaking defects. It produces a radiograph of a specimen, showing changes in thickness, defects (internal and external), assembly details and other features.

Figure 169 shows a typical set-up in radiographic testing.

During RT X rays or gamma rays penetrate through the material under inspection. While traversing the material, the radiation experiences modification by the internal material structure via absorption and scattering processes. If the internal structure is homogeneous, absorption and scattering will be uniform and radiation that escapes the material will be of uniform intensity.


FIG. 169. Typical set-up in radiographic testing (adapted from Ref. [382]).

This radiation is then recorded by a suitable recording medium, typically radiographic film. When the film is processed, a uniform dark image will appear on the film that indicates the homogeneity of the material tested. The situation is different for cases of materials containing discontinuities or differences in thickness. In general, absorption of radiation by a material depends on the effective thickness through which the radiation penetrates.

Discontinuities such as cracks, slag inclusions, porosity, lack of penetration and lack of fusion reduce the effective thickness of the material under test. Thus, the presence of such discontinuities causes radiation to experience less absorption as compared with that in areas with discontinuities. As a result, in areas containing discontinuities more radiation escapes, is recorded by the film and forms a dark image representing the internal material structure.

The appearance of radiographic images depends on the type of discontinuities encountered by the radiation. Cracks, for example, will produce a fine, dark and irregular line, whereas porosities produce dark round images of different sizes.

Some discontinuities in a material, such as tungsten inclusions in steel, have a higher density than their surroundings. In this case, the effective thickness that needs to be traversed by radiation is somewhat greater (more radiation is absorbed in this area as compared to other areas). As a result the radiation intensity that escapes after traversing this area will be lower than that for other areas, giving a lighter image bearing the shape of tungsten inclusions inside the material.

Increasingly, radiographic film is being read and digitized for viewing and archiving, or filmless imaging plates are being used to record images for easier digitization (computed radiography). Radiographic techniques called computed tomography (CT) can also be used to generate slice-by-slice 3-D scans of items of interest. In an industrial context CT scanning can be used for flaw detection, failure analysis, metrology, assembly analysis and reverse engineering applications.

RT is widely used throughout industry. Its capacity to produce two dimensional permanent images makes it one of the most popular NDT methods. Examples of RT inspection devices and results are shown in Figs 170 and 171.

Radiation used for radiography does present a potential hazard to radiographers and members of the public. Due to its hazardous nature, the use of radiation, including for industrial radiography, is strictly controlled by regulatory authorities. The requirements imposed by such authorities make it one of the most expensive NDT methods. IAEA guidelines on industrial radiography safety are included in IAEA Safety Reports Series No. 13 [383]. Advantages and limitations of RT are:

- Advantages:

- Applicable to almost all materials;
- Produces permanent images that are retrievable for future reference;
- Capable of detecting surface, subsurface and internal discontinuities;
- Capable of exposing fabrication errors at different stages of fabrication;
- Much equipment is portable.

Limitations:

• Radiation used is hazardous to workers and public;



FIG. 170. Flaw detection system on a 1020 mm diameter pipeline (1: X ray source; 2: linear diode array; 3: pipeline; 4: positioning mechanism; 5: marker) [382].



FIG. 171. Example of radiographic testing result: X ray image of a weld of a pipe 1020 mm in diameter, with a total thickness of steel of 24 mm [382].

- Expensive (cost of equipment and accessories related to radiation safety are relatively expensive);
- Incapable of detecting laminar discontinuities;
- Some equipment is bulky;
- For X ray radiography, it needs electricity;
- Requires two sided access (film side and source side);
- Results are not instantaneous (requires film processing, interpretation and evaluation);
- Requires personnel highly trained in radiography and radiation safety.
- (b) Real time radiography

RTR uses advanced X ray generation and detection technology to produce true X ray images which are displayed, analysed and digitally stored as they are being captured. The operator can scan relatively large areas of pipes (100–150 m of pipe per day on average) to look for discontinuities, welds or damaged areas (Fig. 172).



FIG. 172. Real time radiography equipment (courtesy of TechCorr USA Management, LLC.).

Three types of detector are generally available. The first detects transmitted radiation through the pipe via solid state detectors that directly create an image on a computer screen. The second is a plate that phosphoresces when radiation hits it, forming an image via photodiodes. There is also a flexible detector plate available in which incident radiation causes molecular polarization in a chemical layer and the final image is obtained by scanning the plate. The advantage of RTR is that the detectors are far more sensitive than conventional film. As a consequence it is possible to reduce both the exposure time and size of the source. This can reduce the size of exclusion zones when carrying out inspections.

7.3.3.7. Spark tools

A spark tool (Fig. 173), also sometimes referred to as a holiday detector, porosimeter or jeeper, can be used to identify coating holidays. It is essentially a steel brush with a voltage applied to it. When this brush is isolated from a pipe surface due to coatings or linings there is no 'connection' between the charge on the brush and the pipe wall. However, as soon as there is a holiday in the coating or lining the voltage on the brush discharges to the pipe wall through the holiday. This can be detected by a small spark and an audible cracking sound. A number of spark tools are commercially available and sample standards include ASTM G62-07 [384] and AS 3894.1 [385].

7.3.3.8. Laser profilometry/3-D scanning

Laser profilometry is a non-contact NDT technique that uses single or multiple low-powered lasers to profile an object's surface, including any flaws. It can provide a high resolution three dimensional profile of the test surface and a monochrome 'laser-video' image of the surface.

It utilizes a light source (in most cases a diode laser), imaging optics and a photodetector to generate a signal that is proportional to the height of a target surface (such as a pipe). To generate the 3-D surface image, the sensor scans in two dimensions, generating a helical set of radius data representing the surface topography. Software then generates a user-friendly colour surface image. Figure 174 shows the technology used.

A commercial 3-D laser pipe scanning system is shown in Fig. 175. Published accuracy is up to 0.03 mm [386].



FIG. 173. Spark tool (courtesy of Rock Solid Group).



FIG. 174. Laser profilometry principle (courtesy of Quest Integrated Inc.).

7.3.3.9. Microwave techniques

Microwave NDE technology has been developed to inspect dielectric materials such as rubber expansion joints and non-metallic piping such as FRP, HDPE and fibreglass. The technology can assess condition and inspect through coatings and paint, and can be used to quickly detect and size cracks, voids, pitting, porosity and joint disbondment. The full thickness of most non-metallic materials can be scanned. Microwaves do not penetrate appreciably into metals or conductive materials and so are only applicable for surface inspections for such material (e.g. surface cracking and surface corrosion depth). Figure 176 shows typical equipment.

Microwaves are radiated from the transducer to the specimen being tested. A detectable signal is returned at each interface where the dielectric constant changes (e.g. where there are delaminations, cracks, holes, impurities or other defects). The transducer may be moved relative to the specimen at any desired speed and the scanning speed need not be uniform. No couplant is required.

Once the data have been collected, software allows the image to be manipulated to enhance features. Changes in defect size can be trended over time, allowing for determination of growth rate and ultimate service life.



FIG. 175. HandySCAN 3-D scanner and Pipecheck application software (courtesy of Creaform).



FIG. 176. Microwave non-destructive evaluation equipment (courtesy of Evisive Inc.).

7.3.3.10. Direct techniques specific to concrete pipe inspections

(a) Electrical continuity testing

Wire continuity testing provides an accurate account of the number and location of broken wires in a PCCP pipe without full excavation and without damaging the pipe. The technique involves partial excavation, removal of the mortar coating at the pipe's crown level and measurement of wire resistance with a multimeter (Fig. 177).

Continuity of the wire for non-shorting-strap ECP can be determined by measuring the resistance between adjacent wire wraps. A broken wire results in a high measured resistance between adjacent wire wraps. Wire continuity measurements require the excavation of a 60 cm width on the top of the pipe and localized removal of the coating at its crown to expose the wires in a strip along the full length of the pipe and approximately 5 cm wide circumferentially [330].

Measurement of electrical resistance between exposed portions of adjacent wraps can identify wire breaks at any location around the pipe circumference. Wire continuity testing requires a digital multimeter with test leads, equipment to remove a strip of coating along the top of the pipe to locally expose the wires and equipment to clean the prestressing to obtain a bright, clean metal surface for electrical connection between the wire and the



FIG. 177. Wire continuity testing (courtesy of Water Research Foundation; reproduced with permission) [330].

multimeter test lead. Care must be taken to minimize damage to the wires during removal of the coating strip. Wire continuity measurements cannot be performed on ECP with shorting straps or LCP due to the electrical continuity of the wires provided by the shorting strap or the steel cylinder, respectively.

(b) Electromagnetic inspection⁹

Electromagnetic (EM) inspection is an NDT technology that can detect and estimate the number of broken wires in PCCP. The location and number of broken wires are predicted by analysis of distortions in EM signals collected during inspection. EM tools have been developed for pipes ranging in size from 40 cm to 6.4 m. Inspections can be internal or external to the pipe with the system dewatered or in service.

Equipment required consists of an exciter, detector, data acquisition system, power supply (batteries) and odometer — all mounted on a tool that travels inside or outside the pipe. Figure 178 shows a variety of possible combinations.

The results of EM inspection can be used directly to assess pipeline condition and obtain a measure of remaining service life when used jointly with failure margin analysis to determine how close a distressed pipe with a number of broken wires and a maximum internal pressure is to failure.

Prediction of distress level has been subject to the uncertainties involved in interpretation of signal distortions. Uncertainties are exceptionally higher for ECP without shorting straps. Unlike pipes with shorting straps that show a linear relationship between the actual number of broken wires and signal distortion, pipes without shorting straps show large distortion for a single broken wire and lower resolution as the number of broken wires increases. Another source of uncertainty is steel cylinder thickness. EM waves are affected by steel cylinder thickness, which typically varies along the pipeline length and near bends, tees and bulkheads. Thicker steel cylinders may completely obscure signal distortions. Absence of accurate design information and pipe location can adversely influence inspection results. Additional uncertainties have been related to steel cylinder EM properties and methods of anchoring the prestressing wire to the concrete core and cylinder. The presence of shorting straps and pipe design properties must be known prior to conducting the inspection. The appropriateness of EM inspection for PCCP without shorting straps should be evaluated after a review of calibration results that show the actual number of broken wires and corresponding measure of signal distortion.

External EM inspection improves resolution as it allows the use of higher frequency waves because signals do not need to pass through the steel cylinder. HF waves provide an improved estimation of the number of wire breaks near pipe joints and away from the joints.

(c) Galvanostatic pulse measurement (concrete reinforcement)

In galvanostatic pulse or linear polarization measurement a short time anodic pulse (typically 5–10 s) is applied galvanostatically to concrete reinforcement and resulting changes in potential are monitored. Potentials are measured with a reference electrode and high impedance voltmeter (Fig. 179). When current is applied, there is a

⁹ Section mainly developed based on Ref. [330].





Cycle Style Tool

Robotic Tool



Free Swimming Tool

FIG. 178. Electromagnetic concrete pipe inspection tools [387].



FIG. 179. GalvaPulse device principle (courtesy of Germann Instruments).

potential drop IR_{o} as well as a change in potential due to reinforcement polarization, IR_{p} . Polarization resistance of the reinforcement R_{p} is calculated by curve fitting to the transient portion of potential data. Corrosion rates can be estimated based on the Stern-Geary equation that relates polarization resistance to corrosion currents.

For concrete pipe the method can be used to detect where corrosion of reinforcement wire is more likely and further inspection is required. Direct access to the pipe is required as well as removal of any dielectric coatings.

(d) Concrete petrographic analysis

Petrographic analysis of mortar coatings can help determine the quality and condition of the coating after years of service. Petrographic analysis includes a microscopic examination of polished and thin sections and in some cases, scanning electron microscopy and energy dispersive X ray spectroscopy (SEM/EDXS). A sample standard for such examinations is ASTM C856 [388].

Because soil is frequently contaminated with chlorides or pipes could be close to a source of them (sewage, sea water, etc.), and chloride attack is one of the most frequent deleterious mechanisms in reinforced concrete elements, tests that determine the amounts of soluble chlorides present in concrete can be used to help estimate remaining service life. One needs access to the concrete surface to take powder concrete samples; however, obtaining the samples is a quick process and chloride measurements can be made in site. Figure 180 shows a profile grinder used to take concrete powder samples and sample results of chloride concentration versus depth for a highway bridge using two test methods.

(e) Joint inspections

Concrete pipe joints are often inspected visually for obvious signs of grout loss, cracking or damage. Recently, other techniques such as BEM analysis (see Section 7.3.3.5(a)(iv)), have been developed.

7.3.3.11. Remote inspection using pipeline inspection gauges and robotic inspection equipment

The oil and gas industries have for many years carried out remote direct inspections of their pipelines using pipeline inspection gauges (PIGs). PIGs are tools that are sent down pipelines and are typically propelled by the pressure of the product flow in the pipeline itself. They may be free flowing or tethered. A qualification standard has been developed by the API (Standard 1163 [286]).

PIGs were initially developed to clean straight sections of large diameter pipework. However, modern PIGs (i.e. smart PIGs), such as those shown in Figs 181 and 182, are capable of carrying out a variety of tasks including remote visual, UT, acoustic (leak detection), MFL, SLOFEC, ECT and RT inspections.

These inspections are all relatively tolerant to surface conditions. Removal of loose and excessive debris prior to inspection is generally sufficient. MFL and SLOFEC techniques can only be applied to low alloy CS components which have a high magnetic permeability.

The efficacy of these techniques (i.e. MFL, SLOFEC and RTR) is not proven for large diameter piping with wall thickness greater than 15 mm. For these sections, which can have a diameter of up to 91 cm, there is a need to



FIG. 180. (Left) Profile grinder and (right) chloride concentration versus depth analysis; results shown for rapid chloride test for water-soluble chlorides and rapid chloride water test for acid-soluble chlorides (courtesy of Germann Instruments).



FIG. 181. Ultrasonic smart pipeline inspection gauge application (courtesy of Quest Integrity Group).



FIG. 182. Example of a gas pipeline inspection gauge [339]¹⁰.

have either a high energy radiation source or a very large magnet to fully saturate so much material. This factor will probably determine which NDT technique is most appropriate.

Notwithstanding this, decisions to deploy smart PIGs should be made on a case-by-case basis.

Self-propelled robotic tools or pipeline crawlers that can travel in filled, partially filled or empty pipelines are increasingly becoming available. These tools often have single point access capabilities, allowing them to be inserted into a pipe at a single location (e.g. a removed block valve; see Fig. 183) and retrieved from the same location. Such tools allow inspection of piping that was traditionally considered 'un-piggable'. The sensors used are similar to those on smart PIGs.

Some guidelines on specific safety precautions to take with radiography using pipeline crawlers are included in section 6.8 of Ref. [383]. The concern is that pipeline crawlers are not visible from outside the pipe and thus it is essential that suitable warning signals are given to any personnel in the area with respect to the moving radiation hazard.

FME is also of concern at nuclear power plants whenever tooling or a device such as a PIG is placed inside of a normally closed plant system. Such PIGs should have an engineering evaluation regarding the acceptability of their use and the potential for and consequences of FME prior to use. Refer to IAEA Nuclear Energy Series No. NP-T-3.22 [390] for more details.

7.3.3.12. Direct leak detection

Direct leak detection methods (including direct visual inspection, bubble testing, etc.) were covered previously with indirect methods in Section 7.3.2.6.

¹⁰ Tool consists of a drive unit, instrumentation unit and centre section with an electromagnetic and flux leakage sensors.



FIG. 183. Robotic tool inserted at removed valve (courtesy of Inspectioneering LLC) [389].

7.3.4. Pipe casing inspections

Commonly used above ground tools such as CIPS, PCM, DCVG and ACVG are often used as a first step to assess condition at cased crossings. These tools can help to identify coating holidays near casing ends and/or the presence of a shorted casing. The ability to find the exact location within a casing may be limited depending on conditions.

Electrical isolation between the casing and carrier pipe can be assessed via the following methods:

- Potential surveys: Pipe-to-soil and casing-to-soil readings if both within 100 mV of each other, potentially shorted.
- Internal resistance test: Measures potential difference between pipe and casing with and without current and calculate resistance; Low resistance (< 0.01Ω) indicates a metallic short.
- Cycle rectifier: If casing is isolated from pipeline, casing-to-soil should not shift with cycling of rectifier.
- Casing depolarization: Pipeline depolarization should have little or no effect on casing potentials.
- Pipe/cable locator: A pipe trace with transmitter set-up between pipe and casing can approximate the location
 of a short.

Further inspections or assessments can be done using in-line/robotic methods, pressure tests or indirect methods such as GWUT. Inspections for the pipe casing would typically focus on identifying no shorts between casing and carrier pipe, no water ingress and the presence/level of fill material.

7.3.5. Submerged pipe inspection

Piping located in vaults can become submerged due to known plant configurations or inadvertently when vault covers or surfaces leak due to rain or groundwater intrusion. Submerged piping should be visually inspected when the water has been removed from its vault. The visual inspections should be capable of detecting loss of material or cracking on bare metal surfaces as well as the condition of the coatings when applied. Consideration should be given to more frequent inspections of submerged piping when it has not been coated, or the coatings are not qualified for submerged service.

7.3.6. Buried tank inspection

When a buried tank is uncovered or entered for any reason, it should be visually inspected for evidence of corrosion or damage. Inspection results, photographs and videos should be documented. Inspection methods are similar to those of piping surfaces (e.g. visual, coating inspections, UT, MT, eddy current) Additionally, the inspection should include the results of leak detection.

Typically, storage tanks suffer from corrosion on the undersides of floor bottoms. Often this will be localized pitting. Sometimes larger areas may be corroded, for instance, at places close to the tank shell. Having access only to the top surface of the floor this corrosion cannot be found by visual inspection. Inspection methods are needed that can detect underside corrosion from the topside and give a full floor coverage. Self-propelled floor scanners and portable instruments have been developed using MFL (Section 7.3.3.5(b)) and SLOFEC (Section 7.3.3.5(h)) technology to perform such inspections of tank floors and other inner plates [391]. Scanning surfaces should be clean and free from debris (particularly from corrosion products that may have fallen from tank roofs). Surface roughness may cause a vibration that can affect signal to noise ratios. In some cases laying a thin sheet of plastic over the scanning surface can alleviate this. Rough areas such as weld spatter or weld repairs that have been ground flush may give large false indications.

Other robotic tools for inspection of in-service tanks have been developed. Automated crawlers or robots equipped with UT, laser profilometry, eddy current or ACFM probes can be used for tank floors, shells or welds. Some devices require ferrous tanks for their magnetic attachment systems and some can be deployed in a submerged environment.

Flash thermography is a relatively new technology that is becoming available for tank inspections. A pulse or flash of heat is applied to a structure's surface and surface temperature changes over time are evaluated with an infrared camera to determine if a structure is sound, or if defects such as wall thinning, voids or delaminations are present. Defects act as insulators and slow down heat flow.

The National Leak Protection Association (NLPA) has issued recommendations on inspecting buried lined steel tanks using a video camera [392]. Other sample applicable tank inspection standards include API 653 [285], ASTM G158 [214], NACE SP0288 [303], NLPA 631 [393], STI SP001 [311], STI SP131 [312] and PEI RP900 [308]. EPRI has also issued guidelines for tank inspections [297].

It should be noted that the approach to above ground and underground tank inspections can be somewhat different depending on the jurisdictional regulatory environment. Underground tanks are more heavily regulated, often requiring, for example, at least one secondary containment system. Regulations and thus inspections are often focused on quick leak detection (and the systems designed to do so) and rapid tank repair. Inspection guides and approaches for above ground tanks, on the other hand, can focus more on the state of the physical tank, alarms, vents and support structures themselves, as well as any installed methods of leak detection. Above ground tank standard API 653 [285], for example, provides methods for tank roof, shell, bottom and foundation evaluation, and STI SP001 [311] provides inspection and evaluation criteria, including details on inspection methods such as visual, MFL, UT, MT, PT, radiography and leak testing methods.

7.3.7. Weld inspections

Completed welds are required to be examined during construction to verify conformance to design requirements. When performing direct piping inspections as part of in-service inspection and monitoring, weld areas should be given special attention as they are an area of known discontinuity.

Common examination methods include:

- Visual inspection: Performed prior to welding to see that materials are clean, aligned correctly and that welding machine settings, filler selection, etc. are correct for the weldment. As a first stage of inspection of all completed welds, visual inspection under good lighting should be carried out. Undercutting can be detected with the naked eye and (provided there is access to the reverse side) excess penetration can often also be visually detected.
- Liquid penetrant inspection: Performed to check for surface cracking. The method entails cleaning the surface of the weld and the weld vicinity, spraying the surface with a liquid dye that has good penetrating properties, wiping the dye from the surface and spraying the surface with a fluorescent or contrasting coloured powder. Any cracks will have trapped some dye, which will weep out and discolour the coating and will be clearly visible.
- Magnetic particle inspection: Used to detect surface and slightly subsurface cracks in ferromagnetic materials (it therefore cannot be used with austenitic stainless steels). The process involves placing probes on each side of the area to be inspected and passing a high current between them. This produces a magnetic flux at right angles to the flow of the current. An alternative technique uses an electromagnet to produce the magnetic flux

in the part. When these lines of force meet a discontinuity, such as a longitudinal crack, they are diverted and leak through the surface, creating magnetic poles or points of attraction. A magnetic powder dusted onto the surface will cling to the leakage area more than elsewhere, indicating the location of any discontinuities. This process may be carried out wet or dry and use fluorescent or contrasting coloured particles. The wet process is generally more sensitive, as finer particles, which can detect very small defects, may be used.

- X ray inspection: Subsurface cracks and inclusions can be detected via X ray examination. This is expensive, but for safety critical joints, e.g. in submarines and nuclear power plants, 100% X ray examination of welded joints will normally be carried out. Pipe crawler equipment is available for weld inspection (see section 4.5 of Ref. [383]).
- Ultrasonic inspection: Surface and subsurface defects can also be detected by ultrasonic inspection. This involves directing an HF sound beam through the base metal and weld on a predictable path. When the beam strikes a discontinuity, some of it is reflected back. This reflected beam is received, amplified and processed and from the time delay, the location of a flaw is estimated. Results from any ultrasonic inspection require skilled interpretation.

Any detected cracks must be ground out and the area re-welded to give the required profile. The joint must then be inspected again.

7.4. SURVEILLANCE

7.4.1. Plant walkdowns

To enable early detection of a potential plant problem, routine monitoring for leakage should be carried out during normal operation as part of operating staff plant tours. While all reasonably accessible pipework, tanks and related components should be viewed, particular attention should be given to the route of buried pipework and tanks that are identified as high risk. CP system components such as rectifiers should also be included on routine walkdowns, with normal voltages, CP currents and rectifier condition being checked. These walkdowns by the operations staff should be supplemented by a periodic plant walkdown by the system responsible engineer. Refer to Section 7.3.2.6(a) for more details.

The scope of plant system walkdowns should be specified and should be reviewed periodically to take into account OPEX findings or changes in pipe or tank risk ranking.

System engineer walkdowns are undertaken typically on a quarterly basis for high risk buried piping and once every six months for lower risk buried piping. These walkdowns should be more frequent for targeted pipework and during periods when systems are being reconfigured or maintained. Walkdowns should cover the complete system, including the buried route and follow a predefined procedure.

Where maintenance activities coincide with a plant walkdown and permit internal access to plant piping or tanks, the condition of internal surfaces should be inspected for degradation and the results recorded. Where damage to protective coatings is identified, this should be repaired.

7.4.2. Pressures and make-up levels

Changes in pressure or flow readings, decreases in tank levels or increases in tank make-up rates can be indications of leaks. Local monitoring of such parameters as part of a surveillance programme can provide some measure of leak detection. These can be monitored and recorded by operations staff and trended by system engineers.

7.4.3. Tank surveillance

Underground tanks typically have regular surveillance and inspection programmes established. PEI, for example, recommends a system of daily, monthly and annual surveillance for USTs [308]. Daily inspections would focus on leak detection features and the tank fill area (i.e. covers present and containment features intact). Monthly inspections add in interstitial monitoring, groundwater monitoring, checks for the presence of water in the tank,

checks of venting equipment, CP current and voltage checks, checks of proper record keeping and others. Annual testing includes checks for fuel dispenser equipment, pavement around the tank (for settlement), overfill protection checks, tank lining inspections and others.

7.4.4. Settlement monitoring

Settlement monitoring is used for structures that are at risk of or are known to be actively settling. Typical candidates are large civil structures such as the reactor building or cooling towers. The process involves direct or indirect measurements of vertical distances to determine structure elevations. Where structure settlement impacts on connected piping systems, such monitoring is useful to help determine potential levels of piping stress or damage.

An optical or laser device is used to measure the elevations of object points (points to be monitored) and reference points (Fig. 184). When reference points are located within the controlled area only relative displacements can be determined since the reference point may itself have undergone displacement. Absolute displacements can be determined if reference points are located outside that area and are tied to bedrock or another non-moving structure. Although only one reference point is needed in levelling lines, at least three are advisable to help identify any unstable reference points.

Settlement of buried or underground structures may be determined by topographical surveys if object points are available (underground pipe located within a tunnel, buried pipe with manholes, etc.).

Indications of surface soil irregularities (Fig. 74), depressions, or sinkholes also give indications of potential settlement and should be investigated further. Some care must, however, be exerted when considering only surface soil monitoring. Depending on soil layers, subsidence of a layer below the surface grade may occur without or with reduced visual impact on the surface grade (Fig. 185).

7.4.5. On-line monitoring and surveillance

7.4.5.1. On-line monitoring

As described in Section 7.3.3.4(c), installation of permanent GWUT collars can make regular surveillance and trending of at-risk buried piping feasible. Such collars are sealed to protect them from the backfill and soil environment. These permanent collars eliminate the need for digging and backfilling for each inspection, making individual inspections quick and inexpensive. Trending of results can indicate areas of potential metal loss and the need for follow-up direct examination.



FIG. 184. Difference of height determination [394].

Other similar approaches using permanently mounted piezoelectric UT probes are available. Such probes are mounted to outside pipe surfaces by adhesive couplants and attached to communications cables that are routed above ground. Readings can be taken as needed or routed to dataloggers.

GWUT and acoustic emission (AE) technologies also have potential for structural health monitoring of tank floors [395, 396]. AE is also feasible for leak detection in the submerged portions of tanks. Above ground applications of both technologies are currently more feasible. The instrumentation necessary requires access to the buried tank exterior, typically near the bottom, and more research is needed into monitoring solutions due to differences between above and underground tank configurations [297].

7.4.5.2. On-line leak detection

Permanent on-line systems for leak detection in piping runs and around tanks were discussed in Section 7.3.2.6(g).

7.4.5.3. Steel cylinder deformation monitoring

EDF and Oxand have studied the mechanisms for concrete pipe steel core cylinder corrosion due to chloride ions transported by sea water used for cooling. A monitoring technique has been developed using fibre optic sensors that measures circumferential pipe dilatation in operation and correlates the deformation to the residual steel section of the core cylinder [397]. The smaller the residual cross-section is, the bigger the measured deformation by the sensors will be. Figure 186 illustrates the principle. Continuous measurements in operation make it possible to obtain a dynamic view of corrosion evolution in the pipe.



FIG. 185. Surface soil monitoring, subsidence on sublayer soil and limited impact on surface grade.



FIG. 186. Oxand patented cylinder monitoring technique [397].

7.4.5.4. Cathodic protection system monitoring

(a) Background

CP systems should be regularly monitored to ensure they continue to provide adequate protection and to assess potential equipment or coating degradation. Over time, consumption of anodes, changes to plant configuration or changes in geological properties such as soil moisture content can result in inadequate CP. Also, changes in the CP system, such as broken cables or short circuit conditions, can result in decreased current output to the structure, thus reducing system effectiveness. Construction of additional piping systems and/or structures in the vicinity of existing piping systems may interfere with the protective current delivery, thus reducing effectiveness.

Increases in CP current density can be used, for example, to provide an estimate of an external coating condition. Remote monitoring systems for parameters such as CP rectifier current are increasingly available that allow for more timely review of system performance and reduce the burden on maintenance personnel.

Care should be exercised in establishing the location, number and type of electrical measurements used to determine the adequacy of CP. Where practical and determined to be necessary, a CIPS or APEC survey (Sections 7.3.2.3(d) and (g)) should be performed over the piping or area to provide baseline data, assess CP system effectiveness, locate areas of inadequate protection, identify areas likely to be adversely affected by construction, stray currents or other unusual conditions and select areas to be monitored more closely. Three year frequencies are typical; however, longer or shorter intervals may be appropriate. A CIPS should consist of a current interrupted survey using GPS synchronized current interrupters in all affected rectifiers. Depending on the pipeline sections being surveyed and the number of rectifiers installed, a rectifier influence survey may be needed to determine which rectifiers require interruption. The CIPS should include 'on' and polarized 'instant-off' structure-to-soil potentials.

Systems to monitor CP effectiveness can be retrofitted at nuclear power plants. Experienced CP designers (e.g. NACE CP4) are recommended. Exelon, for example, has performed work at its LaSalle nuclear power plant to install smart test stations that can monitor CP effectiveness and corrosion rates in congested areas. The stations are installed via a push probe method and thus do not require substantial excavation and can also provide soil samples (see Fig. 187). The system provides voltage drop readings, material freely corroding coupon potential (i.e. for CS), CP protected coupon potential, freely corroding corrosion rates, CP protected corrosion rates and pipeline of interest potentials.

(b) Cathodic protection criteria

Criteria for assessing CP system performance are included in a number of international standards, including NACE SP0169 [208], ISO 15589-1 [131], EN 12954 [44], AS 2832.1 [228], OCC-1 [398] and GOST 51164 [263]. Some standard criteria are listed in Table 29.

CP criteria in NACE SP0169 are generally consistent with those in OCC-1, while ISO 15589-1 and EN 12954 standards are similar in nature. Neither ISO 15589-1 nor EN 12954 contains a -850 mV on-potential criterion, while both contain additional detailed criteria, including effects of soil resistivity and overprotection. The Russian GOST standard uses slightly different values of soil resistivity and temperatures.

Some differences between the ISO and EN standards are that ISO 15589-1 contains a CP criterion for bacteria effects, while EN 12954 contains CP criteria at different temperature ranges and in anaerobic soil. Overprotection criteria also differ slightly. Additionally, EN 12954 is different from all other standards in that it does not have a 100 mV polarization criterion.

AS 2832.1 is unique in that its -850 mV off-potential criterion is used in conjunction with either a coupon or an electrical resistance (ER) probe and the 100 mV polarization criterion can be used alone or in conjunction with either a coupon or an ER probe. The -850 mV on-potential is recommended for use only when the voltage drops are insignificant, though no specific value for the voltage drop is given. The overprotection criterion in this standard is the same as that in ISO 15589-1 [131, 399]. An explanation of common criteria follows.

(i) 850 on

This criterion is a structure-to-soil potential of -850 mV or more negative with the protective current applied. This is commonly referred to as '850 on' or 'on-potential'. This criterion is normally the only one available for



FIG. 187. Smart Stack cathodic protection effectiveness station installation at LaSalle (courtesy of Exelon).

galvanic systems since the protective current usually cannot be interrupted. Voltage drops other than those across the structure-to-electrolyte boundary must be taken into consideration whenever this criterion is applied. Voltage drops may have a significant impact on potentials observed when testing impressed current systems with the protective current applied. Therefore, the 850 on criterion is not applicable to impressed current systems.

(ii) 850 off

This criterion is a structure-to-soil potential of -850 mV or more negative with protective current temporarily interrupted. This is referred to variously as '850 off', 'polarized potential' or 'instant-off potential'. This criterion is applicable to impressed current and galvanic systems where protective current can be interrupted. Caution must be exercised when testing impressed current systems to ensure that no active sacrificial anodes are installed near the protected structure. If there are active anodes influencing the observed potential, the 850 off criterion is not applicable.

The instant-off potential is generally measured 1 s after the instant power is interrupted (often the second value observed on a digital voltmeter after power is shut off). After 1 s a rapid decay (depolarization) of structure will normally occur. In order to obtain instant-off potentials, a current interrupter or a second person is necessary. If a current interrupter is not available, a second person can be used to throw the power switch at the rectifier off for about 3 s and then back on for 15 s. This procedure is repeated until an accurate instant-off reading has been obtained.

This criterion is considered by most to be the best indicator that adequate CP has been provided. Therefore, consideration should be given to adjusting rectifier output upward until the 850 off criterion has been met if this is feasible.

Standard	NACE SP0169	ISO EN 15589-1	EN 12954	AS 2832.1	OCC-1	GOST 51164
Criteria/environment severity	In standard?	In standard?	In standard?	In standard?	In standard?	In standard?
-850 mV on-potential	X^*			X^*	X^*	
-850 mV off-potential	Х	Х	Х		Х	Х
100 mV polarization	Х	Х		Х	Х	
Soil resistivity < 100 Ω ·cm		Х	Х			
Soil resistivity 100–1000 Ω·cm		Х	Х			
Soil resistivity > 1000 $\Omega \cdot cm$		Х	Х			
Soil resistivity $< 10 \Omega \cdot cm$ or salt concentration $< 1 g/kg$ soil						Х
Soil resistivity > 10 Ω ·cm or salt concentration > 1 g/kg soil						Х
Anaerobic soil		Х	Х			
Pipe temp. $< 40^{\circ}$ C			Х			
Pipe temp. 40–60°C		X***	X**			
Pipe temp. $> 60^{\circ}$ C		X***	Х			
Pipe temp. $< 5^{\circ}C$						Х
Pipe temp. 5–20°C						Х
Pipe temp. $> 20^{\circ}$ C						Х
Bacteria present		Х				Х
Overprotection		Х	Х	Х		Х
Coupon		Х		Х		
ER probe				Х		
Sulphides present						
Acid environment						
Mill-scaled pipe						
Cased pipe						
SCC		Х				

TABLE 29. CATHODIC PROTECTION CRITERIA IN VARIOUS STANDARDS (ADAPTED FROM REFS [263, 399]

* Voltage drop other than that across the structure-to-electrolyte boundary must be considered when it is insignificant.
 ** For temperatures 40–60°C the protection potential may be interpolated.
 *** Standard indicates alternate criteria must be applied for pipelines operating at temperatures > 40°C.

(iii) 100 mV polarization

This criterion is a polarization voltage shift of at least 100 mV, and is commonly referred to as '100 mV polarization' or '100 mV shift'. This criterion is applicable to galvanic and impressed current systems where protective current can be temporarily interrupted. NACE TM0497 [305] can be used for conducting polarization measurements when using this criterion. Either formation or decay of at least 100 mV polarization may be used to evaluate adequate CP. The 'true' polarized potential may take a considerable length of time to effectively form on a structure that has had CP newly applied. If protective current is interrupted on a metallic structure that has been under CP, the polarization will begin to decay nearly instantaneously. For this reason, it is important that protective current not be interrupted for any significant length of time. Generally, not more than 24 hours should be allowed for the 100 mV depolarization to occur. On a well coated structure complete depolarization may take as long as 60–90 days. Complete depolarization of uncoated structures will usually occur within 48 hours although it could take as long as 30 days.

The base reading from which to begin measurement of the voltage shift is the instant-off potential. For example, a structure exhibits an on voltage of -835 mV. The instant-off voltage is -720 mV. In order to meet the 100 mV polarization criteria, structure-to-soil potential must decay to at least -620 mV (final voltage).

Use of native potentials to demonstrate formation of 100 mV polarization is generally only applicable when a system is initially energized or is re-energized after a complete depolarization has occurred. This is because it is necessary to leave the reference electrode undisturbed (or returned to the exact position) between the time when native and final voltages are obtained. It is only necessary to conduct a 100 mV polarization test on that system component where the lowest (most positive) instant-off structure-to-soil potential exists to demonstrate that the system meets this criterion. If the criterion is met at the test point where the potential is most positive, it can be assumed that it will be met at all other test locations.

It should be noted that the 100 mV criterion can be ineffective in determining CP efficacy on steel piping with a high presence of copper in the ground. This can occur at nuclear power plants with extensive ground grids. A small amount of current will naturally exist in steel piping connected to copper grounding, due to the dissimilar metals and the potential difference driving corrosion current.

When different metals are interconnected (e.g. different metals in ground or near Cu ground grids, near building entrances), NACE SP0169 indicates that a negative voltage required for protection of the most anodic metal in the system should be maintained. This can mean that the difference in potential between the anode and cathode sites can be large and 100 mV of polarization may not be enough to ensure the structure is fully polarized. Therefore using the 100 mV polarization criterion should be limited to electrically isolated piping or systems where effects from dissimilar metal couplings, such as CS and copper grounding, are minimal.

(iv) Pipe temperatures

At temperatures > 40°C the criteria listed in Subsections (i) to (iii) may not be sufficient. EN 12954 [44] provides guidance for such conditions. At temperatures greater than 60°C a polarized potential of -950 mV or more negative may be required for adequate CP. The Russian GOST standard [263] identifies temperatures greater than 5°C and 20°C as requiring greater CP potential.

(v) Bacteria and microbiologically influenced corrosion presence

When active MIC has been identified or is probable (caused by acid producing or sulphate reducing bacteria), criteria listed previously in Subsections (i) to (iii) may not be sufficient. EN 12954 [44] provides guidance, for example, for cathodic protection for anaerobic (wet) soil conditions. Under some conditions, a polarized potential of –950 mV or more negative, or as much as 300 mV of polarization, may be required for adequate CP.

(vi) Soil resistivity impacts

As was described in Section 6.3.4, soil resistivity impacts on corrosion rates. EN 12954 [44] does include some impacts of soil resistivity in its table of acceptable protection potentials (Table 1). For example, for CS

(non-alloy Fe material) when moving from aerated sandy soil with resistivity between 100 and 1000 Ω ·cm to that with resistivity of > 1000 Ω ·cm the protection potential changes from -0.75 V to -0.65 V.

ISO 15589-1 [131] specifies these same values of protection potentials for pipelines operating in soils with high resistivity (that is -0.75 V for soil resistivity between 100 and 1000 $\Omega \cdot \text{cm}$ and -0.65 V for resistivity > 1000 $\Omega \cdot \text{cm}$). It also allows as an alternative a minimum of 100 mV of cathodic polarization between the pipeline surface and a reference electrode contacting the electrolyte.

The Russian GOST standard [263] also incorporates soil resistivity into its requirements, with 10 Ω ·cm being a critical value requiring a 100 mV increase in CP and anything over 100 Ω ·cm needing to be dealt with experimentally or by calculation. A calculation of water-soluble salt content is also allowed, with 1 g of salt per kilogram of soil being treated equivalent to the 10 Ω ·cm soil resistivity measurement.

(vii) Overprotection

As was described in Section 4.3.14.5, excessive CP current can damage pipe coatings via a process called cathodic disbondment. The limiting critical instant-off potentials required to prevent damage to coatings differ slightly in published standards, with ISO 15589-1 [131] specifying –1200 mV and EN 12954 [44] specifying –1100 mV. GOST [263] specifies either –1100 mV or –1150 mV depending on temperature, soil resistivity, whether the line is underwater or not and its lining material.

(viii) Material related criteria

Aluminium, copper, stainless steel and PCCP piping should have a minimum of 100 mV of cathodic polarization. Mixed metal arrangements may require additional polarization as described in Subsection (iii), above. To prevent buildup of alkali on aluminium surfaces and prevent corrosion from high pH conditions, excessive voltages exceeding a polarized potential of -1200 mV should be avoided for aluminium.

A polarized potential of -450 mV or more negative in neutral or alkaline soils may be used for stainless steel piping. In acidic conditions, protected potentials should be determined by testing.

Amphoteric materials, such as aluminium and lead, could be damaged by high alkalinity environments created by CP. These metals should be electrically isolated and protected with a separate system where possible.

Polarized potentials more negative than -1000 mV should be avoided for PCCP to prevent hydrogen generation and embrittlement of its prestressing wires. Typically, SACP systems are more commonly used (rather than ICCP) for PCCP. NACE RP0100 [215] provides details.

(c) Trending

Trending of CP currents can be used to detect degradation of protected equipment. For example, using Fig. 188 and knowing the number of years in service, the typical current density can be estimated for the type of coating. A comparison of estimated current density to the actual current density for a segment of pipe coating



FIG. 188. Cathodic protection current density $(\mu A/m^2)$ versus pipeline service time (age in years) of various coatings [400].

can provide an indicator of the amount of degradation. Trending can be done over time to see if degradation is worsening.

Some potential parameters for trending include rectifier operating currents and voltages, anode bed resistance and structure-to-soil potentials. Dates, times, temperatures and weather conditions should be recorded for each set of readings. Once graphed, analysis can be performed regarding CP system performance, anode consumption and changes as a result of seasonal variations or other environmental conditions. Plans can then be made for adjustment of CP voltages, maintenance or replacement of defective or used up components.

7.4.5.5. Groundwater monitoring programmes

Spills and leaks of radioactive material and other contaminants (e.g. fuel oil, solvents, lube oil) from buried piping or other sources can contaminate nuclear power plant on-site groundwater. An effective groundwater management programme is typically required at nuclear power plants to allow for the detection, characterization and assessment of groundwater flows and any potential contamination. Most utilities utilize passive groundwater sampling technologies; however, some research has explored technologies for the real time detection of tritium in groundwater [401]. Such technologies where implemented can help to detect groundwater leakage from buried piping. EPRI [402] and NEI [403] have produced guidelines on plant groundwater monitoring programmes and NEI has additionally issued guidelines on coordination of groundwater and underground piping and tank programmes [404]. The USNRC's Office of Nuclear Regulatory Research has published a scoping study undertaken to identify and assess subsurface monitoring methods for detecting early indicators of leaks at new and existing nuclear power plants, as well as proposed new reactor concepts [405].

7.5. LEAK DETECTION

As discussed in Section 7.4, operations staff and system engineers have a role in leak detection by periodically recording and monitoring water levels within make-up tanks, water meters (where fitted) and pressure gauges (where fitted). Excessive water use or low pressure can be indicative of a leak. Groundwater monitoring programmes described in Section 7.4.5.5 can also be considered a form of leak detection.

Prompt leak detection, source location and repair are important parts of an AMP. Methods for detecting leaks were discussed earlier in Section 7.3.2.6.

The decision to install a dedicated leak detection system depends on leak consequences. Parameters of importance in selecting a leak detection system are:

- Sensitivity: not missing a leak down to a certain threshold;
- Accuracy: correct quantification of leak rate;
- Reliability: preventing false alarms;
- Robustness: design life, operational ease, need for power supplies, resistance to damage, ease of diagnostics and maintenance.

7.6. ASSESSMENT OF PIPING

7.6.1. Ageing management programme requirements

An AMP applies acceptance criteria to results from routine inspections to confirm that the current plant condition is acceptable and, through historical trending of results (plus other data when available), to estimate future performance.

Utilities should document and store all inspection results (direct and indirect) in a controlled database. This documentation should include as-found and as-left data.

Inspection data should be evaluated to determine 'wear rate', 'remaining life', and 'time to next inspection or repair/replacement'.

If inspection results significantly exceed acceptable levels of degradation, underground structure engineers should document the adverse condition and develop appropriate corrective actions, as required. Extent of condition should be considered if there are other locations with similar environments. As part of the corrective action plan, a design disposition exercise should be performed.

When design disposition is involved, the result should determine if the defect is acceptable until the next planned inspection, whether repair or replacement is required.

7.6.2. Time limited ageing analyses

A time limited ageing analysis (TLAA) is an engineering analysis of the suitability of a safety related structure or component that is developed on the basis of an explicitly stated length of plant life. These analyses would typically be done during the original plant design stage, or may be developed at a later date such as being part of a periodic safety review. These need to be revalidated as required as new operating history is obtained, or whenever original design life assumptions need to be revisited, for example in preparation for plant life extensions/long term operation.

Methodologies for such analyses are documented in IAEA Safety Reports Series No. 57 [406]. An example of a TLAA developed as part of the IGALL project (see Section 4.8.7) that can be related to underground piping is TLAA104 Corrosion Allowances.

Callaway nuclear power plant developed a TLAA for its buried ESW piping when it was replaced with HDPE piping. The USNRC staff's evaluation of this TLAA can be found in section 4.7.8 of the safety evaluation report for issuance of the Callaway renewed licence [407]. The principal considerations for the life of replacement piping included operating pressures and operating and accident transient temperatures.

7.6.3. Assessment of functional capability/fitness for service

Once corrosion is detected on a buried pipe, it becomes necessary to assess the integrity of the pipe, its fitness for continued service in the short term and its remaining life in the long term. This section addresses a procedure for integrity assessment of buried piping for wall thinning corrosion. Wall thinning corrosion can take several forms: general thinning, localized thinning, grooving (long narrow wall loss) or pitting. It can be soil side corrosion of the outer diameter, or fluid side corrosion or erosion of the inner diameter.

The evaluation process can be subdivided into steps, which are explained in this section. The evaluation process described here is based on ASME's Boiler and Pressure Vessel Code Section XI, Code Case N-806 [294], entitled Evaluation of Metal Loss in Class 2 and 3 Metallic Piping Buried in a Back-Filled Trench. EPRI has additionally documented a number of methods for FFS evaluation for both safety and non-safety-related metal and concrete pipe systems in Ref. [296]. The Pressurized Water Reactor Operators Group (PWROG) has also published a handbook designed to address the need for a functional capability/fitness for service (FFS) evaluation methodology with the additional goal of providing a means of reducing the amount of time and work required to perform the evaluation. The handbook contains information on evaluation of buried piping FFS techniques [408], structural integrity assessment [409] and various precalculated results for a range of piping materials, sizes, soil classifications and surface loads [410–417]. British standard BS 7910 [418] also provides a guide to methods for assessing the acceptability of flaws in metallic structures.

Evaluation process steps will be addressed one by one in this section and are as follows:

- Step 1: Collection of design data;
- Step 2: Collection of inspection data;
- Step 3: Screening for corrosion;
- Step 4: Pinhole leak assessment;
- Step 5: Level 1 uniform loss assessment;
- Step 6: Level 2 corrosion pattern assessment;
- Step 7: Level 3 finite element analysis;
- Step 8: Run-or-repair decision.

Pipe inspection results are analysed and trended to determine current and future FFS of the system. Assessment should consider the four general damage mechanisms: wall thinning, cracking, embrittlement and mechanical damage.

7.6.3.1. Assessment limitations for buried piping

FFS calculations are more complicated for buried piping than for non-buried piping. Corrosion rates from the soil side and fluid side both need to be combined for the assessment and data related to soil side corrosion under realistic conditions are limited. Underground corrosion in reality is an intricate and time dependent interaction of a number of factors, many of which (e.g. CP, backfill conditions, external coatings) are not a factor for above ground systems. EPRI is developing guidelines for corrosion rates to be used in FFS evaluations of buried piping to complement information contained in ASME Code Case N-806 [294].

FFS techniques normally do not apply to cases of pipe embrittlement or occlusions. In such cases the pipe is normally repaired or cleaned and measures put in place to prevent reoccurrence [296].

Additionally ASME Code Case N-806 does not apply to cast iron piping, leakage through a piping item or piping joint, or a cracked piping item or piping joint. Regarding cast iron, the logic behind the equations for corroded wall thickness (general metal loss (GML) and local thin areas) assumes ductile (plastic) behaviour of the thinned pipe wall, which will not be the case with cast iron.

7.6.3.2. Step 1 — Collection of design data

The following design data should be retrieved or, if unavailable, reconstituted. The data and design calculations are necessary to start with the knowledge of the un-corroded margins which will then be reduced as a result of corrosion. Integrity assessment is not feasible if this starting point, the collection or reconstitution of the design data, is not available.

- (1) Pipe parameters, including: line layout and end points, pipe specifications, material, nominal size, mechanical and physical properties (yield and ultimate strength, modulus of elasticity, coefficient of thermal expansion), allowable stress, types of fittings and their stress intensification factors and stress indices.
- (2) Trench parameters, including: trench profile (ditch, positive projecting conduit, etc.), burial depth, type of bedding below the pipe, trench width and depth, type of fill and compaction, density of dry and water-saturated compacted fill, fill friction angle, modulus of soil reaction, soil springs (bilinear stiffness).
- (3) Ground parameters, including: ground settlement, depth of water table, potential for flooding, site specific seismic data such as peak ground velocities, peak ground accelerations, wave velocities, seismic anchor motions (in the form of potential for landslides, seismic fault movement, liquefaction, fissuring, seismic-induced building settlement, etc.).
- (4) Design loads and load combinations, including: normal operating and design internal pressure (positive and negative), credible static and dynamic (waterhammer) over-pressure, operating temperature (maximum and minimum), post-accident temperature, natural settlement, soil weight (dry and saturated), surface traffic, building bearing pressure, flooding height, seismic wave passage and seismic anchor motion.
- (5) Operating and design loads, including: stress analyses for pressure, soil and surface loads, settlement, flotation, constrained thermal expansion and contraction, seismic wave passage, seismic anchor motions.
- (6) Design margins, including: for un-corroded pipe (nominal diameter and wall thickness), calculated design basis demand-over-capacity (where demand is calculated stresses, strains, loads or deformation and capacity is allowable stresses, strains, loads or deformations) caused by operating and design loads and load combinations listed above.

This first step, the design data and the resulting un-corroded margins, is necessary to proceed with the evaluation of the corroded condition. Where this information is not available or is incomplete, it should be reconstituted. For this task, designers may refer to the following:

[—] Design analysis of buried metallic pipe, Proceedings of the ASME PVP Conference, 2013, Paris, France [419];

- ASME XI Code Case N-806, Evaluation of Metal Loss in Class 2 and 3 Metallic Piping Buried in a Back-Filled Trench [294];
- ASCE, Buried Flexible Steel Pipe: Design and Structural Analysis, Ed. W.R. Whidden, ASCE Manuals and Reports on Engineering Practice No. 119 [291];
- AWWA M9, Concrete Pressure Pipe [34];
- AWWA M11, Steel Water Pipe: A Guide for Design and Installation [222];
- Buried Pipe Design, A. Moser [420];
- Structural Mechanics of Buried Pipes, R.K. Watkins and L.R. Anderson [421];
- WRC Bulletin 425, A Review of Methods for the Analysis of Buried Pressure Piping, G. Antaki [422];
- ASCE Guidelines for the Seismic Design of Oil and Gas Pipeline Systems [423];
- API RP 1102, Recommended Practice Steel Pipelines Crossing Railroads and Highways [288];
- Finite element analysis of buried steel pipelines under strike-slip fault displacements, P. Vazouras, S.A. Karamanos and P. Dakoulas [424];
- US Nuclear Regulatory Commission, NUREG-1800, Standard Review Plan, Section 3.7.3, Seismic Subsystem Analysis [425];
- ASCE 4, Seismic Analysis of Safety-Related Nuclear Structures and Commentary [292];
- American Lifelines Alliance, Guidelines for the Design of Buried Steel Pipe [221];
- AWWA C150/A 21.50-08, American National Standard for Thickness Design of Ductile-Iron Pipe [426];
- Roark's Formulas for Stress and Strain, R.J. Roark, W.C. Young and R.G. Budynas [427];
- RCC-M, Design and Conception Rules for Mechanical Components of PWR Nuclear Islands [48];
- ASCE, Structural Analysis and Design of Nuclear Plant Facilities, ASCE Manuals and Reports on Engineering Practice, No. 58, Section 7.6: Buried pipes and conduits [428];
- ASCE, Seismic Response of Buried Pipes and Structural Components, [429];
- Soil Engineering, M.G. Spangler and R.L. Handy [430];
- US Nuclear Regulatory Commission, Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants, NUREG/CR-6876 BNL-NUREG-74000-2005 [275].

7.6.3.3. Step 2 — Collection of inspection data

Inspection data collected for wall thinning assessment take the form of UT inspection results, most often a grid of measurement points, or a continuous corroded profile scan. The more readings (i.e. the smaller the grid), the better. Using MFL or UT PIGs is ideal if the line is piggable. Short of using a PIG, there is a practical schedule limit as to how many wall thickness points can be measured. A general scan can be first performed using a wheel-mounted UT transducer and then areas that show signs of corrosion can be inspected with a tight grid, for example, with a grid size of twice the nominal thickness, with a minimum of 15 thickness readings (ASME XI Code Case N-806, Appendix A [294]). Figure 189 shows a continuous corrosion profile obtained using a UT PIG and Fig. 190 shows the results of a grid measurement of wall thickness plotted from a spreadsheet.

Measurements are typically recorded in a format that can be transferred to a spreadsheet for Level 2 analysis.

7.6.3.4. Step 3 — Screening for corrosion

This is a simple screening step, in which readings are compared to the thickness tolerance from piping specifications. For example, for an ASTM A 106 CS pipe, factory/mill under-tolerance permitted in ASTM A 106 is 12.5% and therefore readings thicker than 87.5% of nominal wall can be screened out. In other words, there is no evidence of an active corrosion mechanism and these points need not be further assessed. Inspection focus and assessment programme should move to other pipe regions that do not screen out.

7.6.3.5. Step 4 — Pinhole leak assessment

When a pipe does not screen out in Step 3, it must first be checked for its potential for springing a pinhole leak. We know from experience that pinhole leaking is the most common failure mode for buried pipes; therefore this step, which is simple, is essential as it addresses the most probable failure mode.



FIG. 189. Ultrasonic testing pipeline inspection gauge measurement of corrosion pattern.



FIG. 190. Ultrasonic testing grid obtained using point measurements.

Three conditions should be met to prevent a pinhole leak:

$$t_{\rm mm} - FCA \ge 2.5 \text{ mm}$$
$$t_{\rm mm} - FCA \ge 20\% t_{\rm non}$$
$$t_{\rm mm} - FCA \ge \frac{t_{\rm min}}{2}$$

where

 $t_{\rm mm}$ is minimum measured wall thickness (lowest reading in mm of all points); FCA is future corrosion allowance (wall loss in mm until next inspection or end of life);

- t_{nom} is nominal wall thickness of uncorroded pipe (mm);
- t_{\min} is minimum wall thickness required by design code, for internal pressure (mm).

These three conditions are consistent with ASME FFS-1/API 579 "Fitness-for-Service" [283], Part 4: General Metal Loss, and the first two are consistent with ASME XI Code Case N-806 [294].

- The first limit (2.5 mm) is arbitrary but logical: it reflects that where there is an active corrosion or erosion wall thinning mechanism, a pipe that has been thinned down to 2.5 mm is near the point where it will leak, taking also into account the accuracy of thickness readings.
- The second limit (20% t_{nom}) is also arbitrary but logical: it reflects that where there is a corrosion mechanism that has already consumed 80% of the wall it is time to take corrective action before returning the line into service. ASME XI Code Case N-806 permits an exception to this 20% t_{nom} condition, if the area reinforcement rule of the design code is met.
- The third condition (50% t_{min}) permits the internal pressure design margin of the original design code (a margin of over 3 for ASME III and B31.1) to be reduced by half at the single worst spot.

These three conditions address pinhole leak protection and the additional following steps are necessary to address the other forms of rupture: burst and fatigue.

7.6.3.6. Step 5 — Level 1 uniform loss assessment

This is the most straightforward, but most conservative assessment approach. The corroded pipe is assumed to be corroded uniformly down to t_{mm} . For example, if the single worst reading in a 9 mm nominal wall pipe is down to 6 mm, the whole pipe is assumed to be corroded down to 6 mm. All the design equations retrieved in Step 1 are then rechecked using a uniform wall thickness of t_{mm} — FCA and are compared to the design code allowable stresses, strains, loads and deformations.

7.6.3.7. Step 6 — Level 2 corrosion pattern assessment

If the conservative approach of Step 5 does not qualify, then a Level 2 approach is necessary. In this approach, the actual corrosion pattern is taken into consideration and three general categories of criteria are checked: (a) burst due to internal pressure, (b) collapse of the round pipe cross-section acting as a ring confined by the surrounding soil and (c) longitudinal and shear stress limits for the pipe acting as a beam confined by the surrounding soil.

- (a) First, assess the burst potential of the pipe with the measured corrosion profile minus the future corrosion allowance FCA. Within this Level 2 burst check there are two sublevels of assessment:
 - (i) Sublevel a: The GML technique that follows the assessment method of ASME FFS-1/API 579 [283] and which is addressed in ASME CC N-806 [294], Section 6.1.1.
 - (ii) Sublevel b: If the GML approach does not qualify, then a more refined method can be applied (local metal loss method), which depends on the type of corrosion pattern:
 - Narrow groove corrosion (CC N-806 Sections 6.1.2(c)(1) and 6.1.2.1);
 - Limited area corrosion (CC N-806 Sections 6.1.2(c)(2) and 6.1.2.2);
 - Unlimited area corrosion (CC N-806 Sections 6.1.2(c)(3) and 6.1.2.3);
 - Bend corrosion (CC N-806 Sections 6.1.2(c)(4) and 6.1.2.4).
- (b) Second, assess pipe stability acting as a confined ring. This assessment consists of checking pipe ovality corroded down to the measured pattern minus the FCA and checking crushing of the two sides of the pipe (3 o'clock and 9 o'clock locations) and external hydrostatic pressure in case of flooding.
- (c) Third, assess behaviour of the corroded pipe as a beam by checking longitudinal and shear stresses caused by settlement, constrained expansion or contraction, seismic wave passage and anchor motion. Also, check potential for flotation in case of flooding or rise in the water table.

Level 2 analysis, however, requires a good knowledge of the corrosion pattern. Some guidance can be found in ASME Code Case N-806 [294].

7.6.3.8. Step 7 — Level 3 finite element analysis

If Step 6 does not qualify, the plant can decide to proceed to Step 8 and repair, or perform a Level 3 finite element analysis (FEA). In this case a finite element model of the corroded pipe (current measured wall thickness minus FCA) and the soil model are developed and benchmarked. The loads are then applied to the model and the limits on ovality, stresses, strains, loads and deformation are evaluated.

7.6.3.9. Step 8 — Run-or-repair decision

Having completed the screening process, the pinhole leak check and the Level 1 and Level 2 assessments and in some cases the Level 3 FEA assessment, the plant can decide to continue to operate or repair the corroded pipe sections. If continued operation is feasible, the remaining life is calculated based on FCA (mm) divided by the corrosion rate (mm/year). The corrosion rate, unless clearly established or arrested, may include a safety factor of 1.5.

Further details on calculating corrosion rates can be found in a number of sources, including the NACE corrosion survey database [431], EPRI Report 1025256 [432] and Ref. [226].

7.6.3.10. Evaluation for cracking

So far, the integrity assessment was based on wall thinning mechanisms (corrosion or erosion). If the damage identified during inspections is in the form of cracks, it could be due to (a) weld fabrication flaws that may or may not have grown in service, (b) corrosion cracking, (c) fatigue, or a combination of all three. There are no methods specifically developed for the assessment of cracks in buried pipes, but there are well established techniques for FFS of crack-like flaws in standards such as ASME XI [294] and ASME FFS-1/API 579 [283] that can be adapted to evaluate the unique loads of buried pipes.

7.6.3.11. Evaluation of embrittlement

In certain cases old buried pipes may embrittle by leaching, this is the case, for example, for graphite leaching of cast iron and dezincification of brass alloys. In these cases, there is little that can be done to calculate a remaining life and the pipe should be replaced.

7.6.3.12. Evaluation of mechanical damage

Mechanical damage in the form of dents (distortions of the cross-section, typically caused by third-party damage) and gouges (sharp surface cuts) is a well-known and well-studied concern for high pressure oil and gas pipelines, which operate at high hoop stress. This type of damage is typically a lesser issue in service water and gas service systems which operate at low hoop stress, typically below 20% of the material yield stress. Methods for the FFS evaluation of dents and gouges can be found in ASME FFS-1/API 579 [283].

7.6.3.13. Concrete pipe assessment

EPRI has documented a number of methods for FFS for concrete pipe systems [12]. Concrete pipe failure modes are different from those of metal pipe and depend on both the concrete core and its steel cylinder and/or reinforcement (prestressing wires or bar). FFS evaluations typically involve assessment of the extent of degradation (e.g. numbers of wires or bars broken) for a given pipe pressure against a risk curve that yields a relative repair priority. Figure 191 shows an example of such a risk curve for a PCCP pipe. The various regions of the chart correspond to different risk priorities for repair action; for example, repair priority 2 might require repair within five years, while repair priority 1 might require immediate action.

Predictive modelling of concrete pipe degradation due to corrosion has been used in Europe to determine the expected life of a pipe as a basis for a regular replacement strategy [434]. The models are based on the time required for chlorides from sea water to permeate the inner mortar lining and corrode the steel cylinder. Predictive modelling



FIG. 191. Risk curve developed for 121.2 cm (48 in) steel lined cylinder prestressed concrete cylinder pipe with broken steel wires and corroded steel cylinder [433].

of pipe degradation due to aggressive external environments is significantly more difficult and unpredictable due to the variability of the external environment.

7.6.3.14. Non-metallic pipe assessment

Formal FFS criteria for non-metallic pipe such as HDPE have not yet been developed; however, the material has a good track record in service.

7.6.3.15. Tank assessment

API 653 [285] provides guidelines for acceptance criteria for roofs, shells, bottoms and foundations for above ground storage tanks. STI SP001 [311] provides criteria for continued service based on tank category for damage or harm.

7.7. RECORD KEEPING

These data support the evaluation of current condition as well as estimates of future performance.

Records of any inspections undertaken should be kept and maintained. The records must enable the reliable and accurate identification of the plant item being inspected. They should include:

- Level and extent of inspection undertaken, including inspection procedure;
- Outcome of any inspections and any remedial work conducted.

Inspection data should be evaluated to determine 'wear rate', 'remaining life' and 'time to next inspection or repair/replacement'.

Practical guidelines on implementation of an effective system for data collection and record keeping for ageing management purposes were first provided in IAEA Safety Series No. 50-P-3 [314].¹¹ Information on plant configuration management IT systems is found in Ref. [435].

Records should be readily retrievable and contribute to a repair/replacement strategy. They should be regarded as permanent records and should be stored appropriately for the life of the station. When defects are detected, their

¹¹ This publication is no longer considered an up to date IAEA Safety Standard.

location, size and orientation should be reported, photographed or videoed, if practicable, and recorded. Where it is judged that defects could pose a potential risk to plant integrity, appropriate additional inspections should be carried out and repairs/replacements undertaken as required. Results of these additional inspections, assessments and repairs/replacements should be recorded. Furthermore, these locations should be considered under an ongoing inspection regime to identify whether further degradation or damage is taking place.

Once a defect has been found, the implications of the discovery on other system components should be assessed to determine whether similar components/locations/systems should also be inspected. OPEX should be recorded and shared with stations having similar equipment.

8. MAINTENANCE AND REPAIR OF AGEING EFFECTS

A plant's maintenance organization has a key role to play in a buried and underground piping and tank programme. The organization implements ageing management by conducting day to day maintenance and repair activities, observing plant equipment at a detailed level and recommending improvements. Improper maintenance or parts substitutions can increase the chance of piping degradation. For example, increasing CP system rectifier output could cause an increase in potential for stray currents to be generated that may have a detrimental effect on other buried metallic structures in the vicinity. Excessive rectifier output can also significantly shorten anode ground bed life, since anodes will be consumed more quickly than necessary.

Maintenance strategies for a component can be either run-to-failure, preventive, or corrective. Each of these and their implications for a buried piping and tank programme are discussed below.

8.1. PREVENTIVE MAINTENANCE

Depending on the material, preventive and mitigative techniques for underground piping and tanks may include changing the material itself, external coatings for external corrosion control, application of CP and changing the quality of backfill utilized. Also, depending on the material, inspection activities may include electrochemical verification of the effectiveness of CP, NDE of pipe or tank wall thicknesses, hydrostatic testing of the pipe and visual inspections of the pipe or tank from the exterior as permitted by opportunistic or directed excavations.

In addition to the immediate repair for underground piping and tank integrity, if the risk of failure is unacceptably high, it is recommended that measures be taken to mitigate the conditions causing the degradation and prevent failures and their consequences from recurring (Fig. 192). Consequently, where risk of failure is



FIG. 192. Prevention and mitigation (implemented).

unacceptable, preventive and mitigative options should be implemented. In practice it may not be very easy to distinguish between unacceptable and acceptable risks of failure, with the choice of approaches in reality taking into account a wide range of factors such as the cost and ease of preventive measures when compared to mitigation.

Preventive maintenance may be seen as a proactive intervention where some form of activity is applied prior to damage becoming visible. Proactive condition control is well suited for nuclear facilities since it is important to keep performance above a certain safety function and to minimize lifetime costs.

Various strategies are available for preventive maintenance. Preventive maintenance should include periodic, predictive and planned activities (see IAEA Safety Standards Series No. NS-G-2.6 [436]).

Periodic maintenance includes servicing, parts replacement, surveillance or testing at predetermined time intervals, operating cycles or operating times. For underground piping and tanks, parts replacement is often not an option. Measures to prevent fluid side and soil side degradation include pipe replacement by a resistant material.

Predictive maintenance is a form of preventive maintenance performed continuously or at regular intervals as governed by observed conditions (i.e. condition based maintenance). The results of such activities may generate required planned maintenance activities. Planned maintenance is refurbishment or replacement of a system, structure or component that is scheduled prior to its unacceptable degradation.

Some methods of preventive maintenance related to underground piping and tanks include CP, soil and water analysis, cleaning the inside of the pipe, leak detection and attention to surface coatings and linings. Measures to prevent fluid side (ID) degradation include water treatment, cleaning and lining.

The line between preventive and corrective maintenance is not precise. For example, pipe replacement of a degraded area from a buried pipe's surface can be a preventive or corrective action. The replacement both corrects the observed condition and restores original wall thickness and design life for the replaced section.

8.1.1. Condition based strategies

In nuclear facilities, a condition based strategy for underground piping and tanks may involve monitoring the number and magnitude of load or action cycles applied, comparison to design values, system response and consideration of corrective actions. Such actions can include water treatment and system operation modifications to reduce corrosion susceptibility in plant operation (refer to Sections 6.1 and 6.2 for considerations surrounding system operation modifications and chemistry control). Measures to reduce the risk of failure include reducing hydraulic transient pressures and eliminating potential sources of water hammer and cavitation. For underground piping, additional measures to reduce the risk of failure include the restoration of design margins to trench, tunnel and vault structures that contain the pipe.

For coatings, a condition based action could be the replacement of surface coating layers due to wear, in which case the exceeding of an allowed wear value (coating holiday) invokes the action of preventive maintenance.

8.1.2. Time based strategies

Possible time based preventive actions include periodic CP system maintenance (rectifiers, anodes, etc.), periodic flushing and cleaning, and regular coating maintenance or reapplication.

8.1.2.1. Cathodic protection system monitoring and maintenance

Subsequent to system commissioning, periodic inspection and maintenance of CP systems should be performed. The goal is to ensure that protection is being achieved and the system is operating reliably, and to diagnose problems.

Procedures used should be regularly reviewed to reflect new OPEX, system additions and/or new technology. System records should be maintained and data should be trended to observe changes in current delivery, operating voltage, anode bed resistance and structure-to-soil potentials. Remote monitoring of rectifier DC output may be used. Manual records may be acceptable for some systems, but for larger volumes of data, computer based systems are preferred.

CP system maintenance includes scheduled maintenance, periodic inspection and replacement and/ or adjustment of the system components. Unscheduled maintenance may include troubleshooting and repair of defective items and components. All rectifiers operating ICCP systems should be checked at intervals not exceeding two months. Longer or shorter intervals may be appropriate. Evidence of proper functioning may include measurement of the rectifier DC output voltage and current or measurement of the structure-to-soil potential at test stations using portable and/or permanently installed reference electrodes.

ICCP systems should be inspected annually as part of a preventive maintenance programme to minimize in-service failures. Longer or shorter intervals may be appropriate. Rectifier inspections may include a check for electrical malfunctions, safety ground connections, meter accuracy, efficiency and circuit resistance. Annual inspections should include measurement of polarized (instant-off) structure-to-soil potentials at test stations and other monitoring sites using portable and/or permanently installed reference electrodes, anode currents at junction boxes and rectifier DC output voltage and current readings.

SACP systems should be inspected annually as part of a preventive maintenance programme to minimize in-service failures. Longer or shorter intervals may be appropriate. Where appropriate, inspections should include measurement of structure-to-soil potentials at test stations, measurement of sacrificial anode current and verification that isolation joints and DC decoupling devices are effective. Table 30 provides a list of the parameters to be monitored and the typical frequency. Frequencies referred to are derived from NACE SP0169 [208].

TABLE 30. CATHODIC PROTECTION MONITORING PARAMETERS

CP parameter	Typical frequency
Rectifier/power source output (volts/amps, normal power consumption)	Every two months
Anode bed resistance (calculated)	Every two months (if significant changes, individual anode outputs should be adjusted)
Rectifier inspections (electrical malfunctions, safety ground connections, meter accuracy, efficiency and circuit resistance)	Annual
Structure-to-soil potential survey (polarized, instant-off)	Annual
CIPS (include structure-to-soil potential)	As needed — longer or shorter (three years for critical piping systems)
Interference survey (stray currents or other unusual environmental conditions)	Annual
Bond currents and isolation checks (that would jeopardize protection)	Every two months (otherwise annual)

Bonds are metallic connections between piping systems that are not inherently electrically continuous but are intended to be cathodically protected together. Electrical isolation provides electrical segregation between piping systems that are electrically continuous but are not intended to be cathodically protected together. If the failure of the bond or electrical isolation would jeopardize CP, then the bond and isolation should be checked bimonthly. To determine whether the bond or isolation is critical, remove the bond or electrically short the isolation and resurvey the piping to assess protection levels. If the structure protection remains adequate, then the bond or isolation is deemed non-critical and checks should be performed annually.

Common problems with SACP systems are shorts or failure of dielectrics on isolated protected structures. Sacrificial anodes have a limited ability to supply current due to their limited voltage. When a protected isolated structure is shorted to another structure, the protective current demanded by the combination may be more than existing anodes can supply. For SACP systems, maintaining the electrical isolation of structures (insulating joints) is essential to long term system performance. Well coated structures maintain high soil contact resistance and as a result, require very low current. Metals that are not well coated and have low soil contact resistance require more protective current and deplete anodes more quickly.

CP systems are static. If they stop working, failures may not be noticed unless routine surveillance notes a potential problem or until the protected structure fails. Periodic surveys are essential to detect CP system problems so corrective actions are taken before a structure is damaged.

ICCP systems have more components than SACP systems. These components can and do fail. The major components in an ICCP system are the rectifier, anode bed, structure lead, anode lead (header cable) and structure. Major components in a SACP system are the anode, test station and structure lead. If a routine CP survey determines that adequate CP does not exist on a protected structure, then troubleshooting must be performed to determine the cause of this lack of protection.

Troubleshooting SACP systems is a matter of determining if the sacrificial anode has been consumed or a lead wire connecting the anode to the structure has been broken. The starting point of the troubleshooting is with the anode (or anode connection). The sacrificial anodes are consumed at a relatively constant rate. As a result, anode failure can be predicted by the current measurement versus time when trended.

Troubleshooting ICCP systems may be required if protective levels (measured structure-to-soil potentials) have dropped or if there is an abrupt change in rectifier DC output readings. Either of these changes should initiate troubleshooting to determine the cause of the problem.

Generally, low or zero output is most often caused by power supply failure to the rectifier or rectifier failure. Output that tails off steadily over time indicates anode bed issues. High current output may indicate a short circuit or a reduction in electrolyte resistivity. Whenever there are sudden or substantial changes to rectifier output, further investigation is required to determine the cause of the change.

The first step in troubleshooting and repairing a system is to determine which component has failed. Troubleshooting an ICCP system starts at the rectifier. Often the problem can be spotted at this location by physical observation and then verified by additional testing. To start troubleshooting a rectifier one should study the circuit diagram furnished with the manufacturer's operation and maintenance manual. If there is no circuit diagram, it is usually worthwhile to trace the circuit and develop a diagram.

8.1.2.2. Cleaning and flushing

Raw water systems are most likely to have issues related to occlusion of their inner diameters. These may include safety and non-safety service water systems, fire protection systems, circulating water systems and various treated water systems (typically using high purity water that has had corrosion inhibitors, biocides, etc. added to it). High purity water (e.g. condensate) systems are not likely to require ID cleaning. Cleaning of other systems such as fuel oil, lube oil, radioactive waste and gas systems, if required at all, will be via highly specialized procedures.

Cleaning can be used to restore desired flow capability and operating margins, remove biofilms and corrosion products that can be sites of future degradation, or to prepare surfaces for recoating. Cleaning also permits future chemical cleaning treatments (discussed below) or regular chemistry control (Section 6.2) to work more effectively, reduces their cost (lowers the amount of chemicals needed) and allows for lower effluents.

Cleaning methods include both mechanical and chemical means. Advantages and methods of pipe cleaning are provided in Table 31. Mechanical methods include water flushing, air scouring (flushing using air injected into the fluid to increase turbulence), using water or air jets, or using abrasive particles ('blast cleaning') [12].

Mechanical cleaning PIGs (Fig. 193) are available in a variety of sizes and levels of aggressiveness. Like inspection PIGs (Section 7.3.3.11), cleaning PIGs require launch and retrieval stations and taking the pipe out of service. Following pigging, pipes are usually checked for cleanliness with a borescope. Mechanical PIG cleaning is almost always done with propulsion by air or nitrogen. Use of PIGs can be limited by pipe diameter and number of bends and tees in a line.

Chemical cleaning involves circulating an inhibited acid or chelating agent in the piping system to dissolve scale, biological growth and corrosion products. The chemicals used can be costly and dangerous to handle, and the processes can generate large quantities of liquid waste that need to be managed and disposed of. Such processes need tight control and qualification to ensure that the systems treated are not adversely impacted.

Dirt, grease and sediment can also accumulate in piping system components such as ARVs. To avoid malfunctions ARVs must be checked and maintained, if necessary, at regular intervals. Typical maintenance consists of cleaning valve bodies, seats and seals, and performing flushing.

The AWWA has produced a manual, M28 [437], on the cleaning and lining of water mains.

TABLE 31. ADVANTAGES AND METHODS OF PIPE CLEANING/FLUSHING (ADAPTED FROM TABLE 12-1 FROM REF. [12])

Physical process	Primary benefits	Recommended methods	
Replacement of poor quality water	Removes bacteria/contamination Raises disinfectant residuals by drawing in fresh water Minimizes risk of nitrates and nitrites resulting from nitrification Reduces risk of colour and appearance degradation (removes suspended materials)	Conventional flushing Unidirectional flushing	
Removal of sediment deposits	Improves hydraulic efficiency Improves disinfectant penetration (impedes growth of biofilms)	Unidirectional flushing Air scouring Soft swab pigging	
Removal of tuberculation, scale or other deposits		Poly pigging Chemical cleaning Jetting Mechanical drag/scraping	
Pipeline rehabilitation	Improves colour and appearance Impedes growth of biofilms Reduces risk of coliform regrowth Reduces disinfectant demand Improves hydraulic efficiency Extends life	Mechanical or other cleaning, followed by: Cement mortar lining Epoxy lining Structural lining	



FIG. 193. Mechanical cleaning pipe inspection gauges exiting pipework (left: courtesy of Vecom Group Inc.; right: courtesy of Russell NDE Systems Inc.).

8.1.2.3. Application of coatings

See Section 4.10.2 for information regarding the selection and application of coatings. Field repair coatings include a variety of materials such as coal tar over the ditch, hot applied coal tar tape, cold applied tape, viscoelastic tape, liquid epoxy, liquid polyurethane and moisture cure urethane. Some advantages and disadvantages of each are shown in Table 32.

8.2. CORRECTIVE MAINTENANCE

The replacement or repair decision following an inspection should be determined based on projected and needed design life. An FFS assessment will indicate whether the defect (wall thinning, cracking, mechanical

damage, occlusions, prestressing wire breakage, joint opening, lining and coating degradation, etc.) is acceptable until the next inspection, or whether a repair or replacement is necessary and when it should be implemented.

TABLE 32.	COMPARISON	OF SOME	COMMON REPAIR	COATINGS
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Material	Advantages	Disadvantages
Coal tar	Low cost Easy to apply	Low soil stress resistance Difficult to maintain application temperature Uneven flow can result in uneven/ inadequate coating, particularly at 4 o'clock and 8 o'clock positions Susceptible to SCC Health and safety concerns
Hot applied coal tar tape	No heating Easy to apply with wrapping machine High productivity Uniform thickness Less dependence on human skills	Low adhesion and susceptible to delamination Susceptible to SCC Cathodic shielding Tenting effect observed on saw pipes
Cold applied tapes	Low cost	Low adhesion and susceptible to delamination Susceptible to SCC Heating during application poses risk to pipeline and human life Cathodic shielding Tenting at weld seams Lumping and thinning Holidays, wrinkles, etc. Difficult to apply Low progress
Viscoelastic self-healing coating	Permanent solution Impregnates steel No adhesion issues Cold applied No cracks Simple, fast and easy to apply One component material Minimal surface preparation Tensionless application No special tools required Remains flexible forever Easy to mould No waste/non-toxic No shelf life limits	No soil stress resistance so can wrinkle in certain soils Removal difficult
Liquid epoxy	Good adhesion and cathodic disbondment resistance Good soil resistance Good performance in wet conditions No known SCC instances Fast application, not very dependent on human skill No tenting on saw pipes; good bonding on intricate surfaces	Longer cure time compared to urethane; slow cure below 5°C Requires insect and dust control until cured Requires PPE during application and inspection Less surface imperfection tolerant

Material	Advantages	Disadvantages		
Liquid polyurethane	Good adhesion and cathodic disbondment resistance Good soil resistance Fast curing and low temperature curing possible No known SCC instances Higher impact resistance than liquid epoxy Adequate mechanical strength to absorb shock, handling, abrasion Fast application, not very dependent on human skill Does not shrink, thus good for field joints and on weld seams UV resistant Fast return to service (dries quickly) Very difficult to remove	Less resistance to cathodic disbondment than liquid epoxy Requires insect and dust control until cured Requires PPE during application and inspection Less surface imperfection tolerant Low pot life Limited applications present in industry Very difficult to apply by brush (spray skid required)		
Moisture cure urethane	Long term adhesion Fast curing Easy to use (one component, no recoat window) Can be applied in all weather (cures at -15°C, can be applied to damp substrates, etc.) Surface tolerant			

TABLE 32.	COMPARISON OF SOME COMMON REPAIR COATINGS ((cont.)	

8.2.1. Repair guidelines and techniques

Pipeline repairs are typically localized in nature (e.g. pad welding, clamps) or over segments (e.g. several metres of piping) within a given zone. Complete replacement of entire underground structures (pipes and components) is discussed in Section 8.4.

Repairs should be assigned a design life rather than simply labelling them 'temporary' or 'permanent'. Reinspection or replacement of a repair should be determined and documented based on the projected and required design life of the repaired system.

This section discusses considerations related to locating and excavation piping for repair, general repair techniques and some specific techniques related to specific types of pipe or tank.

8.2.1.1. Locating buried piping

Knowledge of location, depth and burial conditions of all buried components is essential for maintenance and repair activities. This allows for efficient location of components, safe and efficient work and excavation planning (see Section 8.2.1.2) and evaluation of CP systems [12]. All underground services are of interest, including piping, tanks, electrical conduit and cables, telephone lines, ground grids, drainage systems, CP system components and abandoned equipment. Increasingly, 3-D models (see Fig. 194 for an example) of these underground services are being developed by operating organizations.

Plant data are a useful initial source for locating underground structures. Typical data include plant construction drawings, piping isometrics, construction photographs, work orders (maintenance history) and piping and instrumentation drawings. Construction drawings are probably the largest source of information regarding the location, depth and burial condition of buried and underground piping and tanks. Some specific records to be reviewed are:



FIG. 194. 3-D model of underground buried pipe at Qinshan nuclear power plant [438].

- System descriptions to identify system functions, lines, start and end points;
- Leak logs, records of past digs, inspections and repairs;
- Piping line lists to identify design and operating pressure and temperature and pipe material, etc.;
- AMP (can confirm route of piping included in programme);
- System operation records, including past transients and water treatment;
- Past CP and coating surveys;
- Any documented instances of ground or building settlement.

Discussions with maintenance, operations and engineering staff, especially personnel who were on site when the plant was built or when major inspections and repairs were made, are also of use to fully understand plant history.

GPR, conductive tracing, inductive tracing and acoustic tracing are available to locate buried structures for the purposes of excavation and validation of construction information or for validation or creation of updated drawings of pipe routings. Each of the methods of locating buried structures is discussed below.

Following any excavation (or for new installations) marker products such as those shown in Fig. 195 can be installed to facilitate future service location. Such markers are typically installed a minimum of 1 m deep and can be programmed with details, including type of service, depth, date of placement, permit number and map coordinates.

(a) Ground penetrating radar

GPR is a technology used extensively in geology, archaeology, forensics and construction to gather subterranean information quickly and inexpensively. GPR uses electromagnetic radar pulses to image the subsurface. GPR can also be used to investigate the internals of concrete structures, including concrete pipe. In such applications it can detect the position of rebar, other embedments or voids. Equipment can be moved easily, making thousands of measurements in an area. A computer puts these together to make a 3-D model of buried or embedded objects.

A GPR probe emits pulses of electromagnetic energy in the microwave band (UHF/VHF) of the radio spectrum and detects reflected signals from subsurface structures. A computer processes the reflected signal and produces a visual representation of the subsurface.



FIG. 195. Buried service line marking and location equipment at Lawrence Livermore Lab (courtesy of Underground Construction magazine; used by permission) [439].

An illustration of the technique is shown in Fig. 196. While the GPR unit is moved along the surface, reflections are achieved from underground structures, in this case a geological boundary and pipe. Pipe reflections form a hyperbolic signature in the diagram. The bottom left portion of the figure shows how objects can be detected at a controlled test site. Both metallic and non-conducting materials such as polystyrene, concrete and wood can be clearly indicated.

GPR uses either transmitting and receiving antennas or only one containing both functions. The transmitting antenna radiates short pulses of the HF radio waves into the ground or structure. When the wave hits an object or a boundary with different dielectric constants, the receiving antenna will record variations in the reflected return signal.

The depth range of GPR is limited by electrical conductivity, transmitted centre frequency and radiated power. As conductivity increases the penetration depth decreases. This is because electromagnetic energy is more quickly dissipated into heat, causing a loss in signal strength at depth. For dry, sandy soils penetration depth can be to 10 m, while for clay, moist or salty soils penetration depth can be less than 30 cm.

Higher frequencies do not penetrate as far as lower frequencies, but give better resolution. Good penetration is also achieved in dry sandy soils or massive dry materials such as granite, limestone and concrete where depth of penetration can be up to 15 m.

Individual lines of GPR data represent a subsurface sectional (profile) view. Multiple lines of data systematically collected over an area may be used to construct three dimensional images.

In recent years, multichannel (8–32 channels) GPR solutions have become increasingly available. The simpler one-channel solutions (as described above and shown in Fig. 196) are now mainly used to avoid pre-excavation utility. That is, when an excavation is ready to start a GPR user can quickly scan over an area to help avoiding digging into existing utilities. For avoidance, only a minimum of (real time) processing is made and interpretations are done on the spot. For utility mapping, which are (usually) larger scale surveys where the aim is to map out all existing utilities in a given area, the newer multichannel GPR solutions would normally be used. These multichannel solutions are much more efficient and accurate, and provide much more detailed results. Figure 197 shows some typical equipment and results.

(b) Conductive and inductive tracing (AC current)

Tracing equipment is often referred to as pipe locating equipment because it is commonly used to locate pipe. Conductive tracing uses AC current directly applied to an underground structure that is to be located using a transmitter (Fig. 198), whereas inductive tracing does not require a structure connection and instead induces a signal on the pipe.


FIG. 196. (Left) Ground penetrating radar examination technique; (right) single channel equipment (courtesy of Malå Geoscience) [440].

Conductive methods are more accurate than inductive because their direct pipe connection isolates signals to that pipe. Grounding of both transmitter and pipe is critical to accurate locating, as signals will be weak if not well grounded. The inductive method is easier to use as the transmitter can be set on the ground directly above the pipe.

In both methods, current will attenuate (Fig. 199) as the operator goes away from the transmitter. Attenuation is a function of soil conductivity, pipe diameter, coating quality and signal frequency.

The equipment allows the operator to change signal frequency to optimize the survey. The choice of signal frequency is an important factor for effective tracing and identification of buried lines and there is no single frequency that covers all conditions for location of services. Active signals between 8 kHz and 33 kHz are commonly used. Typically, ranges are:

- Low (< 1 kHz): These frequencies provide most accurate results in congested areas. They are used for tracing over long distances and do not couple easily to other below grade conductors. They are too low for induction and fall within the band of power frequency harmonic interference.</p>
- Medium (1–10 kHz): This range of frequencies is the most general-purpose. They will couple to other conductors but not as easily as high frequencies. They can be used for short distances of 0.6 km or less and are best used when inductive methods are required. The range is outside the power frequency interference band but may not be high enough to impose a strong signal on small diameter lines such as telecom cables.



FIG. 197. Multichannel ground penetrating radar: (top left) typical equipment; (top right) site to be mapped; (bottom left) array data slice; (bottom right) array interpretation (courtesy of Malå Geoscience) [440].



FIG. 198. Conductive tracing transmitter connection.



FIG. 199. Inductive tracing fundamentals, transmitter/receiver and receiver display (courtesy of and copyright 2014 Radiodetection Ltd.; all rights reserved).

- High (10 kHz–100 kHz): These frequencies are typically used to trace small conductors and will couple strongly to other nearby conductors. They work best with inductive tracing and are very useful for initial searches;
- Very high (> 100 kHz): These frequencies attenuate quickly and are useful for short runs of pipe or with difficult cases such as small diameter lines in dry sandy soil. They work best with inductive methods where the operator would want to sweep an area quickly for all below grade conductors.

Signals will be induced on any conductor within transmitter range, therefore induction is not recommended in congested areas. High frequencies should be used with the inductive method. Grounding grids and other conductive structures within a plant can make it difficult to accurately locate buried piping. Pipes directly connected to grounding grids may be difficult to locate.

Non-metallic pipe can be located by inducing the signal on a metal fish tape, snake or heavy gauge wire that can be inserted into the pipe. In some installations metal tracer wires are installed that run the length of the installed pipe to facilitate its future location. A signal transmitter known as a sonde can also be inserted into the line to create the required signal.

The PCM tool described in Section 7.3.2.4(b) is another example of a tool using this principle.

(c) Acoustic tracing

Acoustic tracing uses an acoustic transmitter inside the pipe. This tracer emits a unique signal that is transmitted through the fluid and detected by an external above ground receiver. The method's benefit is that it can be used to locate all types of pipe materials: metallic, non-metallic, concrete and plastic. This method locates pipe leaks better than it does pipes without leaks because the acoustic signal is stronger when a leak is present. See Section 7.3.2.6(a) for further details on acoustic leak searches.

8.2.1.2. Excavation of buried structures

Excavation activities can be hazardous for both the personnel and equipment involved. Trench failures can trap and suffocate personnel, digging can risk untended contact with and injury from undocumented power or gas lines, and pipes or other equipment contacted can fail unintentionally or have its safety-related functions, such as seismic robustness, compromised.

Nuclear facilities need a good trenching and digging industrial safety programme to address known and unknown hazards from such activities. Parts of such a programme can include (adapted from Ref. [296]):

 Clear identification of areas to be excavated (e.g. 'white lining' processes whereby lines can be made with paint on hard surfaces, or lime or paint on ground surfaces).

- Underground service location and documentation (using GPR and other technologies; see Section 8.2.1.1).
- Work protection and system isolation.
- Confined space entry procedures (including rescue plans).
- Radiological surveys.
- Hold points and back out conditions:
 - Contact with or damage to any pipe, cable, coating or unknown structure;
 - Where water is accumulating;
 - Following a rainstorm (prior to assessment or additional precautions having been taken);
 - Quality assurance hold points prior to backfilling.
- Trenching and shoring design.
- Groundwater and environmental protection.
- Addressing of design basis loading, extreme weather events (e.g. tornadoes, missiles) and pipe supports while
 excavation is in place.
- Excavation procedures (hand digging, vacuum truck, backhoes, etc.).
- Contaminated soil disposal.
- Burial and backfill requirements.
- Training and qualification.

Proper bedding and backfilling processes are required for long term performance of any piping system. Backfilling should be consistent with a consensus standard recognized by the national authorities. Some important concerns are:

- Avoid damaging pipes by excessive impact from heavy compaction equipment. Keep large rocks and other such hard objects out of the fill adjacent to the pipes.
- Bring up haunch and side zones on both sides of the pipe evenly, so that the difference between levels does not typically exceed two compaction layer thicknesses. This ensures the pipes will not be eased slightly out of alignment.
- Avoid running heavy construction equipment over the pipes until a sufficient cushion of material has been placed, approximately 300 mm for normal equipment.
- When using vibrating compaction equipment, allow a cushion of material over the pipe or alternatively turn off the vibration until this level is reached.
- Backfill material selection is important to long term performance of the piping system. The backfill material in contact with the structure should be selected to ensure that its resistivity is as high as practical. Native soils that are not very corrosive can be good candidates for backfill. Areas around CP ground bed systems need special consideration with respect to backfill composition and resistivity.
- Careful inspection/examination records should be kept of backfill operations and quality. Backfill is acceptable if inspections conducted do not reveal evidence of mechanical damage to coatings or component surfaces due to the backfill.

Aluminium or non-metallic pipe such as HDPE can be damaged via backfill material or compaction if care is not taken. Flowable backfill material is available that does not require compaction; however, care must be taken so that the pipe does not float during backfilling. This is accomplished often by filling the pipe or anchoring it during the fill process.

Avoiding excavation is one way to address excavation issues. Liner repairs can often be done without excavation (see Sections 8.2.1.3(e) and 8.2.1.4(d), (e) and (f)) and trenchless technologies such as microtunnelling are an available option for pipe installation. In microtunnelling boring machines (typically 0.6 to 1.5 m in diameter) are launched through an entrance and pipes are pushed or 'jacked' behind the machine. Such technologies avoid the safety issues associated with excavation and allow for installations in areas where excavation would be difficult or undesirable such as below highways, railroads, pavements or environmentally sensitive areas. The disruption and direct costs associated with restoring ground surfaces are virtually eliminated.

8.2.1.3. General repair techniques

(a) Clamps

A mechanical clamp consists of split fittings mechanically joined together to seal off or reinforce a pipe. They can be used to address corrosion or local wall thinning [441]. Clamps can have a variety of shapes (e.g. cylindrical, rectangular), often following the contour of the pipe or component being repaired. They can also be used to enclose components such as flanges, valves, fittings, branches, nozzles, vents or drains.

Mechanical clamps are often available as stock items or they can be custom-made of two half shells, a sealing gasket and bolts, or studs and nuts. The annular space between the clamp and the repaired component can be left either empty or filled, or lined with epoxy, sealant, fibre, refractory materials or other compounds. An example of a clamp with sealant injection via nozzle ports placed around the clamp is shown in Fig. 200.

Mechanical clamps are addressed in, for example, ASME Section XI, Article IWA-4000 and Appendix W [25].

(b) Wrap repairs

Non-metallic composite pipe wraps can be used to repair degraded piping. Layers of composite fabric such as glass, aramid or carbon fibre, impregnated with a high strength adhesive, are wrapped or covered over the degraded area. The layers cure and provide a permanent bond (Fig. 201). ASME standard PCC-2 [441] addresses this type of repair.

Such composite materials allow concrete and steel pipes to be strengthened to take pressures greater than those of their original design at a fraction of the cost and time of alternatives. In the case of 600 mm and larger diameter pipes, access is made through manholes and all operations are conducted internally. If the pipe can be accessed from the outside, or if it cannot be removed from service for the repair, the wrapping can be performed on the outside face of the pipe, resulting in similar benefits.

(c) Inflatable plugs

While not generally suited for long term installation, a wide variety of inflatable airbags and mechanical stoppers are available to accommodate numerous industrial applications (Figs 202 and 203), such as:

- Plumbing operations;
- Creation of airtight seals in drainage applications;



FIG. 200. Mechanical clamp with sealant injection ports (courtesy of EPRI) [12].



FIG. 201. Carbon fibre wrap repair (courtesy of EPRI) [12].



FIG. 202. Typical pipe plug product and applications (courtesy of Petersen Products Co.).

- Low pressure hydrostatic tests;
- On-site thermoforming of bends in ducting and conduit;
- Fibre-optic construction projects;
- Concrete pipe joint testing;
- Debris and animal stopping;
- Weld purging to isolate large volumes in tanks, so minimum volumes are left for argon/nitrogen purging.



FIG. 203. Compressed air connection for plugging a 20 cm gas pipeline; the black pipe spool is the launch cylinder housing the inflatable plug (courtesy of Petersen Products Co.).

(d) Welded metallic pipe repairs

Welded repairs for buried metallic pipe are performed using the same technologies and methods as those for above ground pipe. EPRI provides a good description of the options available in Ref. [12] and so the specifics related to such methods will not be described in detail in this section.

Methods to be considered include simple pipe replacement, a variety of methods to restore cross-sectional thickness to specific damaged areas of a degraded pipe and methods designed to either box in or otherwise contain a leakage area.

Pipe replacement is often the most expensive option as it can require the most excavation. The affected line typically needs to be isolated and drained, although in some cases bypasses can be performed using wet taps. It does provide analysis simplicity as the system is being restored to its original design configuration. Where upgraded or better performing pipe materials are suitable and available, the repair may take the form of installing flanges on old pipe sections and bolting or otherwise attaching new pipe between the two old sections.

Where pipe replacement is not desirable a number of weld repair methods are available to build up or restore pipe cross-section. These include installing patches on a pipe (suitable for pinhole leaks), external weld overlays or internal inlays (buildup of weld material on a pipe's surface; see Fig. 204 for an external overlay), adding corrosion resistant cladding (welding a corrosion resistant material to a pipe, either in the factory or in situ), or (for tanks or large diameter pipes) butt welding in insert plates to essentially replace the original metal in its entirety. Peening and welding may also be suitable for small pinhole leaks.

Where such repairs are not possible a containment approach is more practical. Available methods (Fig. 205) include installing welded encirclement sleeves or leak boxes around the degraded pipe or component. With suitable design such repairs can often be left in extended service.

- (e) Non-welded pipe repairs
 - (i) Joint rehabilitation

Specialized methods have been developed for pipeline joint rehabilitation. One such method is marketed under a patented process known as WEKO-SEAL (Fig. 206). Similar processes are marketed under other names.

The WEKO-SEAL is a flexible rubber leak clamp that provides a non-corrodible, tight seal around the full inside circumference of a leaking pipe joint area. It incorporates a series of proprietary lip seals that are wedged



FIG. 204. Weld overlay profile [442].



FIG. 205. Containment approaches involving weld repairs — pipe sleeves and leak box (courtesy of EPRI) [296].



FIG. 206. WEKO-SEAL being installed into host pipe (courtesy of Miller Pipeline, an MVerge Company).

into place with Type 304 stainless steel bands to create a leakproof fit on either side of a pipe joint. Personnel entry into the pipe is required to install the seal.

The technology has been used on leaking joints in water, wastewater, natural gas and industrial piping from 45 cm up to 5.5 m and larger. Specific materials for the seal are dependent on the fluid carried (e.g. water, wastewater, natural gas or sea water/brackish water).

Advantages of joint repair include:

- Large pipes with leaking joints can be restored to proper functioning using internal joint repair methods;
- Internal joint repairs are more reliable than external joint repairs;
- Cost: an internal joint seal repair costs a fraction of what it costs to use a traditional repair process or any
 pipeline replacement method.

Since joint rehabilitation is a spot repair method, it can be expected to allow the host pipe to remain in service for the remainder of its useful life. A limitation is that this method of repair is limited to leaking joints in large pipes.

(ii) Cured in place pipe liners

Insertion of an inverted liner uses thermoset polymers as a protective or structural lining for underground pipe. The pipe can be steel, cast iron, concrete or other materials, located below ground/buried and with/without original liners (e.g. cement, paint). Pipes repaired can be in the range of 5 cm to 1.8 m diameter.

The pipe is opened at two access points and a liner is inserted at one end and inverted by steam or water pressure to the other end (Figs 207 and 208, ASTM F1216 [444]). The liner is in the form of a sock (i.e. closed at one end).

The new liner is cured in place, effectively becoming a new pipe within the old corroded pipe. Use of CIPP repair methods can provide added structural strength, increased chemical and abrasion resistance, reduced infiltration and exfiltration and reduced pipeline flow resistance.

Epoxies are perhaps the best thermoset polymer for buried pipe rehabilitation due to their versatility, strength, adherence to the host pipe, low coefficient of friction and chemical and abrasion resistance.

Properly applied onto the inside of the host pipe, the polymer adheres well to the pipe and becomes part of a composite system (polymer lining plus the host pipe). The polymer can be reinforced with chopped fibre (i.e. glass, carbon), fibre cloth, preimpregnated carbon or pultruded carbon, thereby making the composite pipe much stronger.

CIPP repairs are typically applied for circulating water piping, service water piping, fire water systems, domestic water systems, storm drains, sewers and condensate in the nuclear industry. This can be the preferred method of repair for small diameter piping where personnel access is impossible.



FIG. 207. Cured in place pipe repair (courtesy of ISTT) [443].



FIG. 208. Cured in place pipe liner being inserted (courtesy of Lanzo Lining Services) and end seal.

EPRI has published a guide for recommended practices in using CIPP for service water repairs [445], a design and qualification guide for Class 3 systems [446] and a report on capacity testing [447].

The design and qualification guide [446] discusses various design equations available, covering such repairs (from ASTM F1216 [444], F2207 [448] and ASME Code Case N589-1 [449]) and some factors to be considered such as internal and external pressure, temperature ranges, system exposure (e.g. acids, solvents, water), soil and groundwater levels, surface (live) loads, host pipe through wall corrosion, creep impacts, strength differences (hoop versus axial), ductility changes, seismic loads (for N589-1) and appropriate safety factors for safety and non-safety-related loads. Gaps in knowledge/technology for CIPP liners for seismic applications are discussed, since although these are addressed in ASME Code Case N589-1 [449], there remain issues with the application of CIPP in safety-related applications in some jurisdictions.

EPRI capacity testing of a section of 20.3 cm (8 in) CIPP demonstrated that average strain at failure is approximately 1.9%, which is much greater than the required value of 0.05% for most of the continental USA [447].

(iii) New liner installation (collapsed liner, slip lining, or Swagelining installation)

Degraded piping can be rehabilitated by the use of a number of methods of installing new liners internal to the original pipe bore. New liners may be HDPE, GRP, PVC, steel or other material. HDPE is well suited for use as a liner material as it can be pulled for long distances (kilometres) and through large radius bends.

Relining can provide effective reuse and life extension of currently installed pipelines without costly retrenching, and the new liners can have improved technical characteristics (e.g. better corrosion or chemical resistance, better durability, less biofouling, better hydraulic performance) than the original pipe. Such repairs minimize pipeline system downtime and can usually reduce the regulatory approval process for building replacement pipelines.

New liners do reduce original pipe diameters to a small extent, but normally, on balance, flow characteristics are improved due to lower flow friction.

Methods generally involve providing access to the pipe section via the fitting or removal of a pipe section and then pulling a new liner into place. The liners come in a collapsed form, a slightly smaller diameter (slip lining repairs), or are reduced in diameter while under pulling tension through a die (Swagelining process).

For collapsed liner repairs the installed, collapsed liner is returned to a round shape, with specific techniques depending on liner material. HDPE liners are typically inflated to a round shape using compressed air; collapsed steel liners for larger diameter pipe are expanded and welded longitudinally and circumferentially. ASTM 1743 [450] describes a collapsed liner process that is very similar to the CIPP repair process described above. This process uses a pulled-in-place liner that does not require inversion but is rather inflated using a calibration hose or by the use of a hydrostatic head or air pressure (Fig. 209).

Slip liner repairs introduce a pipe of smaller diameter into a host pipe without deformation. The smaller size allows for annular clearance.

Swagelining uses a liner which has an outside diameter slightly larger than the ID of the pipe to be lined. After sections of the liner are fused together to form a continuous pipe, the liner is pulled through a reduction die,

which temporarily reduces its diameter. This allows the liner to be pulled through the existing pipeline (Figs 210 and 211).

After the liner has been pulled completely through the pipe, the pulling force is removed and the liner returns towards its original diameter until it presses tightly against the inside wall of the host pipe (Fig. 212). Installation lengths of up to 1500 m are possible in a single operation. Swagelining technology may be employed for a variety of service applications. The polymer pipe is selected to accommodate the required service and operating conditions of the pipeline. Swagelining may be offered in size ranges of 6.3 cm to 152 cm in diameter and, depending upon service and pressure requirements, may be offered for fully structural or semistructural service.

(iv) Spray lining

Spray lining is the application of a sprayed or brushed lining to the inside surface of a degraded pipe. The lining is typically a thermoset resin (with cloth, chopped glass, carbon fibre reinforcement or ceramic particles) or a high strength adhesive. The resulting composite system can have superior qualities to the original pipe. Such linings



Liner inversion versus inflation installation differences

* - Requires inflation bladder or double coated liner

FIG. 209. ASTM F1216 versus F1743 installation.



FIG. 210. High density polyethylene liner being pulled into host pipe (courtesy of Swagelining Ltd).



FIG. 211. Polymer pipe going through reducing die (courtesy of Swagelining Ltd).



FIG. 212. High density polyethylene liner tightening in corroded host pipe (courtesy of Swagelining Ltd).

can provide structural reinforcement, infiltration barriers, abrasion resistance or increases in corrosion allowance. Systems are available to provide tensile strengths as high as 1900 MPa [451].

Application requires pipe entry and so large diameter pipes (greater than 600 mm diameter) are most feasible for personnel application (robotic application is possible for smaller pipes). Patching small pipe portions or a portion of the pipe radius, or entire pipe repair is possible. For larger pipe diameters spray lining is more economical than CIPP lining [451].

Proper adhesion is the largest concern for this type of repair. Precleaning is often necessary and chloride levels must be taken into account for seawater systems. The repair has limitations on operating temperatures due to the limitations of the epoxy or resin. The repair is addressed in ASME Code Case N-589-1 [449].

(v) Composite systems

Composite systems utilizing steel reinforcement and FRP liners are increasingly becoming available for pipeline repair and rehabilitation. A recent example is the StrongPIPE system (Fig. 213) from the Structural Group in Columbia, MD. It is comprised of continuously wound steel tensile wire reinforcement and FRP to provide structural repair and upgrade to pipe segments. The system is applicable to all types of pipelines (PCCP, RCP, RCCP, metallic and ductile) and is installed internally on pipe diameters of 121 cm and larger.

8.2.1.4. Concrete pipe repairs

(a) Clamp and wrap repairs

Like metal pipe (see Sections 8.2.1.3 (a) and (b)), concrete pipe can sometimes be repaired using clamps (Fig. 214) or carbon fibre wraps. Reinforcing clamps can reinforce PCCP with limited numbers of broken prestressing wires and (in conjunction with gaskets) repair pipeline joints [12]. Buried clamps typically require corrosion protection such as mortar or concrete encasement. The pipe must be relatively uniform to ensure proper gasket sealing and must be accessible all around its circumference to install the clamp. Adequate support of the full pipe must be provided during excavation and repair [12].

The main repair advantage of clamp or wrap repairs is that the affected pipe need not be entered nor taken out of service to effect the repair.



- (1) Existing pipe;
- (2) First longitudinal GFRP ply;
- (3) Steel tensile reinforcement;
- (4) Polymer encapsulation;
- (5) Second longitudinal GFRP ply;
- (6) Flexible membrane topcoat.

FIG. 213. StrongPIPE repair system (courtesy of Structural Technologies, LLC) [452].

(b) Post-tensioning repair

Post-tensioning repairs involve applying compressive forces on the exterior of concrete pipe surfaces to restore compressive forces and thus pipe strength that may be lost due to wire breaks within the pipe. The forces are typically applied by new wire strands installed over the existing mortar covering (Fig. 215) or over the concrete core after removal of broken or damaged wires. New wires are often protected with corrosion inhibiting grease, PP sheeting and fibre reinforced shotcrete (Fig. 216). Repair durability can be improved via the addition of CP.



FIG. 214. Clamp repair (courtesy of EDF).



FIG. 215. XPT post-tensioning system (courtesy of Structural Technologies, LLC) [453].



FIG. 216. Palo Verde nuclear power plant repair [454].

Such repairs require excavation of the existing pipe around its full circumference and thus are used only when excavation is feasible and cost effective. The pipeline can often remain full of water and in some cases under some pressure, depending on the extent of distress.

(c) Concrete encasement

Degraded PCCP, RCCP and BWP can be encased with reinforced concrete as an external repair method (Fig. 217). Degraded or damaged concrete is removed prior to completing the encasement. The extent of the excavation and design effort is greater than for other options so this technique has limited use. Encasement is used commonly in marine environments to repair column and beam structures and in some pier and bridge applications [455].

(d) Steel cylinder reinforcement

Steel cylinder reinforcement can be used to reinforce existing pipelines. A steel cylinder is welded around the outside of a degraded pipe (Fig. 218), the ends are temporarily sealed and the annulus is injected with non-shrink grout. The sequence is repeated in 2–6 m sections (cylinders welded together at their ends) until the desired length of piping is repaired.

(e) Carbon fibre reinforced polymer liner

Carbon fibre reinforced polymer (CFRP) liners offer sufficient strength to allow their use as pressure boundary elements in pipe repair situations. Following cleaning via a power wash or sand blast, multiple layers of high strength CFRP fabric impregnated with epoxy adhesive are hand applied onto the concrete inner core wall and then given a final coating (Fig. 219). Such repairs are for large diameter pipes, do not require excavation and are suitable for repair of individual distressed pipes or pipe sections. Hydraulic performance is not affected and material is corrosion resistant. Fibres are unidirectional and thus can only be credited in the direction of loading.



FIG. 217. Reinforced concrete encasement repairs (courtesy of EPRI) [12].



FIG. 218. Cylinder welding and filling with grout (courtesy of National Welding Corp.).



FIG. 219. Hope Creek nuclear power plant carbon fibre reinforced polymer repair (courtesy of Structural Group) [456].

This implies that material should be wrapped in both the circumferential and axial directions, with circumferential fibres being designed for circumferential loads and axial fibres designed for axial loads.

The new liner is essentially a complete replacement for the host pipe, which will continue to degrade over time. As such it must be designed to withstand all forces imparted by the fluid carried, external loads and any tension or bending imparted by the degrading host pipe. Recent applications have been improving long term liner water tightness by incorporating a special final coating over the applied CFRP layers.

The AWWA is developing a standard for material selection, design, installation and quality control and assurance of CFRP for renewal and strengthening of PCCP. A repair guide from the Water Research Foundation is also available [457]. Experience is documented at nuclear power plant s such as Hope Creek, where 17.5 m of 3.7 m diameter prestressed concrete cylinder pipe (in seven segments) were repaired (Fig. 219) using this method [456].

(f) Slip lining repair

Similar to metal piping, concrete piping can be repaired by use of steel, FRP or HDPE slip liners. Refer to Section 8.2.1.3(e) for details on the process.

FRP liners may be inserted as pipes and joined in place. The space between the liner and host pipe may or may not be grouted, depending on design requirements.

(g) Composite repairs

As described in Section 8.2.1.3(e), composite systems of steel reinforcement with a liner have been developed that can be used on larger diameter metallic and concrete pipe.

(h) Spiral wound liners

Spiral wound liners are designed for rehabilitating large diameter pipelines up to 5 m and are not limited to circular shapes. The method uses steel reinforced interlocking profile panels. Liners are installed in situ in the host pipe through a manhole or insertion pit. Profile strips of PVC, steel reinforced PVC or HDPE located on spools above ground are fed into a winding machine. The machine rotates, causing the profile strip edges to interlock and form a watertight liner. The rotational action advances the liner through the host pipe (Fig. 220). In smaller diameter pipes, the liner can be expanded by the winding machine to form a tight fit. Alternatively, a fixed diameter, field-fabricated liner can be installed and the annular space between the host pipe and liner grouted.

The winding machine can remain stationary at the inserting pit in line with the host pipe, or, for larger diameter circular or non-circular applications, the machine can travel along the pipe. The travelling machine installs the liner in contact with the host pipe, forming a close-fit liner that generally conforms to the profile of the host pipe. Or the liner may be installed with a fixed dimension and the annular space between the spiral wound liner and host pipe grouted. To complete the installation, each liner end is sealed to the host pipe.

ASTM standards F1697 [459] and F1741 [460] apply to this repair method.

8.2.1.5. High density polyethylene pipe repairs

The Plastics Pipe Institute (PPI) has published a reference guide on PE pipe that contains a section on HPDE pipe repairs [461].

Full circle band clamps (Fig. 221) may be used for temporary repairs.

Permanent repair methods typically involve patching with HDPE material (permanent attachment is made via saddle fusion (i.e. using heat) or electrofusion), or cutting out the damaged section of pipe and installing a replacement mechanical fitting (for small sections) or a solid sleeve or spool piece (for larger sections). Larger sections can be joined to old piping via mechanical means (solid sleeve repairs), or via electrofusion similar to the original construction. The flange adapter method (Fig. 222) is a combination method whereby flanges are electro-fused onto old piping and then connected to a spool piece by mechanical means.



FIG. 220. Spiral wound line (courtesy of ISTT) [458].



FIG. 221. Full encirclement band clamp for temporary repair (courtesy of Plastics Pipe Institute) [461].



FIG. 222. Flange adapter high density polyethylene repair method (courtesy of Plastics Pipe Institute) [461].

One constraint of any repair method involving heat or electrofusion is that pipe fluid flow must be stopped and the repair area kept dry during the repair process.

Where mechanical connections are used for repairs that grip onto the pipe OD, stiffeners are normally added to the ID to ensure a good connection between coupling and pipe. Additionally, flex restraints (or mechanical restraints) and back up rings may be required on both sides of the coupling to prevent joint leakage.

PPI publishes specific repair procedures such as a generic saddle fusion procedure [462] and a generic butt fusion joining procedure [463]. EPRI has also published a guide on HDPE pipe repair [464]. This guide references a predecessor to the PPI publication mentioned above [461], plus it describes the use of tapered plugs to patch holes and cavity repairs to fill gouges in HPDE pipe as permanent repairs.

8.2.1.6. Pipe casing repairs

Pipe casing repairs normally involve one or more of eliminating metallic contact, casing removal, replacement of carrier pipe, providing supplemental CP to the casing, filling casing with dielectric material, installing a new crossing, monitor casing condition, coating or recoating carrier pipe, replacing end seals or removing electrolyte from inside the casing. NACE SP0200 [129] provides some guidelines.

8.2.1.7. Tank repairs

Tank repairs are typically done via a process of cleaning, inspection, assessment, repair of weakened areas and recoating/relining, followed by a final coating/lining inspection. Some applicable standards are API 1631 [290] and NACE SP0288 [303] for lining inspection and NLPA 631 [393] for the entire inspection and repair process.

Where tank bottoms have degraded an economical repair option can be the installation of a second bottom (liner) above the old degraded bottom. API standard 650 [284], appendix I, provides some guidelines.

8.2.2. Cost comparisons

The National Research Council of Canada performed a study on the relative North American cost comparison of various buried pipe repair techniques in a municipal context [465]. The focus was on near no-dig (or less dig) techniques, including CIPP, microtunnelling, tunnelling, horizontal directional drilling, slip lining, fold-and-reformed pipe, pipe jacking, pipe bursting, spot repair, spiral wound and shotcrete. Some research data are shown in Fig. 223. Other data are available on open cut cost curves versus pipe diameter, costs to thaw frozen pipes, emergency repair costs and rehabilitation of large sewers. The costs of all trenchless rehabilitation/construction methods increase with increases in pipe diameter due to the increased levels of complexity and difficulty of the rehabilitation work. Costs within a nuclear island would be expected to be higher for all technologies.

8.3. PARTS MANAGEMENT

Materials or components may become obsolete when a product gets discontinued, a manufacturer or supplier goes out of business, or applicable standards change, requiring the new product/material to be qualified to more stringent requirements. Refer to table 1 of Ref. [3] for different types of obsolescence and section 5.3 of IAEA Nuclear Energy Series No. NP-T-3.21 [466] for strategies related to procurement in general and obsolescence in particular.



FIG. 223. Cost comparison of various repair methods versus traditional open cut [465].

For underground piping, tanks and CP systems parts management and obsolescence concerns are typically only applicable to linings, coatings, other replaceable components (e.g. anode, rectifier and electrical components in CP systems) and repair material.

A concern with elastomers and some repair materials is limitations on storage shelf life. Coating materials, for example, must typically be used within a specified time from manufacture or shipment and specific provisions (e.g. temperature control) must often be made for their storage to avoid deterioration. Section 3.11 of Ref. [466] covers processes related to storage and warehousing.

Solvents and thinners used in some coating systems should be stored separately from coating materials. Separation of solvents and thinners is of concern because many of these materials have lower flash point temperatures than most coatings and they pose a potential fire hazard. Section 6 of Fire Safety in the Operation of Nuclear Power Plants, IAEA Safety Standards Series No. NS-G-2.1 [467], covers control of combustible materials.

To avoid interference with operations, it is important to ensure that qualified materials and/or components exist and are readily available when the need for repair or replacement arises. Although it may be considered prudent to keep some spare parts and repair materials available at all times, it may not necessarily be economical to do so as some parts and materials have a relatively short shelf life (e.g. elastomers, coatings, some repair materials). Facility purchasing and stocking procedures need to account for parts shelf life issues to ensure availability of usable (i.e. non-life-expired) material when needed.

8.4. REPLACEMENT

Replacement is one form of corrective maintenance and for underground piping and tanks is usually a last resort where repair strategies would be ineffective. Due to the cost of trenching entire replacements are typically not done, with only degraded segments being addressed.

Selection of replacement materials for buried piping is based on compatibility with operating environments, postulated service conditions (including accident conditions), corrosion and degradation history (where available) and material corrosion life. Replacement with a more resistant material should be considered as a measure to prevent fluid side and soil side pipe degradation.

Plants have experienced degradation, most often from forms of corrosion that produced degradation far in excess of the levels anticipated during design. That degradation has required refurbishments, repairs or replacements, with repair or replacement costs ranging from the tens of thousands to tens of millions of dollars. Extensive repair or replacement of underground piping systems introduces additional critical issues and expense.

A number of plants have replaced some or all of their CS lines with 300-series stainless steel due to tuberculation and occlusion of the ID of CS lines that had reduced flow capacity. HDPE, which is immune to corrosion and is highly resistant to fouling, has been used in many replacement projects. Material selection, both for original design and for replacements, will be a strong function of the water source. For example, coated steel, coated cast iron or corrosion resistant alloys will be used for highly corrosive waters, sea water and brackish water. Bare CS or cast iron is often used in fresh waters.

Pipe replacement may be the most costly option to repair degraded buried piping, but can also restore original performance with similar materials, or improved performance with selection of upgraded materials. In some cases, licensing issues may make pipe replacement the best option so as to maintain the system within all code and regulatory requirements.

The most common pipe replacement is to cut out and replace a corroded or damaged section of pipe. In this case, flow in the line will have to be interrupted, the line drained and then cut. As an option to maintain flow, a bypass line may be installed using wet tapping to permit the main line to be replaced without service interruption. As pipe replacement involves cutting and removing a piece of pipe from the line, if removal is not done properly and carefully, joint damage to adjacent pipes may result and cause leakage.

Concrete cylinder pipes are often repaired using closure pieces. Closure pieces are adjustable pipe sections used to facilitate connections for new or replaced piping. They typically consist of two short pipe sections with bell and spigot (male/female) adapters to overlap and connect to the installed pipe and a field-welded connecting butt-strap (Fig. 224) to join the two sections.



FIG. 224. Typical butt-strap connection.

8.5. MAINTENANCE HISTORY

Similar to inspection records and a managed database (see Section 7.6.3.13), maintaining good maintenance records is an important element of an AMP. This helps to document where repairs have been made, identify areas of concern regarding underground piping and tanks, provide OPEX for others, select opportunistic inspection locations during maintenance activities and diagnose problem areas of underground piping and tanks for the future.

The maintenance history of the pipe and the associated support system, as well as the history of CP and its maintenance, are factors affecting the likelihood of OD leaks for the update of risk rankings. Improper maintenance of PCCPs (pump startup/shutdown procedures, valves, check valves, air valves, etc.) may increase the likelihood of breaks related to prestressing wire breaks and loss of prestress in the concrete wall of the pipe.

Areas where repairs have been performed are candidates for additional surveillance as part of the formal AMP to ensure long term repair effectiveness.

9. CONCLUSIONS

Issues related to buried and underground piping and tanks are increasingly important for nuclear facilities. They are receiving increased scrutiny from regulators, internal and external auditors, insurance companies and the public worldwide. This scrutiny often follows leaks or releases to the environment, or is in the context of facility life extension decisions. Operating organizations have in many cases had to expend significant legal, technical, financial and regulatory effort in addressing such concerns, often at short notice.

There are significant differences between buried and non-buried piping and tank systems. Since the systems and equipment involved are 'out of sight', the normal surveillance methods typically employed at nuclear power plants (system performance monitoring and walkdowns by operators and engineering staff) cannot be easily applied. Configuration management of buried piping systems has traditionally not been as well controlled as non-buried and

some operating organizations have had to make significant efforts to accurately locate and model their systems. Additionally, due to soil contact, buried piping is more susceptible to outside diameter corrosion than non-buried.

The nuclear industry has some unique characteristics when compared to others that use buried piping. Nuclear facility piping is more congested, has more diverse material compositions, is installed in a wider variety of sizes and is more impacted on by local grounding arrangements and the location of other services.

Ageing plants have seen increasing numbers of leaks and related events as time progresses. If these are not mitigated there can be unacceptable safety, production and reputational impacts for the affected operating organizations. Proactive mitigation of buried piping degradation can, however, reduce the frequency of such events, the expense of dealing with emergent repairs (and any legal, reputational or regulatory fallout) and will preserve asset value over the long term.

CP can play a key role in the mitigation of steel pipe degradation and is being increasingly used by operating organizations. As buried pipe and tank coating systems reach the end of their service life, CP remains the only effective mitigation strategy that can be applied without significant excavation. Installation of effective CP systems can significantly reduce corrosion rates.

Research is ongoing into improving assessment and inspection methods for buried piping systems (in many cases to minimize the need for expensive excavations), to improve repair methods and to ease the application of non-metallic piping such as HDPE in safety related systems. Such non-metallic piping can have significant benefits over steel piping in many applications.

This publication is based on and describes a well-developed model for a buried piping programme. Operating organizations are encouraged to adopt such a programme for their nuclear facilities and to openly share programme successes and OPEX with other organizations.

Appendix I

IAEA PROGRAMME ON SAFETY ASPECTS OF NUCLEAR POWER PLANT AGEING

To assist Member States in understanding the ageing of SSCs important to safety and in their effective ageing management, the IAEA in 1989 initiated a project related to the safety aspects of nuclear power plant ageing. This project integrated information on the evaluation and management of safety aspects of nuclear power plant ageing that had been generated by Member States into a common knowledge base, derived guidelines and assisted Member States in the application of these guidelines. Results of this work are documented in Refs [314, 468–471].

Some important activities resulting from these efforts and ongoing IAEA work as it relates to underground piping are as follows:

 — 1989: Pilot studies on the management of ageing of nuclear power plant components were initiated to assist Member States in the application of the above ageing management methodology.

Four safety significant components were selected for the studies [469]. These four components represented different safety functions and materials susceptible to different types of ageing degradation, and were:

- Primary nozzles of reactor pressure vessels;
- Motor operated valves;
- Concrete containment buildings;
- Instrumentation and control cables.

Phase 1 studies were completed via Technical Committee meetings held in 1990 and 1991 and consisted of paper assessments of the current state of knowledge on age-related degradation, its detection and mitigation and recommendations for Phase 2 studies. Separate coordinated research programmes were set up for each of the above four components to implement the Phase 2 pilot studies. The overall objective of each pilot study was to identify the dominant ageing mechanisms and to develop an effective strategy for managing ageing effects caused by these mechanisms.

 — 1991: Safety Series publication Data Collection and Record Keeping for the Management of Nuclear Power Plant Ageing [314] was issued.

This publication provides information on data requirements and a system for data collection and record keeping. General data needs, which are grouped into three categories (baseline data, operating history data and maintenance history data), are illustrated by several examples of component-specific data requirements. Actual record keeping systems, including an advanced system, are also described.

 — 1992: Methodology for the Management of Ageing of Nuclear Power Plant Components Important to Safety [472] was published.

Managing the physical ageing of nuclear power plant components important to safety requires predicting and/or detecting when a plant component will have degraded to the point that the required safety margins are threatened (taking appropriate corrective or mitigative actions). The methodology for the management of ageing of plant components important to safety consists of three basic steps:

- Selecting, from the safety perspective, plant components in which ageing should be evaluated, by assessing the effects of ageing degradation on the ability of the components to perform their design functions and crediting existing programmes and activities that manage ageing effectively.
- Performing ageing management studies for the selected components to determine appropriate ageing management actions. The two-phased method reviews current understanding, monitoring and mitigation of

the components' ageing and identifies or develops effective and practical technology and practices for its monitoring and mitigation.

- Using the results of the ageing management studies to take appropriate management actions (i.e. improving existing operations, maintenance practices and design) and to improve relevant codes, standards and regulatory requirements.
- 1999: IAEA AMAT Guidelines, Reference Document for the IAEA Ageing Management Assessment Teams (AMATs), IAEA Services Series No. 4 [473] was issued.

This publication was prepared to document mission guidelines for an IAEA service to provide an assessment of AMPs at a nuclear power plant. This service remains available from the IAEA.

— 2002: Guidance on Ageing Management for Nuclear Power Plants [474] was issued.

This CD-ROM/non-serial publication was prepared to consolidate all IAEA documents related to ageing management at the time of issue into one easy-to-access location.

 — 2006: Nuclear Power Plant Life Management Processes: Guidelines and Practices for Heavy Water Reactors [475] was issued.

This publication included references to some issues associated with FAC in PHWRs (especially feeder thinning) and other plant life management (PLiM) related activities.

- 2007/2008: IAEA recommendations for programmes for the Safety Aspects of Long Term Operation of Water Moderated Reactors [476] and Safe Long Term Operation of Nuclear Power Plants [406] were issued.
- 2008: A first edition of SALTO (safe long term operation) Guidelines for Peer Review of Long Term Operation and Ageing Management of Nuclear Power Plants [477] was issued.

These dealt with ageing management aspects associated with plant life extensions/long term operation of nuclear power plants. The SALTO mission service remains available from the IAEA.

- 2009: Ageing Management for Nuclear Power Plants, IAEA Safety Standards Series No. NS-G-2.12 [3] was issued, along with the associated Proactive Management of Ageing for Nuclear Power Plants, IAEA Safety Reports Series No. 62 [478].
- 2009: IAEA coordinated research project initiated comparing FAC prediction models.
- 2010 to 2013: IGALL project completed to document proven ageing management plans for various world reactor types [479, 480]. The IGALL Working Group for mechanical components dealt with underground piping and produced the generic ageing management programme AMP125: Buried and Underground Piping and Tanks [185], which was provided in the IGALL database on the IAEA website.
- 2014: An updated edition of the SALTO Peer Review Guidelines [481] was issued.

Appendix II

ORGANIC BINDER PROPERTIES

Various organic coating binder types and properties are described below. Classification is by their reaction type (oxygen-reactive, lacquers (solvent evaporation), coreactive, coalescent and condensation). Some comparative resistive properties (including those for inorganic zinc binders) are listed in Table 33.

II.1. OXYGEN-REACTIVE BINDERS

Oxygen-reactive binders are low molecular weight resins capable of producing coatings through an intermolecular reaction with oxygen.

- Alkyds:
 - Alkyds are produced by chemically reacting natural drying oils to form a synthetic resin with excellent wetting and adhesion properties, good gloss, drying, flow, levelling and excellent compatibility with many other types of resins.
 - Alkyd coatings are typically classified in three categories depending on the relative fraction of drying oil component in the resin:
 - Long oil resins (> 60–70% oil content as noted in DIN 55945¹²);
 - Medium oil resins (40–60% oil content);
 - Short oil resins (< 40% oil content).
 - Properties can range from hard, high gloss, fast drying compositions with excellent gloss and colour retention (short oil alkyds) to more flexible, softer, slower drying resins with somewhat lower gloss (long oil alkyds).
 - Alkyds should not be used for heavy-duty anticorrosion coatings since they are susceptible to hydrolysis by alkalis.
- Epoxy:
 - Epoxy resins are organic compounds with more than one epoxide (oxirane) group per molecule which are used to obtain polymers. Epoxy coatings such as coal tar epoxy are one of the most common types of coating.
 - Because of numerous formulation possibilities, epoxy resins are easy to adjust in terms of viscosity and rheological characteristics. Fillers, reinforcements, flame retardants, flexibilizers, pigments, etc., can considerably improve epoxy coating properties and range of application.
 - Epoxy resin usually provides corrosion resistance, adhesion, chemical and heat resistance and excellent mechanical and physical properties.
- Epoxy esters:
 - Epoxy resins react chemically with drying oils to form epoxy esters. The drying oil part of the molecule determines the basic properties of the epoxy ester coatings. The coating dries by oxidation in the same manner as an alkyd.
- Urethane alkyds:
 - Epoxy resins are also chemically combined with drying oils as part of the molecule that further reacts with isocyanates to produce urethane alkyds. Upon application as a liquid coating, the resin-oil combination converts by oxidation to a solid.
- Silicone alkyds:
 - Alkyd resins are combined with silicone molecules to form an excellent weather resistant combination known as silicone alkyd.

¹² Deutsches Institut für Normung E.V., DIN 55945:2016-08, Paints and Varnishes — Additional Terms and Definitions to DIN EN ISO 4618, Deutsches Institut für Normung E.V., Berlin (2016) (in German).

Property	Medium oil alkyd	Vinyl alkyd	Silicone alkyd	Uralkyd	Epoxy ester
Physical properties	Flexible	Tough	Tough	Hard, abrasion resistant	Hard
Water resistance	Fair	Good	Good	Fair	Good
Acid resistance	Fair	Best of group	Fair	Fair	Fair-good
Alkali resistance	Poor	Poor	Poor	Poor	Fair
Salt resistance	Fair	Good	Good	Fair	Good
Solvent resistance	Poor-fair	Fair	Fair	Fair-good	Fair-good
Temperature resistance	Good	Fair–good	Excellent	Fair–good	Good
Weather resistance	Good	Very good	Very good Excellent gloss retention	Fair	Poor
Age resistance	Good	Very good	Very good	Good	Good
Best characteristic	Application	Weather resistance	Weather & heat resistance	Abrasion resistance	Alkali resistance
Poorest characteristic	Chemical resistance	Alkali resistance	Alkali resistance	Chemical resistance	Weathering
Recoatability	Excellent	Difficult	Fair	Difficult	Fair
Primary coating use	Weather resistant coating	Corrosion resistant coating	Corrosion resistant coating	Abrasion resistant coating	Machinery enamel

TABLE 33. COMPARATIVE PROPERTIES OF ALKYD COATINGS [55]

Tables 33 and 35 present comparative properties for these materials, while Table 34 presents resistant properties.

II.2. LACQUERS

Lacquers are coatings converted from a liquid material to a solid film by evaporation of solvents alone. They include PVC polymers, chlorinated rubbers, acrylics and bituminous materials (e.g. asphalts and coal tars).

- PVC polymers are corrosion resistant lacquers made from PVC copolymers. The vinyl molecule is relatively large and effectively dissolves in solvent.
- Chlorinated rubbers have to be modified by other resistant resins to obtain higher solids, decreased brittleness
 and increased adhesion.
- Acrylics are of high molecular weight and may be combined with vinyls to improve exterior weatherability.
- Bituminous asphalts and coal tars are often combined with solvents to form lacquer-type films. Asphalts are mostly aliphatic while coal tars are largely aromatic. They are particularly sensitive to UV (alligatoring degradation mechanism, especially for coal tars), but can provide good corrosion resistance and are usually used in buried applications, to protect external layers and provide waterproofing.
 Table 26 mecants comparative menorities for these metarials.

Table 36 presents comparative properties for these materials.

INDLE JT. INCOL	TANIA TO CHINA TOUT INDIA						
Binder type	Generic type	Alkali	Acid	Water	Weather	Temperature	Primary use
Lacquer	Copolymer-vinyl	н	Е	Щ	Щ	to 65°C	Resistant intermediate and topcoats
	Polyacrylates	Ц	Ц	ц	Ц	to 65°C	Resistant topcoats
	Chlorinated rubber	Е	Е	Щ	Ū	to 60°C	Resistant intermediate
Co-reacting	Epoxy-amine cure	Е	Ð	IJ	Щ	to 93°C	Resistant coatings and linings
	Epoxy-polyamide	Е	Ц	IJ	G	to 93°C	Resistant coatings and linings
	Urethane	ß	Щ	IJ	Щ	to 120°C	Abrasion resistant coatings
	Urethane-aliphatic isocyanate	IJ	щ	IJ	ш	to 120°C	Weather and abrasion resistant topcoats
Condensation	Phenolic	Ρ	Ε	Щ	Ц	to 120°C	Chemical resistant lining
to cure)	Epoxy phenolic	Ц	Ε	Щ	Ц	to 120°C	Chemical resistant lining
	Epoxy-powder coating	G	G	IJ	Ц	to 93°C	Pipe coating and lining
Inorganic	Zinc silicate	Ч	Ч	IJ	Щ	to 315°C	Permanent primer or single coat weather resistant coating
	Glass (fused to metallic substrate)	Н	Е	н	Е	to 260°C	Chemical resistant lining

TABLE 34. RESISTANT PROPERTIES OF BINDERS FOR COATINGS [58]

Rating: E – Excellent; G – Good; F – Fair; P – Poor.

				[]				
Property	Aliphatic amine cure	Polyamide cure	Aromatic amine cure	Phenolic epoxy	Silicone epoxy	Coal tar	· epoxy	Water based epoxy
					I	Amine cure	Polyamide cure	
Physical properties	Hard	Tough	Hard	Hard	Medium-hard	Hard (brittle)	Tough	Tough
Water resistance	Good	Very good	Very good	Excellent	Good-excellent	Excellent	Excellent	Fai-good
Acid resistance	Good	Fair	Very good	Excellent	Good	Good	Good	Fair
Alkali resistance	Good	Very good	Very good	Excellent	Good	Good	Very good	Fair
Salt resistance	Very good	Very good	Very good	Excellent	Very good	Very good	Very good	Fair-good
Solvent resistance (hydrocarbons) Aromatic Aliphatic Oxygenated	Very good Very good Fair	Fair Good Poor	Very good Very good Good	Very good Very good Very good	Good Very good Fair	Poor Good Poor	Poor Good Poor	Poor-fair Good Poor
Temperature resistance	95°C	95°C	120°C	120°C	120°C	95°C	95°C	95°C
Weather resistance	Fair, chalks	Good, chalks	Good	Fair	Very good, chalk resistant	Fair	Fair	Good
Age resistance	Very good	Very good	Very good	Very good	Very good	Very good	Very good	Good
Best characteristic	Strong corrosion resistance	Water and alkali resistance	Chemical resistance	Chemical resistance	Water and weather resistance	Water resistance	Water resistance	Ease of application
Poorest characteristic	Recoatability	Recoatability	Slow cure	Very slow air cure	Recoatability	Black colour Recoatability	Poor recoatability	Proper coalescence
Recoatability	Difficult	Difficult	Difficult	Difficult	Difficult	Difficult	Difficult	Difficult
Primary coating use	Chemical resistance	Water immersion	Chemical coating	Chemical lining	Weather resistance	Water immersion	Water immersion	Atmospheric corrosion

TABLE 35. COMPARATIVE PROPERTIES OF EPOXY COATINGS [55]

			י ע				
Property	Vinyl chloride acetate copolymer	Vinyl acrylic copolymer	Chlorinated rubber resin modified	Chlorinated rubber alkyd modified	Acrylic lacquers	Coal tar	Asphalt
Physical properties	Tough, strong	Tough	Hard	Tough	Hard-flexible	Soft adherent	Soft adherent
Water resistance	Excellent	Good	Very good	Good	Good	Very good	Good
Acid resistance	Excellent	Very good	Very good	Fair	Good	Very good	Very good
Alkali resistance	Excellent	Fair-good	Very good	Poor-fair	Fair	Good	Good
Salt resistance	Excellent	Very good	Very good	Good	Good	Very good	Very good
Solvent resistance (hydrocarbon)							
Aromatic Aliphatic	Poor Good Deer	Poor Good	Poor OK	Poor OK	Poor OK	Poor Fair	Poor Poor
Oxygenated	POOL	r oor	POOL	FOOT	r oor	POOT	POOL
Temperature resistance	Fair 65°C	Fair 65°C	Fair	Fair 60°C	Fair	Depends on softening point	Depends on softening point
Weather resistance	Very good	Excellent	Good	Very good	Excellent	Poor	Good
Age resistance	Excellent	Excellent	Very good	Good	Very good	Good	Good
Best characteristic	Broad chemical resistance	Weather resistance	Water resistance	Drying speed	Clear colour retention, gloss retention	Easy application	Easy application
Poorest characteristic	Critical application	Critical application	Spray application	Chemical resistance	Solvent resistance	Black colour	Black colour
Recoatability	Easy	Easy	Easy	Easy	Easy	Easy	Easy
Primary coating use	Chemical resistant coatings	Exterior chemical resistant coatings	Maintenance coatings	Weather resistant coatings	Weather resistant coatings	Water resistant coatings	Chemical resistant coatings

TABLE 36. COMPARATIVE PROPERTIES OF SOLVENT DRY LACQUERS [55]

II.3. COREACTIVE BINDERS

Coreactive binders are formed from two low molecular weight resins that are combined prior to application to the substrate, where they react to form a very adherent and solid film. They include epoxies (such as coal tar epoxy), polyurethanes and silicone.

Polyurethanes are produced when low molecular weight resins containing alcohol or amine groups are reacted with di-isocyanates into an intermediate resin prepolymer that is then capable of reacting with other groups containing amines, alcohol or even water. Figure 24 in Section 4.2.6.4(e) showed a polyurethane coating being applied and Table 37 presents comparative properties for urethane coatings.

II.4. COALESCENT BINDERS

Coalescent binders are coatings where binders of various resin types are emulsified to form a liquid binder. They are emulsified with water, or less commonly with some other solvent dispersions. When applied to surfaces, the medium evaporates, leaving the coating in such a way that the binder resin gradually flows into itself, or coalesces, to form a continuous film. Table 38 provides a comparison of the properties of typical coalescent binders.

II.5. CONDENSATION BINDERS

Condensation binders are based primarily on resins that interact to form cross linked polymers when subject to sufficient thermal energy. These are also called high-baked materials and are commonly used as tank and pipe linings. Condensation is the release of water during the polymerization process. Table 39 provides a comparison of the properties of typical condensing binders.

II.6. INORGANIC BINDERS

Inorganic binders can form part of an organic coating system. Inorganic binders are mostly inorganic silicates dissolved in water or solvent that react with moisture in the air after their application to a surface. The type of inorganic binder depends on the form of the silicate during the curing period.

	Type 1	Type 2	Type 3	Type 4	Type 5	Aliphatic isocyanate
Property .	Oil modified	Moisture cure	Blocked	Prepolymer catalyst	Two component	cure (non-yellowing)
Physical properties	Very tough	Very tough Abrasion resistant	Tough Abrasion resistant	Tough Abrasion resistant	Tough-hard rubbery	Tough-rubbery
Water resistance ^b	Fair	Good	Good	Fair	Good	Good
Acid resistance ^b	Poor	Fair	Fair	Poor-fair	Fair	Fair
Alkali resistance ^b	Poor	Fair	Fair	Poor	Fair	Fair
Salt resistance ^b	Fair	Fair	Fair	Fair	Fair	Fair
Solvent resistance (hydrocarbon) Aromatic Aliphatic Oxygenated	Fair Fair Poor	Good Good Fair	Good Good Fair	Poor Fair Fair	Good Good Good	Good Good Fair
Temperature resistance	Good (100°C)	Good (120°C)	Good (120°C)	Good (100°C)	Good (120°C)	Good (120°C)
Weather resistance	Good, yellows	Good, yellows	Good, yellows	Good, yellows	Good, some yellowing, chalk	Excellent, good colour and gloss retention
Age resistance	Good	Good	Good	Good	Good	Good
Best characteristic	Exterior, wood coating	Abrasion, impact	Abrasion, impact	Speed of cure	Abrasion, impact	Weather resistance, colour and gloss retention
Poorest characteristic	Oil based chemical resistance	Dependent on humidity for cure	Heat required for cure	Chemical resistance	Two package	
Recoatability	Fair	Difficult	Difficult	Difficult	Difficult	Difficult
Primary coating use	Clear wood coating	Abrasion resistance	Product finish	Abrasion resistance	Abrasion resistance, impact	Exterior coatings
^a Properties of urethanes vary over	a wide range due to the m	any and varied basic polyol	s and isocyanates. The abov	ve listings are only indicat	ive. Manufacturers must h	be contacted for specific

TABLE 37. COMPARATIVE PROPERTIES OF URETHANE COATINGS^a [55]

2 ņ properties of specific materials. Harder coatings are more resistant than softer, more rubbery types. Resistances are for non-immersion conditions. q

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TABLE 38. COMPARATIVE PROPE	RTIES OF COALESCENT EM	AULSION COATINGS (ATMC	SPHERIC USE ONLY) [55]
Property	Vinyl acetate	Vinyl acrylic	Acrylic	Epoxy
Physical properties	Scour resistant	Scour resistant	Scour resistant	Tough
Water resistance	Fair	Good	Good	Good
Acid resistance	NR	NR	NR	Fair
Alkali resistance	NR	NR	NR	Good
Salt resistance	Fair	Fair	Fair	Good
Solvent resistance (hvdrocarbon)				
Aliphatic	Fair	Good	Fair	Good
Aromatic Oxvgenated	NR NR	NR NR	NR NR	Good NR
Temperature resistance	60°C	60°C	60°C	70°C
Weather resistance	Good	Very good	Very good	Fair
Age resistance	Good	Good	Good	Good
Best characteristic	Weather resistant	Weather resistant	Weather resistant	Reasonable corrosion resistance
Poorest characteristic	Porosity	Porosity	Porosity	More porous than solvent base
Recoatability	Good	Good	Good	Fair-good
Primary coating use	Decorative topcoat	Decorative topcoat	Decorative topcoat	Topcoat

NR: Not recommended.

Property	Phenolic	Epoxy phenolics
Physical properties	Very hard	Hard-tough
Water resistance	Excellent 100°C	Excellent 100°C
Acid resistance	Excellent	Excellent
Alkali resistance	Poor	Excellent
Salt resistance	Excellent	Excellent
Solvent resistance (hydrocarbons) Aliphatic Aromatic Oxygenated	Excellent Excellent Very good	Excellent Excellent Good
Temperature resistance	120°C	120°C
Weather resistance	Good, darkens	Good
Age resistance	Excellent	Excellent
Best characteristic	Acid, temperature resistance	Alkali, temperature resistance
Poorest characteristic	Brittle	Poor recoatability
Recoatability	Poor	Poor
Primary coating use	Chemical and food lining	Chemical lining

TABLE 39. COMPARATIVE PROPERTIES OF HEAT-CONDENSING COATINGS [55]

Appendix III

ADDITIONAL PIPING AND TANK RELATED STANDARDS FROM VARIOUS JURISDICTIONS

The following is a list of sample design, fabrication and NDT related standards compiled from various jurisdictions related to piping, coatings, tanks and related components. It is not intended to be an exhaustive list. Note that regulatory requirements, guidelines for buried and underground pipe and tank management and CP standards are listed in Table 21 in the main body of this publication.

	International Standards (ISO)
ISO 3183	Petroleum and Natural Gas Industries — Steel Pipe for Pipeline Transportation Systems
ISO 3452	Non-destructive Testing — Penetrant Testing
ISO 8491	Metallic Materials — Tube (In Full Section) — Bend Test
ISO 8492	Metallic Materials — Tube — Flattening Test
ISO 8493	Metallic Materials — Tube — Drift-Expanding Test
ISO 10893	Non-destructive Testing of Steel Tubes
ISO 10931	Plastics Piping Systems for Industrial Applications — Poly(Vinylidene Fluoride) (PVDF) — Specifications for Components and the System
ISO 11699	Non-destructive Testing — Industrial Radiographic Film
ISO 11961	Petroleum and Natural Gas Industries — Steel Drill Pipe
ISO 15607	Specification and Qualification of Welding Procedures for Metallic Materials — General Rules
ISO 15609	Specification and Qualification of Welding Procedures for Metallic Materials — Welding Procedure Specification
ISO 21809-1	Petroleum and Natural Gas Industries — External Coatings for Buried or Submerged Pipelines Used in Pipeline Transportation Systems — Part 1: Polyolefin Coatings (3-Layer PE and 3-Layer PP)
ISO/FDIS 21809-2	Petroleum and Natural Gas Industries — External Coatings for Buried or Submerged Pipelines Used in Pipeline Transportation Systems — Part 2: Single Layer Fusion-Bonded Epoxy Coatings
ISO 21809-3	Petroleum and Natural Gas Industries — External Coatings for Buried or Submerged Pipelines Used in Pipeline Transportation Systems — Part 3: Field Joint Coatings
ISO 21809-4	Petroleum and Natural Gas Industries — External Coatings for Buried or Submerged Pipelines Used in Pipeline Transportation Systems — Part 4: Polyethylene Coatings (2-Layer PE)
ISO 21809-5	Petroleum and Natural Gas Industries — External Coatings for Buried or Submerged Pipelines Used in Pipeline Transportation Systems — Part 5: External Concrete Coatings
ISO/NP 21809-6 (under development)	Petroleum and Natural Gas Industries — External Coatings for Buried or Submerged Pipelines Used in Pipeline Transportation Systems — Part 6: Multilayer FBE
ISO 23279	Non-destructive Testing of Welds — Ultrasonic Testing — Characterization of Indications in Welds

	US Codes and Standards
	API (American Petroleum Institute)
A PI Spec 5I	Specification for Line Dine
ADI Spec 5D	Specification for Diraling Values
API Spec 6D	Specification for Pipeline valves
API 570	Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems
RP 1110	Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide [289]
	ASM (American Society for Metals)
ASM Handbook Vol. 01	Properties
ASM Handbook Vol. 06	Welding, Brazing and Soldering
ASM Handbook Vol. 13	Corrosion
ASM Handbook Vol. 17	Non-destructive Evaluation and Quality Control [339]
	ASME (American Society of Mechanical Engineers)
ASME B16 Dimensional Codes	5
ASME B16.1	Gray Iron Pipe Flanges and Flanged Fittings Classes 25, 125, and 250
ASME B16.3	Malleable Iron Threaded Fittings Classes 150 and 300
ASME B16.4	Gray Iron Threaded Fittings Classes 125 and 250
ASME B16.5	Pipe Flanges and Flanged Fittings NPS 1/2 Through NPS 24
ASME B16.12	Cast Iron Threaded Drainage Fittings
ASME B16.15	Cast Copper Alloy Threaded Fittings Classes 125 and 250
ASME B16.42	Ductile Iron Pipe Flanges and Flanged Fittings Classes 150 and 300
ASME B16.47	Large Diameter Steel Flanges NPS 26 Through NPS 60
ASME B31	Piping Codes
ASME B31.1	Power Piping [218]
ASME B31.3	Process Piping [219]
ASME B31.4	Pipeline Transportation Systems for Liquids and Slurries
ASME B31.5	Refrigeration Piping and Heat Transfer Components
ASME B31.7	Nuclear Power Piping
ASME B31.9	Building Services Piping [220]
ASME B31.12	Hydrogen Piping and Pipelines

US Codes and Standards (cont.) ASNT (American Society for Non-destructive Testing) ASNT Handbook Vol. 1 Leak Testing [348] ASNT Handbook Vol. 2 Liquid Penetrant Testing [350] ASNT Handbook Vol. 3 Infrared and Thermal Testing [349] ASNT Handbook Vol. 4 Radiographic Testing [482] ASNT Handbook Vol. 5 Electromagnetic Testing [369] ASNT Handbook Vol. 6 Acoustic Emission Testing [483] ASNT Handbook Vol. 7 Ultrasonic Testing [484] ASNT Handbook Vol. 8 Magnetic Testing [485] ASNT Handbook Vol. 9 Visual Testing [486] ASNT Handbook Vol. 10 NDT Overview [487] **ASTM (American Society for Testing Materials)** A53 Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless A74 Standard Specification for Cast Iron Soil Pipe and Fittings Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service A106 A126 Standard Specification for Gray Iron Castings for Valves, Flanges, and Pipe Fittings

- A134 Standard Specification for Pipe, Steel, Electric-Fusion (Arc)-Welded (Sizes NPS 16 and Over)
- A135 Standard Specification for Electric-Resistance-Welded Steel Pipe
- A139 Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe (NPS 4 and Over)
- A182 Standard Specification for Forged or Rolled Alloy and Stainless Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service
- A252 Standard Specification for Welded and Seamless Steel Pipe Piles
- A312 Standard Specification for Seamless, Welded, and Heavily Cold Worked Austenitic Stainless Steel Pipes
- A333 Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service and Other Applications with Required Notch Toughness
- A338 Standard Specification for Malleable Iron Flanges, Pipe Fittings, and Valve Parts for Railroad, Marine, and Other Heavy Duty Service at Temperatures up to 650°F (345°C)
- A369 Standard Specification for Carbon and Ferritic Alloy Steel Forged and Bored Pipe for High-Temperature Service
- A376 Standard Specification for Seamless Austenitic Steel Pipe for High-Temperature Service
- A377 Standard Index of Specifications for Ductile-Iron Pressure Pipe
| US Codes and Standards (cont.) | | |
|--------------------------------|---|--|
| A409 | Standard Specification for Welded Large Diameter Austenitic Steel Pipe for Corrosive or High-Temperature Service | |
| A524 | Standard Specification for Seamless Carbon Steel Pipe for Atmospheric and Lower Temperatures | |
| A530 | Standard Specification for General Requirements for Specialized Carbon and Alloy Steel Pipe | |
| A648 | Standard Specification for Steel Wire, Hard-Drawn for Prestressed Concrete Pipe | |
| A674 | Standard Practice for Polyethylene Encasement for Ductile Iron Pipe for Water or Other Liquids | |
| A694 | Standard Specification for Carbon and Alloy Steel Forgings for Pipe Flanges, Fittings, Valves, and Parts for High-Pressure Transmission Service | |
| A716 | Standard Specification for Ductile Iron Culvert Pipe | |
| A733 | Standard Specification for Welded and Seamless Carbon Steel and Austenitic Stainless Steel Pipe Nipples | |
| A742 | Standard Specification for Steel Sheet, Metallic Coated and Polymer Precoated for Corrugated Steel Pipe | |
| A746 | Standard Specification for Ductile Iron Gravity Sewer Pipe | |
| A760 | Standard Specification for Corrugated Steel Pipe, Metallic-Coated for Sewers and Drains | |
| A762 | Standard Specification for Corrugated Steel Pipe, Polymer Precoated for Sewers and Drains | |
| A790 | Standard Specification for Seamless and Welded Ferritic/Austenitic Stainless Steel Pipe | |
| A813 | Standard Specification for Single- or Double-Welded Austenitic Stainless Steel Pipe | |
| A814 | Standard Specification for Cold-Worked Welded Austenitic Stainless Steel Pipe | |
| A849 | Standard Specification for Post-Applied Coatings, Pavings, and Linings for Corrugated Steel Sewer and Drainage Pipe | |
| A862 | Standard Practice for Application of Asphalt Coatings to Corrugated Steel Sewer and Drainage Pipe | |
| A865 | Standard Specification for Threaded Couplings, Steel, Black or Zinc-Coated (Galvanized) Welded or Seamless, for Use in Steel Pipe Joints | |
| A872 | Standard Specification for Centrifugally Cast Ferritic/Austenitic Stainless Steel Pipe for Corrosive Environments | |
| A885 | Specification for Steel Sheet, Zinc and Aramid Fiber Composite Coated for Corrugated Steel Sewer,
Culvert, and Underdrain Pipe (withdrawn 2006 as pipe no longer manufactured) | |
| A888 | Standard Specification for Hubless Cast Iron Soil Pipe and Fittings for Sanitary and Storm Drain, Waste, and Vent Piping Applications | |
| A926 | Standard Test Method for Comparing the Abrasion Resistance of Coating Materials for Corrugated Metal Pipe | |
| A928 | Standard Specification for Ferritic/Austenitic (Duplex) Stainless Steel Pipe Electric Fusion Welded with Addition of Filler Metal | |
| A929 | Standard Specification for Steel Sheet, Metallic-Coated by the Hot-Dip Process for Corrugated Steel Pipe | |

US Codes and Standards (cont.)			
A930	Standard Practice for Life-Cycle Cost Analysis of Corrugated Metal Pipe Used for Culverts, Storm Sewers, and Other Buried Conduits		
A972	Standard Specification for Fusion Bonded Epoxy-Coated Pipe Piles		
A999	Standard Specification for General Requirements for Alloy and Stainless Steel Pipe		
C856	Standard Practice for Petrographic Examination of Hardened Concrete [388]		
D2855	Standard Practice for Making Solvent-Cemented Joints with Poly(Vinyl Chloride) (PVC) Pipe and Fittings		
D3035	Standard Specification for Polyethylene (PE) Plastic Pipe (DR-PR) Based on Controlled Outside Diameter		
F714	Standard Specification for Polyethylene (PE) Plastic Pipe (DR-PR) Based on Outside Diameter [488]		
F1697	Standard Specification for Poly(Vinyl Chloride) (PVC) Profile Strip for Machine Spiral-Wound Liner Pipe Rehabilitation of Existing Sewers and Conduit [459]		
F1741	Standard Practice for Installation of Machine Spiral Wound Poly (Vinyl Chloride) (PVC) Liner Pipe for Rehabilitation of Existing Sewers and Conduits [460]		
F1743	Standard Practice for Rehabilitation of Existing Pipelines and Conduits by Pulled-in-Place Installation of Cured-in-Place Thermosetting Resin Pipe (CIPP) [450]		
F2620	Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings		
	AWWA (American Water Works Association)		
M9	Concrete Pressure Pipe [34]		
M11	Steel Pipe — A Guide for Design and Installation [222]		
M23	PVC Pipe — Design and Installation [223]		
M28	Cleaning and Lining Water Mains [437]		
M41	Ductile-Iron Pipe and Fittings [489]		
M45	Fiberglass Pipe Design [224]		
M55	PE Pipe — Design and Installation [490]		
C115	Flanged Ductile-Iron Pipe With Ductile-Iron or Gray-Iron Threaded Flanges		
C150	Thickness Design of Ductile-Iron Pipe		
C151	Ductile-Iron Pipe, Centrifugally Cast		
C200	Steel Water Pipe — 6 in (150 mm) and Larger		
C206	Field Welding of Steel Water Pipe		
C207	Steel Pipe Flanges for Waterworks Service — Sizes 4 in. Through 144 in (100 mm Through 3600 mm)		
C220	Stainless-Steel Pipe — ½ in (13 mm) and Larger		
C228	Stainless-Steel Pipe Flanges for Water Service — Sizes 2 in. Through 72 in (50 mm Through 1800 mm)		

US Codes and Standards (cont.)			
C300	Reinforced Concrete Pressure Pipe, Steel-Cylinder Type [37]		
C301	Prestressed Concrete Pressure Pipe, Steel-Cylinder Type [35]		
C302	Reinforced Concrete Pressure Pipe, Noncylinder Type [38]		
C303	Concrete Pressure Pipe, Bar-Wrapped, Steel-Cylinder Type [39]		
C304	Design of Prestressed Concrete Cylinder Pipe [36]		
C950	Fiberglass Pressure Pipe [491]		
	MSS (Manufacturers Standardization Society)		
SP-43	Wrought and Fabricated Butt-Welding Fittings for Low Pressure, Corrosion Resistant Applications		
	Petroleum Equipment Institute (PEI)		
RP100	Installation of Underground Liquid Storage Systems [492]		
RP300	Installation and Testing of Vapor Recovery Systems at Vehicle Fueling Sites [493]		
Underwriters' Laboratories (UL)			
UL 58	Standard for Steel Underground Tanks for Flammable and Combustible Liquids		
UL 971	Standard for Nonmetallic Underground Piping for Flammable Liquids		
UL 1285	Standard for Pipe and Couplings, Polyvinyl Chloride (PVC), and Oriented Polyvinyl Chloride (PVCO) for Underground Fire Service		
UL 1713	Standard for Safety for Pressure Pipe and Couplings, Glass-Fiber-Reinforced, for Underground Fire Service		
UL 1756	Standard for External Corrosion Protection Systems for Steel Underground Storage Tanks [313]		
UL 1990	Standard for Nonmetallic Underground Conduit with Conductors		
	Canadian Standards		
	Canadian Standards Association, Canada		
CSA B51	Boiler, Pressure Vessel, and Pressure Piping Code [50]		
CSA B 137.3	Rigid Polyvinyl Chloride (PVC) Pipe		
CSA B 137.4	Polyethylene Piping Systems for Gas Service		
CSA W48	Filler Metals and Allied Materials for Metal Arc Welding		
CSA Z245.1	Steel Line Pipe		
CSA Z245.11	Steel Fittings		
CSA Z245.12	Steel Flanges		
CSA Z245.15	Steel Valves		

Canadian Standards (cont.)				
CSA Z245.20	Plant-Applied External Fusion Bond Epoxy Coating for Steel Pipe [65]			
CSA Z245.21	Plant-Applied External Polyethylene Coating for Steel Pipe [78]			
CSA Z245.22	Plant-Applied External Polyurethane Foam Insulation Coating for Steel Pipe [77]			
	Underwriters' Laboratories of Canada (ULC)			
CAN/ULC-S603	Standard for Steel Underground Tanks for Flammable and Combustible Liquids [494]			
CAN/ULC-S603.1	External Corrosion Protection Systems for Steel Underground Tanks for Flammable and Combustible Liquids [235]			
CAN/ULC-S615	Reinforced Plastic Underground Tanks for Flammable and Combustible Liquids [495]			
CAN/ULC-S660	Nonmetallic Underground Piping for Flammable and Combustible Liquids [496]			
	European Standards (EN)			
EN 295	Vitrified Clay Pipe Systems for Drains and Sewers			
EN 545	Ductile Iron Pipes, Fittings, Accessories and Their Joints for Water Pipelines — Requirements and Test Methods			
EN 583	Non-Destructive Testing. Ultrasonic Examination			
EN 598 A1	Ductile Iron Pipes, Fittings, Accessories and Their Joints for Sewerage Applications — Requirements and Test Methods			
EN 639	Common Requirements for Concrete Pressure Pipes, Including Joints and Fittings			
EN 640	Reinforced Concrete Pressure Pipes and Distributed Reinforcement Concrete Pressure Pipes (Non-Cylinder Type), Including Joints and Fittings			
EN 641	Reinforced Concrete Pressure Pipes, Cylinder Type, Including Joints and Fittings			
EN 642	Prestressed Concrete Pressure Pipes, Cylinder and Non-Cylinder, Including Joints, Fittings and Specific Requirement for Prestressing Steel for Pipes			
EN 754	Aluminium and Aluminium Alloys — Cold Drawn Rod/Bar and Tube			
EN 764	Pressure Equipment			
EN 969	Ductile Iron Pipes, Fittings, Accessories and Their Joints for Gas Pipelines — Requirements and Test Methods			
EN 1056	Plastics Piping and Ducting Systems — Plastics Pipes and Fittings — Method for Exposure to Direct (Natural) Weathering			
EN 1092	Flanges and Their Joints. Circular Flanges for Pipes, Valves, Fittings and Accessories, PN Designated			
EN 1119	Plastics Piping Systems — Joints for Glass Reinforced Thermosetting Plastics (GRP) Pipes and Fittings — Test Methods for Leaktightness and Resistance to Damage of Non-Thrust Resistant Flexible Joints with Elastomeric Sealing Elements			
EN 1369	Founding — Magnetic Particle Testing			

European Standards (EN)			
EN 1371	Founding — Liquid Penetrant Testing		
EN 1401	Plastic Piping Systems for Non-Pressure Underground Drainage and Sewerage — Unplasticized Poly(Vinyl Chloride) (PVC-U)		
EN 1593	Non-Destructive Testing — Leak Testing — Bubble Emission Techniques		
EN 1759	Flanges and Their Joints — Circular Flanges for Pipes, Valves, Fittings and Accessories, Class Designated		
EN 1779	Non-Destructive Testing — Leak Testing — Criteria for Method and Technique Selection		
EN 1916	Concrete Pipes and Fittings, Unreinforced, Steel Fibre and Reinforced		
EN 10027	Designation Systems for Steel		
EN 10216	Seamless Steel Tubes for Pressure Purposes — Technical Delivery Conditions		
EN 10226	Pipe Threads where Pressure Tight Joints are Made on the Threads		
EN 10241	Steel Threaded Pipe Fittings		
EN 10242	Threaded Pipe Fittings in Malleable Cast Iron		
EN 10253	Butt-Welding Pipe Fittings		
EN 12666	Plastics Piping Systems for Non-Pressure Underground Drainage and Sewerage — Polyethylene (PE)		
EN 12668	Non-Destructive Testing — Characterization and Verification of Ultrasonic Testing Equipment		
EN 13184	Non-Destructive Testing — Leak Testing — Pressure Change Method		
EN 13185	Non-Destructive Testing — Leak Testing — Tracer Gas Method		
EN 13625	Non-Destructive Testing — Leak Test		
EN 14161	Petroleum and Natural Gas Industries — Pipeline Transportation Systems		
EN 14364	Plastics Piping Systems for Drainage and Sewerage with or without Pressure — Glass Reinforced Thermosetting Plastics (GRP) Based on Unsaturated Polyester Resin (UP) — Specifications for Pipes, Fittings and Joints		
EN 14901	Ductile Iron Pipes, Fittings and Accessories — Epoxy Coating (Heavy Duty) of Ductile Iron Fittings and Accessories — Requirements and Test Methods		

BSI Standards (British Standards Institution, UK)

(Besides EN and ISO standards)

BS 143 & 1256	Threaded Pipe Fittings in Malleable Cast Iron and Cast Copper Alloy
BS 437	Specification for Cast Iron Spigot and Socket Drain Pipes and Fittings
BS 1600	Specification for Dimensions of Steel Pipe for the Petroleum Industry — AMD
BS 3074	Specification for Nickel and Nickel Alloys: Seamless Tube

 BSI Standards (British Standards Institution, UK) (cont.)

 BS 3506
 Specification for Unplasticized PVC Pipe — For Industrial Uses — AMD

 BS 3799
 Specification for Steel Pipe Fittings, Screwed and Socket-Welding for the Petroleum Industry

 BS 5391
 Acrylonitrile-Butadiene-styrene (ABS) Pressure Pipe

 BS 5911
 Concrete Pipes and Ancillary Concrete Products

 BS 6464
 Specification for Reinforced Plastics Pipes, Fittings and Joints for Process Plants — AMD

 BS 7159
 Code of Practice for Design and Construction of Glass Reinforced Plastics (GRP) Piping Systems for Individual Plants or Sites

DIN Standards (Deutsches Institut für Normung e.V., Germany)

(Besides EN and ISO standards)

DIN 2848	Lined Flanged Steel Pipes and Flanged Steel or Cast Iron Fittings Rated for Pressures of (PN 10), 25 Bar (PN 25) and 40 Bar (PN 40)	
DIN V 1201	Concrete Pipes and Fittings, Unreinforced, Steel Fibre and Reinforced for Drains and Sewers	
DIN 8076	Pressure Pipelines Made from Thermoplastics Materials — Metal and Plastics Compression Fittings for Polyethylene (PE) Pipes — General Quality Requirements and Testing	
DIN 16867	Glass Fibre Reinforced Polyester Resin (UP-GF) Pipes, Fittings and Joints for Use in Chemical Pipelines; Technical Delivery Conditions	
DIN 16928	Pipes of Thermoplastic Materials; Pipe Joints, Elements for Pipes, Laying; General Directions	
DIN 16966	Glass Fibre Reinforced Polyester Resin (UP-GF) Pipe Fittings and Joints	
DIN 16967	Glass Fibre Reinforced Epoxy Resin (EP-GF) Pipe Fittings and Joints; Elbows, Tees, Dimensions	
DIN 19522	Cast Iron Drainage Pipes and Fittings Without Socket (SML)	
DIN 28601	Ductile Iron Pipes and Fittings — Screwed Socket Joints — Assembly, Sockets, Screw Rings, Sealing Rings and Slip Rings	
DIN 30670	Polyethylene Coatings of Steel Pipes and Fittings — Requirements and Testing [71]	
NF Standards (Normes françaises, France) and Code		

(Besides EN and ISO standards)

SNCT — CODAP	Code for Construction of Unfired Pressure Vessels
SNCT — CODETI	Code français de construction des tuyauteries industrielles (SNCT code for the design of industrial pipelines)

JIS (Japanese Industrial Standards, Japan)		
	A. Civil Engineering and Architecture	
JIS A 5314	Mortar Lining for Ductile Iron Pipes	
JIS A 5350	Fiberglass Reinforced Plastic Mortar Pipes	
JIS A 5371	Precast Unreinforced Concrete Products	
JIS A 5372	Precast Reinforced Concrete Products	
JIS A 5373	Precast Prestressed Concrete Products	
	B. Mechanical Engineering	
JIS B 0151	Iron and Steel Pipe Fittings — Vocabulary	
JIS B 2301	Screwed Type Malleable Cast Iron Pipe Fittings	
JIS B 2302	Screwed Type Steel Pipe Fittings	
JIS B 2303	Screwed Drainage Fittings	
JIS B 2311	Steel Butt-Welding Pipe Fittings for Ordinary Use	
JIS B 2312	Steel Butt-Welding Pipe Fittings	
JIS B 2313	Steel Plate Butt-Welding Pipe Fittings	
JIS B 2316	Steel Socket-Welding Pipe Fittings	
JIS B 2321	Aluminium and Aluminium Alloy Butt-Welding Pipe Fittings	
	G. Ferrous Materials and Metallurgy	
JIS G 3442	Galvanized Steel Pipes for Ordinary Piping	
JIS G 3443-1	Coated Steel Pipes for Water Service — Part 1: Pipes	
JIS G 3443-2	Coated Steel Pipes for Water Service — Part 2: Fittings	
JIS G 3443-3	Coated Steel Pipes for Water Service — Part 3: External Plastic Coatings	
JIS G 3443-4	Coated Steel Pipes for Water Service — Part 4: Internal Epoxy Coatings	
JIS G 3444	Carbon Steel Tubes for General Structural Purposes	
JIS G 3446	Stainless Steel Pipes for Machine and Structural Purposes	
JIS G 3447	Stainless Steel Sanitary Pipes	
JIS G 3447:2009/ Amendment 1:2012	Stainless Steel Sanitary Pipes (Amendment 1)	
JIS G 3448	Light Gauge Stainless Steel Tubes for Ordinary Piping	
JIS G 3452	Carbon Steel Pipes for Ordinary Piping	

JIS (Japanese Industrial Standards, Japan) (cont.)			
JIS G 3454	Carbon Steel Pipes for Pressure Service		
JIS G 3455	Carbon Steel Pipes for High Pressure Service		
JIS G 3456	Carbon Steel Pipes for High Temperature Service		
JIS G 3457	Arc Welded Carbon Steel Pipes		
JIS G 3458	Alloy Steel Pipes		
JIS G 3459	Stainless Steel Pipes		
JIS G 3460	Steel Pipes for Low Temperature Service		
JIS G 3465	Seamless Steel Tubes for Drilling		
JIS G 3466	Carbon Steel Square Pipes for General Structural Purposes		
JIS G 3468	Large Diameter Welded Stainless Steel Pipes		
JIS G 3469	Polyethylene Coated Steel Pipes		
JIS G 3469:2010/ Amendment 1:2013	Polyethylene Coated Steel Pipes (Amendment 1)		
JIS G 3471	Corrugated Steel Pipes		
JIS G 4903	Seamless Nickel–Chromium–Iron Alloy Pipes		
JIS G 5201	Centrifugally Cast Steel Pipes for Welded Structure		
JIS G 5202	Centrifugally Cast Steel Pipes for High Temperature and High Pressure Service		
JIS G 5525	Cast-Iron Drainage Pipes and Fittings		
JIS G 5526	Ductile Iron Pipes		
JIS G 5527	Ductile Iron Fittings		
JIS G 5528	Epoxy-Powder Coating for Interior of Ductile Iron Pipes and Fittings		
JIS G 5528:1984/ Amendment 1:2006	Epoxy-Powder Coating for Interior of Ductile Iron Pipes and Fittings (Amendment 1)		
	H. Non-Ferrous Metals and Metallurgy		
JIS H 3300	Copper and Copper Alloy Seamless Pipes and Tubes		
JIS H 3320	Copper and Copper Alloy Welded Pipes and Tubes		
JIS H 3401	Pipe Fittings of Copper and Copper Alloys		
JIS H 4080	Aluminium and Aluminium Alloys Extruded Tubes and Cold Drawn Tubes		
JIS H 4090	Aluminium and Aluminium Alloy Welded Pipes and Tubes		

JIS (Japanese Industrial Standards, Japan) (cont.)		
JIS H 4311	Lead and Lead Alloy Tubes for Common Industries	
JIS H 4311:1993/ Amendment 1:2006	Lead and Lead Alloy Tubes for Common Industries (Amendment 1)	
JIS H 4552	Nickel and Nickel Alloy Seamless Pipes and Tubes	
JIS H 0502	Method of Eddy Current Testing for Copper and Copper Alloy Pipes and Tubes	
K. Chemical Engineering		
JIS K 6741	Unplasticized Poly(Vinyl Chloride) (PVC-U) Pipes	
JIS K 6742	Unplasticized Poly(Vinyl Chloride) (PVC-U) Pipes for Water Supply	
JIS K 6761	Polyethylene Pipes for General Purposes	
JIS K 6762	Double Wall Polyethylene Pipes for Water Supply	
JIS K 6778	Polybutene (PB) Pipes	

Appendix IV

AGEING MANAGEMENT PRACTICES AND OPERATING EXPERIENCE OF VARIOUS MEMBER STATES

IV.1. CANADA

The Canadian vendor of pressurized heavy water (CANDU) reactors until 2011 was Atomic Energy of Canada Ltd (AECL) — a crown corporation (i.e. wholly owned by the Canadian Government). In 2011 SNC-Lavalin Inc. acquired AECL's CANDU Reactor Division and Candu Energy Inc. was formed to specialize in the design and supply of nuclear reactors, as well as nuclear reactor products and services. The Canadian authority that regulates and licenses nuclear power plants is the Canadian Nuclear Safety Commission (CNSC). CANDU stations are owned and operated by a group of Canadian utilities — Ontario Power Generation, Bruce Power and New Brunswick Power Corporation. Currently there are 19 operating nuclear reactors in Canada and the Canadian nuclear industry is working together to address ageing management of underground piping and tanks.

CNSC has developed Regulatory Document REGDOC-2.6.3 [232] for ageing management of nuclear power plants in Canada. The REGDOC is based on Ref. [3] and identifies ageing management requirements to be considered in the design, construction, commissioning, operation and decommissioning of plants.

Having already been operating for many decades, most nuclear power plants around the globe have experienced ageing degradation and life cycle management issues with their SSCs. These nuclear generating facilities typically have widespread buried components such as piping and tanks. In response to surveillance challenges combined with the recent events of underground water contamination due to corroded underground piping, in 2008 the Electric Power Research Institute (EPRI) formed the BPIG, which has since produced guidelines on how to establish buried piping programmes at plants. Subsequently and in addressing the USNRC mandate as a result of public and US Congressional concerns, the Nuclear Energy Institute (NEI) issued the Buried Pipe Integrity Initiative NEI 09-14 [45] which became the basis for a Nuclear Strategic Issues Advisory Committee (NSIAC) with key milestones for US utilities. See Fig. 225 and Table 40 for a list of key milestones established.

While CANDU plants have followed the EPRI guidelines, they were not included in the NSIAC initiative, nor has there ever been any regulatory mandate to do so by the CNSC. However, some utilities proactively chose to follow industry best practice and adopted the NEI milestones. For instance, Ontario Power Generation put in place its Buried Piping Program Governance in 2008, ahead of the NEI milestone, utilizing the earlier recommendations from EPRI's Report No. 1016456 [498].

The CANDU Owners Group (COG) is a not-for-profit corporation with voluntary funding from CANDU-owning utilities and AECL. Currently, COG membership includes five Canadian and six offshore members. COG activities cover four programmes for collaborative research, information exchange, joint projects and regulatory affairs.

In 2012 at the request of CANDU utilities COG initiated work package 40633, Buried Piping Program Management, which contains a task to benchmark CANDU buried piping programmes against EPRI guidelines, the NSIAC initiative and Exelon (considered within the industry to have one of the most advanced buried piping programmes). The results of the benchmarking study [499] showed that in general CANDU utilities are meeting the requirements of both the EPRI guidelines and NSIAC initiative. It also showed some of the gaps between the CANDU programmes and Exelon's, and detailed some challenges that are being faced by CANDU utilities in programme implementation.

Since 2008 Canadian nuclear power plants have been actively participating in the nuclear industry's buried piping and underground tank related initiatives, such as by attending the EPRI-led BPIG meetings annually. Table 41 provides a chronological development of the buried and underground piping and tanks programme at some selected plants in Canada.

CSA N285.7 [237] is a new standard on the periodic inspection of CANDU nuclear power plant balance of plant (BOP) systems and components. It provides a regulatory framework for buried and underground piping and tanks. The standard defines requirements for the periodic inspection of BOP pressure retaining systems,



FIG. 225. Buried piping management programme and NEI target dates (courtesy of Structural Integrity Associates, Inc.) [497].

	Recommendation step	Implementation dates	
NSIAC action		Buried piping	Underground piping & tanks
Procedures and oversight	Section 1 — Procedures and Oversight	30 Jun. 2010	31 Dec. 2011
Risk ranking/prioritization	Section 2 — Risk Ranking	31 Dec. 2010	30 Jun. 2012
Inspection plan/ Condition assessment plan	Section 3 — Inspection	30 Jun. 2011	31 Dec. 2012
Plan implementation	Section 3 — Inspection Section 4 — Fitness-for-Service Section 5 — Repairs	30 Jun. 2013	30 Jun. 2014
Asset management plan	Section 6 — Prevention, Mitigation, and Long-Term Strategy	31 Dec. 2013	31 Dec. 2014

TABLE 40. NSIAC ACTION PLAN FOR BURIED PIPING (USA)

components and supports that form part of a CANDU nuclear power plant using a risk-informed in-service inspection (RI-ISI) methodology.

TABLE 41. SELECTED CANDU PLANTS — BURIED AND UNDERGROUND PIPING & TANKS PROGRAMME STATUS — ACTIONS COMPLETED

NSIAC action	Bruce Power –	Ontario Power Generation (OPG)		
		Darlington	Pickering	
Programme initiated	2008	2006	2008	
Procedures in place	2009	2006	2011	
Risk ranking/prioritization performed	2009	2006	2011	
Inspection started	2009	2006	2009	
Procedure and risk ranking; updated post NEI 09-14	2012	2012	2012	
Asset management plan	2014	Covered under existing C Management Prog	PG Integrated Ageing ram governance	

IV.2. FRANCE

As of 2013 France had 58 PWRs operating, supplying over 78% of its electricity.

In France, no limit is set on plant operating licence periods but the utility has to obtain a permanent renewal of its licence every ten years subject to numerous and continuous justifications (e.g. safety re-evaluation). EDF, the operator, conducts R&D programmes and specific studies and also implements works on site in order to extend the lifetime of each PWR as far as possible with respect to the safety requirements.

The French safety authority (Autorité de Sûreté Nucléaire — ASN — www.asn.fr), with the help of its technical support (Institut de Radioprotection et de Sûreté Nucléaire — IRSN — www.irsn.fr), checks every ten years whether safety requirements have been met or not, performs a full inspection of plants and gives EDF permission to continue operation if they are satisfied.

Over the past 30 years, several projects conducted by EDF have aimed to study and evaluate the operating life of the 58 PWRs in France and to determine what should be done to extend that life up to 60 years, taking into account the effects of the increase in some safety requirements (due to lessons learned from international events such as earthquakes and accidents: Three Mile Island, Kashiwazaki-Kariwa, Fukushima, etc.).

Starting in 1986, a systematic and continuous work programme (Operation Time Project) was implemented to evaluate as accurately as possible the potential for technical and economic longevity of each of France's nuclear power plants and to take necessary measures to effectively provide improvements wherever possible while maintaining a satisfactory safety level [500]. The project is still running at EDF and addresses four topics: (1) ageing of materials, (2) impacts of severe accidents, (3) safety aspects and (4) economic aspects. It focuses on major components which cannot be replaced and which are considered to be most critical from a safety or economic point of view (containment building, reactor vessel, etc.).

The approach was to characterize the ageing of each sensitive component and to address problems as they occur. This approach was supplemented by a large database of in-service component performance data and experience derived from standardized designs.

IV.2.1. Electricité de France's ageing management programme for buried and underground pipe

Electricité de France's (EDF's) ageing management programme (AMP) for buried pipes, shown in Fig. 226, includes buried and underground pipes, whether these components are safety related or not.

The AMP, established in 2010, follows the NEI 09-14 guidelines [45]. Given the specificity of EDF's nuclear power plant fleet (58 units with six kinds of units), it was decided to test the AMP on a pilot plant before deploying it on the 57 remaining units.



FIG. 226. Electricité de France's ageing management programme for buried and underground pipes (courtesy of EDF). AMP – ageing management programme; NPP – nuclear power plant.

Prior to establishing this AMP the focus was on safety related and environment related pipelines. This will still be enforced after the AMP is implemented.

One ageing phenomenon that has been detected on buried piping for plants bordering the sea is corrosion of the steel cylinder of RCCP. The corrosion observed is usually pitting, which may lead to drilling, due to the presence of chlorides.

The usual inspection technologies used for these components are as follows:

- Elevation inspection;
- ID visual inspection, which is usually done by robots when the pipe diameter is less than 1000 mm and manually otherwise;
- OD visual inspection when the pipe is located within a tunnel;
- Corrosion potential measurements (see Table 42 for sample pipe classification based on half-cell potential measurements);

TABLE 42. ELECTRICITÉ DE FRANCE CLASSIFICATION OF REINFORCED CONCRETE CYLINDER PIPE BASED ON HALF-CELL POTENTIAL MEASUREMENTS [155]

Potential range in mV, Cu/CuSO4 reference electrode	EDF's class	External corrosion of reinforcement and steel cylinder	Perforation of steel cylinder	Recommended actions
-200 to 1000	L	No corrosion (passive state)	None	None
-350 to -200	S	Trace of corrosion on the steel cylinder and/or the reinforcement	Low probability of small perforation	Reinforce control (decrease grid spacing during the next measurement campaign)
-425 to -350	S*	Advanced corrosion on the steel cylinder and/or the reinforcement	High probability of small perforation	Temporarily reinforce or repair pipe
-1000 to -425	R	Severe corrosion on the steel cylinder and/or the reinforcement	Very high probability of small perforation	Temporarily reinforce or repair pipe with high priority

— Water table elevation;

- User defined inspections when needed.

Specific inspections are also made on buried pipe sections that have been replaced. The reinspection interval may evolve depending on the unit, OPEX, analysis trending, etc. Inspections usually focus on:

- Surface defects;
- Cracking;
- Swelling;
- Corrosion weeping;
- Joint defects;
- Settlements.

Changes or evolutions are identified and recorded to improve maintenance, get OPEX and do an analysis trending.

Acceptance criteria are defined for each of these defects. When criteria are not met and depending on the gravity of the defect a maintenance action is carried out. Typical action may range from deep analysis of defects to replacement of the pipe or part of the pipe. Temporary repairs such as clamps may also be used (see Fig. 214).

IV.2.2. Environment related buried pipes

Environment related buried or underground pipes are components carrying hazardous waste. Hazardous waste, known as TRICE in France (initials come from list below), falls under the law of 31 December 1999 [501]. It may be a listed discarded chemical, an off-specification product, an accidental release or a liquid or solid residue from an operation process, which has one or more of the characteristics below:

- Toxic (can leach toxic chemicals as determined by a specific laboratory test);
- Radioactive;
- Ignitable (easily catches fire);
- Corrosive (easily corrodes materials or human tissue);
- Explosive.

Specific maintenance operations have been implemented since 1999 for buried or underground pipes and tanks carrying TRICE products. Inspection of these pipelines is carried out at least every five years.

IV.3. REPUBLIC OF KOREA

IV.3.1. Kori Unit 1 buried piping ageing management programme for continued operation

This programme was designed to conduct surveillance and preventive measures to mitigate corrosion by protecting the external surface of buried CS (including cast iron tube) and concrete piping and tanks and to secure the integrity of buried CS and concrete piping and tanks through ageing inspections. For this, taking into consideration the design, operational characteristics and operation experiences of Kori Unit 1, the existence of related procedures and their suitability and effectiveness were examined. It was confirmed whether the existing programmes could remain valid during the period of extended operation. If needed, additional corrective measures and the plan for their implementation were suggested.

Major items examined for extended operation include (a) preventive measures such as protective coatings and CP systems to prevent exposure to aggressive soil environments, and (b) monitoring through visual inspection for such parameters as external surface coatings and wrapping integrity.

IV.3.1.1. Scope of ageing management programme

The programme relies on preventive measures, such as coating, wrapping and CP, to manage corrosion effects on buried tanks and piping and surveillance, based on NACE Standards RP-0285-95 (now SP-0285 [209]) and RP-0169-96 (now SP-0169 [208]). The programme includes periodic inspection for material loss caused by corrosion of external surfaces of buried CS and concrete piping and tanks. Loss of material in these components, which may be exposed to aggressive soil environments, is caused by general corrosion, pitting, crevice corrosion and MIC. External visual inspections are performed when components become available for inspection due to plant excavation for maintenance or for any other reason.

Kori Unit 1 buried piping to which this AMP is applied is the buried piping of the component cooling seawater system and the firefighting water system. The following systems are excluded from the application: systems installed within trenches and thus not exposed to soil; indoor tanks; and systems not falling under Seismic Class 1.

IV.3.1.2. Preventive actions

When buried piping or tanks are made of metal, ageing management monitoring and preventive actions include external coating, wrapping and CP systems. Component cooling seawater systems use PCCP buried pipes on which prestress is applied onto the direction of circumference so that pressure-resisting capacity is sufficiently maintained according to industry guidelines. Piping is treated with mortar coating to protect PC steel wires and iron plate cylinders within the piping from contacting the aggressive soil environment.

IV.3.1.3. Parameters monitored or inspected

The monitored/inspected parameters applied to the component cooling seawater system buried piping of Kori Unit 1 were selected as follows, taking into consideration relevant codes and standards such as ACI 201.2R Guide to Durable Concrete [502], ACI 349.3R Evaluation of Existing Nuclear Safety Related Concrete Structures [503], standard industry practice and operational experiences of domestic and foreign power plants:

- Visual inspection: damage to coating on internal surface, cracking, loss of material, wear and erosion;
- Close examination: neutralization measurement, chloride content measurement, corrosion (inspection and potential difference measurement) and concrete non-destructive strength measurement;
- External soil analysis: pH concentration, chloride content and sulphate ion concentration;
- Flow cross-section inspection.

Buried piping of the firefighting water system consists of cast iron pipes that have no external coating. The following parameters are monitored or inspected, to which thickness measurement can be added according to the level of corrosion:

- Visual inspection: damage to external surfaces, loss of material and erosion;
- External soil analysis: pH concentration, chloride content and sulphate ion concentration;
- Thickness measurement: internal/external corrosion and loss of material.

IV.3.1.4. Detection of ageing effects

To check whether corrosion has occurred on the external surface of buried piping and whether the piping maintains its intended function, the integrity of coating and wrapping is confirmed through periodic inspections of locations susceptible to corrosion. Concrete pipe degradation is monitored by periodic planned preventive maintenance through inspections of internal piping surfaces (if needed, a water pressure test and inspection of external surfaces are performed after excavation). Additionally, to evaluate indirect corrosion effects on buried piping and tanks, soil around the piping or tanks is collected to analyse pH concentration, chloride content and sulphate ion concentration.

For detection of ageing effects, ACI 349.3R [503] suggests methods, intervals of evaluation and criteria for certification of inspection personnel. Based on this, Kori Unit 1 prepared Procedure 0-8-401 (Inspection Procedure for Aging Phenomena of Nuclear Power Plant Safety Related Concrete Structures) and included the method for detecting degradation and the interval of inspection of component cooling seawater buried piping. Inspections consist of general, periodic and special inspections. General inspection is conducted using simple visual inspection equipment to roughly inspect the outside ageing phenomena of pipes through rounds. Inside inspection of piping is performed during refuelling outages.

Periodic inspection includes detailed inspection that is conducted following the results of interior piping inspections. It is performed for areas showing severe degradation. The inspection interval is five years in principle and inspections are performed during refuelling outages. Special inspections are designed to verify the cause of identified specific ageing phenomena. They are performed when needed with no specified interval based on the judgement of the personnel in charge of inspection in proportion to periodic inspection. The results of the inspections performed in accordance with this programme are entered into the relevant items of the Structure Life Management System (SLMS) for continuous management. Major inspection items by each inspection method are as follows:

— Exterior examination:

- Concrete cracking, peeling, flaking and exfoliation, piping internal degradation, including clogging;
- Corrosion of inside steel material;
- Tightness condition of piping joints.
- Close examination:
 - Neutralization measurement;
 - Chloride content measurement;
 - Corrosion inspection and potential difference measurement;
 - Concrete non-destructive strength measurement;
 - Other needed items (measurement of underground environment, air permeability, etc.).

Firefighting water system buried piping is made of cast iron with no outside coating. Visual inspection is performed to detect its degradation and to evaluate soil corrosiveness around the piping. Piping thickness measurements can be conducted simultaneously.

IV.3.1.5. Monitoring and trending

In the case of Kori Unit 1, monitoring and trending of buried piping are conducted for component cooling seawater system buried piping, to which this programme applies in accordance with Procedure 0-8-401, Chapter 11.10 Management of Results of Examination.

All examination results are entered into relevant items of SLMS under the final responsibility of the personnel in charge of examination. The report of each examination result is compared with the previous report or examined referencing it to establish life management measures, including an evaluation of the integrity of structures and measures for repair or reinforcement.

For firefighting water system buried piping, the first examination will be conducted before the start of extended operation in accordance with the Buried Piping and Tanks Examination Procedure prepared for extended operation and to implement management in accordance with the procedure during the period of extended operation.

IV.3.1.6. Acceptance criteria

Concrete piping should not have cracking, joint corrosion or other degradation. Component cooling seawater system buried piping at Kori Unit 1 is made of concrete and is supposed to undergo maintenance for cracking with a maximum size of more than 0.1 mm, applying the most conservative criteria of ACI 224R [504] for water-control structures among the criteria listed in Procedure 0-8-401. The acceptance criteria for the amount of chloride in concrete material are suggested in ACI 222R-01 [128] and the criteria for evaluating soil corrosion are suggested in the USNRC Review Guidelines.

In the case of firefighting water system buried piping, the acceptance criteria for exterior visual inspection and thickness measurement are included in the Buried Piping and Tanks Examination Procedure. This procedure will be used for ageing management. The criteria for soil corrosiveness evaluation are the same as those for the component cooling seawater system buried piping.

IV.3.1.7. Corrective actions

When the degradation level of buried piping does not satisfy the acceptance criteria, appropriate corrective actions are conducted, including analysis of cause, integrity evaluation or repair. All activities for those corrective actions satisfy the requirements of the Korean Ministry for Education, Science and Technology (MEST) Notice No. 2001-47.

For the ageing phenomena detected by the examination, including the cracking of component cooling seawater buried piping, maintenance is performed based on Procedure 0-8-402 (Repair of NPP Safety-Related Concrete Structures).

IV.3.1.8. Conclusions

In this programme for buried piping and tanks, the appropriateness of the management programme was reviewed based on ten items ranging from the scope of application to operation experiences, which are legal requirements, taking into consideration the design and operation characteristics and operation experience of Kori Unit 1. The review results are as follows:

- Among all buried piping, component cooling seawater system piping that is directly buried and firefighting water system buried piping are given priority in the management programme, using existing periodic examination of safety related structures and the newly established Buried Piping and Tanks Examination Procedure.
- This is an AMP requiring preventive actions. In the case of component cooling seawater system buried piping, to prevent the PC steel wire and steel plate cylinder from directly contacting aggressive soil environments, the outside of the piping is coated with mortar. For buried piping, the parameters monitored or inspected include damage to outside/inside surface coating, cracking, loss of material, wear and erosion. Direct or indirect parameters monitored or inspected are detected by inside/exterior visual inspection and material testing of buried piping, evaluation for corrosiveness of the soil and thickness measurement.
- Most of the implementation items of this programme, including inside/exterior visual inspection and material testing of buried piping, evaluation for corrosiveness of the soil and thickness measurement, are already incorporated into the operation experience and procedures of Kori Unit 1.
- Ageing effects on component cooling seawater system buried piping have been effectively managed since 1999 through such activities as conducting periodic inspections over a cycle of five years. For fire-fighting

water system buried piping, an inspection will be conducted before the start of extended operation in accordance with the newly established inspection procedures.

Therefore, during the period of extended operation, the effects of ageing on buried piping and tanks can be managed and the intended functions of components can be maintained.

IV.3.2. Wolsong Unit 1 buried piping ageing management programme for continued operation

This programme is designed to conduct surveillance and preventive measures to mitigate corrosion by protecting the external surface of buried CS and concrete piping and tanks and to secure the integrity of buried piping and tanks through the detection of ageing related degradation. For this, taking into consideration the design, fabrication characteristics and operation experience of Wolsong Unit 1, the existence of related procedures and their suitability and effectiveness were examined. It was confirmed whether the existing programmes could remain valid during the period of continued operation.

IV.3.2.1. Scope of ageing management programme

This programme focuses on preventive actions and monitoring activities such as coating, wrapping and CP to manage the effects of corrosion on buried piping and tanks. The programme also includes inspections for loss of material caused by corrosion on the outer surfaces of buried CS and concrete piping and tanks. The scope of this AMP covers the buried equipment of Wolsong Unit 1 falling under the safety class. This includes emergency water supply system buried piping, emergency diesel generator system fuel oil storage tanks and transfer piping, component cooling seawater system buried piping and fire protection system buried piping, which are the objects of a backfit rule by the USNRC.

IV.3.2.2. Preventive actions

When buried piping or tanks are made of metal, monitoring and preventive actions include external coating, wrapping and the CP system. Emergency water supply system piping is made of CS. Its outside is coated with CTE and wrapped with glass mat and felt lagging in accordance with AWWA C203 [82], and the CP system is installed. Emergency diesel generator system fuel oil storage tanks and transfer piping are made of CS. The outsides are coated with coal tar epoxy and the CP system is installed. The buried piping of the component cooling seawater system is manufactured using PCCPs onto which prestress is applied in the direction of circumference so that the pressure-resisting capacity is sufficiently maintained. The piping is treated with mortar coating to protect the PC steel wire and iron plate cylinder within the piping from contacting the aggressive soil environment. Fire protection system buried piping is made of CS. Its outside is coated with CTE and wrapped with glass mat and felt lagging in accordance with AWWA C203.

IV.3.2.3. Parameters monitored or inspected

Emergency water supply system buried piping and emergency diesel generator fuel oil storage tank and transfer piping are all coated outside and the CP system is installed. The parameters monitored or inspected for the CS piping and tanks are as follows:

- Visual inspection (when buried piping is exposed due to excavation): damage to coating on external surface;
- External soil analysis: pH concentration, chloride content and sulphate ion concentration;
- CP system inspection: voltage measurement of reference electrode, effect range evaluation of rectifier, integrity evaluation of test box.

The parameters monitored or inspected for component cooling seawater system buried piping are as follows:

— Visual inspection: cracking, loss of material, wear and erosion on internal surface;

- Close inspection: carbonation measurement, chloride content measurement, non-destructive strength test of concrete;
- Groundwater and external soil analysis: pH, chloride content and sulphate ion concentration.

Fire protection system buried piping is coated with CTE on its external surface. The parameters monitored or inspected for it are as follows:

- Visual inspection (when buried piping is exposed due to excavation): damage to coating on external surface;
- External soil analysis: pH, chloride content and sulphate ion concentration.

IV.3.2.4. Detection of ageing effects

The major ageing effects on buried CS piping with external surface coating are corrosion, pitting and coating degradation. AMPs applicable to corrosion and pitting are for CP systems and visual inspection. Visual inspection is an effective method to identify whether corrosion has started on a component's external surfaces and whether its intended function has been maintained. The integrity of coatings and wrappings is checked through inspections on parts where corrosion is suspected. When excavation is conducted for repair or other reasons, visual inspection is implemented for buried piping and tanks. Concrete piping is examined to see if the internal mortar lining is cracked or peeled off. The potential impact of degradation on buried piping is managed through corrosion environment assessment for external soil or groundwater.

Corrosion can occur on emergency water supply system buried piping that is made of CS. However, its external surface is coated with CTE to prevent corrosion and CP is installed. During the continued operation period, to confirm the integrity of the piping the CP system will be inspected and an external soil analysis and, if needed, a visual inspection will be implemented in accordance with the Buried Piping and Tanks Inspection procedure.

The impact of corrosion on emergency diesel generator fuel oil storage tanks and transfer piping is negligible where surfaces are coated with coal tar epoxy, a CP system is installed and periodic leakage inspection (external soil contamination inspection) is implemented in accordance with the stipulations in Paragraph 4, Clause 13 of the Soil Environment Conservation Act. During continued operation, the CP system will be inspected and an external soil analysis and, if needed, visual inspection will be implemented in accordance with the Buried Piping and Tanks Inspection procedure.

Fire protection system buried pipes are made of CS, but the impact of corrosion is also negligible as their surfaces are coated with CTE. During continued operation, as for storage tanks and transfer piping, an external soil analysis and, if needed, visual inspection will be implemented in accordance with the Buried Piping and Tanks Inspection procedure.

For Wolsong Unit 1 component cooling seawater buried piping, inspections are conducted periodically to detect ageing phenomena in accordance with the Jugi-Sul0-001 Nuclear Power Plant Safety-Related Concrete Structures Aging Phenomena Inspection procedure.

Inspections consist of normal, periodic and special inspections. Normal inspections are conducted by visual inspection for ageing phenomena on the inside surface of pipes during refuelling outages. Periodic inspections include detailed inspection. These are performed following the results of inside piping inspection for areas showing severe degradation. The inspection interval is five years in principle and it is performed during refuelling outages. Major inspection items by each inspection method are as follows:

- Visual inspection:
 - Concrete cracking, peeling, flaking and exfoliation and piping internal degradation, including clogging;
 - Corrosion of inside steel material;
 - Tightness condition of piping joints.
- Close examination:
 - Carbonation measurement;
 - Chloride content measurement;
 - Non-destructive strength test of concrete;
 - Other needed items (groundwater or external soil analysis).

IV.3.2.5. Monitoring and trending

In the case of CS piping, changes in the results of external soil (or groundwater) analysis are monitored as is the effect range evaluation of the rectifier as time elapses. The integrity of concrete pipes is confirmed through trend analysis using the results of periodic inspections.

Wolsong Unit 1 component cooling seawater system buried piping, to which this programme applies, goes through monitoring and trending in accordance with the Jugi-Sul0-001 procedure. All examination results are entered into relevant items of the SLMS under the final responsibility of the personnel in charge of examination. The report of each examination result is compared with the previous report or examined referencing it to establish life plan measures, including the evaluation of the integrity of structures and measures for repair or reinforcement. For emergency water supply system and fire protection system buried piping, the first examination was performed in accordance with the Buried Piping and Tanks Inspection procedure. They will be managed in accordance with the procedure during the period of continued operation.

IV.3.2.6. Acceptance criteria

Emergency water supply system, emergency diesel generator fuel oil storage tank and fire protection system buried piping whose outer surfaces are coated with CTE or coal tar epoxy satisfy the acceptance criteria if the performance of their CP systems is maintained and no damage to the outside coating has incurred no damage. The performance criteria for CP systems and the acceptance criteria for outside visual inspections conducted when the coating is damaged are described in detail in the Buried Piping and Tanks Inspection procedure. The criteria for external soil or groundwater analysis are the same as those suggested in the USNRC Review Guidelines.

The component cooling seawater system buried piping of Wolsong Unit 1 is made of concrete and is supposed to undergo repair for cracking when the crack width is more than 0.1 mm, applying the criteria of ACI 224R for water-control structures among the criteria listed in the Jugi-Sul0-001 procedure. The acceptance criteria for the amount of chloride in concrete material are suggested in ACI 222R-96 and the criteria for external soil analysis are the same as those suggested in the USNRC Review Guidelines.

IV.3.2.7. Corrective actions

When the degradation level of buried piping and tanks does not satisfy the acceptance criteria in the Buried Piping and Tanks Inspection procedure, appropriate corrective actions are conducted, including analysis of cause, integrity evaluation or repair. All activities for these corrective actions satisfy MEST Notice No. 2009-37 (Reactor.026) Detailed Requirements for Quality Assurance of Nuclear Reactor Facilities.

For the ageing phenomena detected by the examination, including the cracking of component cooling seawater buried piping, maintenance is performed based on the procedure Sul0-4-302 Repair of Nuclear Power Plant Safety-Related Concrete Structures.

IV.3.2.8. Conclusions

In this programme for buried piping and tanks, the appropriateness of the management programme was reviewed based on ten items ranging from the scope of application to operation experiences, which are legal requirements, taking into consideration the design and fabrication characteristics and operation experience of Wolsong Unit 1. The review results are as follows:

— This is an AMP requiring preventive actions. In the case of component cooling seawater system buried piping, to prevent the PC steel wire and steel plate cylinder from directly contacting aggressive soil environments, the outside of the piping is coated with mortar. Emergency water supply system buried piping and emergency diesel generator fuel oil tank and transfer piping are made of CS. Their outside is coated with CTE or coal tar epoxy and the CP system is installed for each of them. The external surface of fire protection system buried piping is coated with CTE. For buried piping, the parameters monitored or inspected include damage to outside/inside surface coating, cracking and loss of material. Direct or indirect parameters monitored

or inspected are detected by inside/exterior visual inspection (if needed), inspection of the CP system and analysis of soil or underground water.

— Most programme implementation items, including interior/exterior visual inspection and material test of buried piping and analysis of soil, are already incorporated into the operation experience and procedures of Wolsong Unit 1. Therefore, through this programme, buried piping and tank ageing can be managed and the intended component functions can be maintained during the continued operation period.

IV.4. UKRAINE

Ukraine operates 15 WWER units situated at four sites as listed in Table 43.

Nuclear power plant title/ no. of units	Installed electrical power, MWe	Reactor type	Year of commissioning	Designed term of unit end-of-life	Lifetime extension for 10 years since
Zaporizhzhya					
1	1000	WWER-1000/V-320	1984	2014	2014 (expected)
2	1000	WWER-1000/V-320	1985	2015	
3	1000	WWER-1000/V-320	1986	2016	
4	1000	WWER-1000/V-320	1987	2017	
5	1000	WWER-1000/V-320	1989	2019	
6	1000	WWER-1000/V-320	1995	2025	
South Ukraine					
1	1000	WWER-1000/V-302	1982	2012	2012
2	1000	WWER-1000/V-338	1985	2015	
3	1000	WWER-1000/V-320	1989	2019	
Rivne					
1	420	WWER-440/V-213	1980	2010	2010
2	415	WWER-440/V-213	1981	2011	2011
3	1000	WWER-1000/V-320	1986	2017	
4	1000	WWER-1000/V-320	2004	2034	
Khmelnvtskv					
1	1000	WWER-1000/V-320	1987	2018	
2	1000	WWER-1000/V-320	2004	2034	

TABLE 43. WWER UNITS IN OPERATION IN UKRAINE

Regarding the technical specifications of buried piping system of service water for responsible consumers (safety related service water system with partial function of water supply), the following classification is applied to buried piping:

- Group C (PNAE G-7-008-89 [262]);
- 3NO (Class 3 according to Ukraine Safety Code NP 306.2.141-2008 [505]);
- Category I of seismic resistance (PNAE G-5-006-87 [506]).

Buried piping was designed and assembled according to the requirements of the building norms and rules taking into account the single failure criteria and based on a three-channel redundancy scheme.

Typical dimensions are as follows:

- Pipeline Æ 1840–2440 mm, manufactured from sheet steel (VSt3SP5);
- Piping Æ 426–1620 mm, manufactured from steel pipes (St16GS-12 and St20);
- Piping Æ 108-325 mm, manufactured from steel pipes (St20).

Buried piping is protected with anticorrosion multilayer bituminous-polymer insulation up to 9 mm thick, which was originally assigned a design lifetime of 30 years. At four nuclear power plant sites piping is buried 4–8 m below grade and is practically inaccessible for the performance of hydraulic testing and surveys, as required by PNAE G-7-008-89 [262] for pipes of WWER nuclear power plant safety systems.

Nuclear power plant site designers allow buried pipes to be drained to 40% of their total volume for the conducting of internal surveys without performing preliminary strength calculations. Based on some internal survey results, the internal surface of buried piping is covered with carbonate deposits of 1–2 mm thick. This layer makes it difficult to carry out NDT of buried piping in general, and VT in particular. Such a layer does, however, serve as a protection against the corrosion of piping metal by service water. The chemical composition of service water for Ukrainian nuclear power plants is the subject of a branch standard.

Each nuclear power plant site in Ukraine contains a few monitoring wells (in places such as the chambers of lens compensators, etc.) for access to buried piping. Buried piping, according to the technical specifications, is operated at service water temperatures up to +65°C and classified as 'cold' piping. Buried piping is also tested with cyclic pressure loads (reactor operational modes 'start' and 'stop').

Due to the water and soil environment buried piping is affected by corrosion wear-out. At the same time a detailed review of plant faults and violations at Ukraine nuclear power plants gives no record of plant faults due to piping ageing. This is mainly due to very good correspondence of operational conditions to design requirements.

During the operation of Ukraine nuclear power plants within design lifetime, according to the State Nuclear Regulatory Inspectorate of Ukraine, a technical survey of buried piping was performed once every eight years of operation without full scope hydraulic testing, followed by a visual survey from the OD and ID side of buried piping in accessible places.

Under the lifetime extension project at Rivne nuclear power plant Units 1 and 2, it was considered acceptable to perform a technical survey of buried piping as described above. In addition to above ground survey methods, namely visual survey and leak testing, NDT of buried piping metal in survey wells and reactor buildings was applied.

For WWER-1000 unit lifetime extensions, starting with Zaporizhzhya nuclear power plant Unit 1, for technical surveys and the assessment of the technical state of buried piping (Fig. 227) an updated procedure to analyse a set of the necessary parameters was developed to partially compensate for the inapplicability of hydraulic testing. Since access to buried piping is provided in only a few locations, before assessing the condition of buried piping, clustering (similar to risk ranking) of buried piping is performed based on such features as piping diameter, metal type and operational conditions (pressure and temperature range). In each cluster identified, about 5% of the total buried piping is subject to very detailed analysis, including excavation and metal state examination, if necessary. Then the results obtained are assumed to be representative of the full cluster and, similarly, of all buried piping.

This full scope procedure for a condition assessment of buried piping was applied for the first time at Unit 1 of Zaporizhzhya nuclear power plant. Based on the main results the technical state of buried piping is satisfactory and the conclusions are as follows:

- Analysis of buried piping thickness measurements showed 10–20% metal loss wherein all measured wall thicknesses are higher than the minimum allowable;
- Based on piping results, diagnostics and testing there were no defects detected;
- For all buried piping the mechanical properties are within design range;
- Current state of base metal and welds of buried piping meets requirements of norms and technological passports of buried piping.

The decision was made to perform the next technical survey in 2021. The same procedure is to be applied for all buried piping of safety related service water systems in all of Ukraine's nuclear power plants.



FIG. 227. Buried piping technical state assessment under a nuclear power plant unit lifetime extension project. BP – buried pipe; DT – destructive testing; NDT – non-destructive testing; VT – visual testing.

IV.5. UNITED KINGDOM

IV.5.1. Sellafield Ltd: Information on ageing management

The Sellafield site is located in Cumbria in the north-west of England. Sellafield Ltd, which operates the site, is the company responsible for safely delivering decommissioning, reprocessing and nuclear waste management activities on behalf of the Nuclear Decommissioning Authority. The Sellafield site is home to a wide range of interdependent nuclear facilities and operations and includes a complex set of supporting infrastructure, some of which dates back to the early development of the nuclear site.

With a few exceptions, the majority of the pipes and tanks required to support plant operations are located above ground or within accessible ducts. Underground pipes are largely limited to water supply and drainage.

The process for ageing management is the same for underground pipes and tanks as for other plant infrastructure. The process is led by plant system engineers, working alongside engineering managers and maintenance managers. System engineers are the technical owners of an identified system with a basic knowledge across a range of disciplines to understand overall system health and performance.

The health of the system is assessed and managed as follows:

- (1) The system design intent, operating context, service history and future lifetime requirements are identified by reviewing:
 - System file;
 - Configuration baseline;
 - Design documentation;
 - Asset management plans;
 - Plant drawings/schematics;
 - Safety case;
 - Technical basis of maintenance;
 - Qualitative and quantitative risk assessments;
 - Maintenance classification and history data.

The system engineer also performs a preliminary plant walkdown.

- (2) The importance category of the structure, system or component is assessed as being critical, important, significant, marginal or negligible. Each system is broken down into appropriate subsystems or components which have a clear importance categorization and which support a common ageing management approach. The required level of confidence for the condition assessment is based upon the importance category.
- (3) The system engineer assesses the stage of life that the structure, system or component is currently operating in as being one of the following:
 - Stage 1 Post-commissioning ('initial');
 - Stage 2 Risk based ('maturity');
 - Stage 3 Deterministic ('ageing');
 - Stage 4 Monitored ('terminal').

The system engineer assesses and determines the condition by reviewing current condition indicating data and augmenting this with information obtained during a structured plant walkdown. A condition assessment report is produced.

- (4) Taking into account the assessed condition, as well as his or her understanding of the specific degradation mechanisms and future lifetime requirements, the system engineer initiates appropriate actions to minimize, control or mitigate degradation through a combination of reviewing and updating:
 - Operating procedures/controls;
 - Service conditions;
 - Maintenance strategy and asset care arrangements, scheduled restoration and scheduled discard;
 - Design and use of materials.

If the assessment of asset condition (points (1)-(4)) has not provided the required level of confidence then, as part of performing the assessment, the system engineer will have identified and documented a number of actions to close the knowledge gaps. The actions will be aimed at gaining a better understanding of ageing mechanisms with a level of rigour commensurate with satisfying confidence level requirements.

- (5) A 'technical basis of maintenance' is reviewed throughout the equipment life cycle to ensure that ageing mechanisms and failure modes are mitigated using an appropriate strategy to defend against the consequences of failure. Increasing levels of examination, inspection, maintenance and testing (EIM&T), including condition monitoring, are carried out, where appropriate, to ensure that knowledge about ageing mechanisms is maintained at the required level of confidence throughout the life cycle.
- (6) Where the desired level of confidence in asset condition cannot be achieved through improved identification, modelling and monitoring of ageing mechanisms, the system engineer organizes additional assessments and/ or appropriate research and development to mitigate knowledge gaps and improve confidence.

IV.6. UNITED STATES OF AMERICA

IV.6.1. Background

As of April 2014 there were 100 operational nuclear power reactors in the USA with five units under construction. Buried and underground piping and tank integrity activities in the USA can be divided into five areas, all of them coordinated through continuing communications between the parties: (1) utilities and EPRI, (2) the NEI, (3) the USNRC, (4) the Institute of Nuclear Power Operations (INPO) and (5) national codes and standards committees.

IV.6.2. Utilities and the Electric Power Research Institute

Starting in 2007, the EPRI and the nuclear power industry identified buried pipe integrity as a top priority. The utilities, through EPRI, formed the Buried Pipe Integrity Group (BPIG), which is the primary coordinator of nuclear power plant issues related to buried piping. Under BPIG sponsorship, EPRI issued a series of technical reports on buried piping, including documents on recommendations for an effective programme to control buried pipe degradation [227], an balance of plant underground piping and tank reference guide [296], soil side corrosion in buried piping [432], design options [507], inspection and NDE methodologies [298, 508], guided wave inspections [355, 358, 509, 510], AE [343], lessons learned [136], crack evaluation in cement linings and coatings [511], a review of failure initiation mechanisms for Pritec coatings [512], a guide to repair methods [513], a guide for a groundwater protection programme [402] and others.

EPRI also developed BPWORKS software, for management of data related to buried pipe systems and for risk ranking to help plant owners prioritize the inspections of those systems.

Inspections of buried piping, primarily by digging sections of pipe and performing UT based thickness readings, took place through 2014, and inspection results and lessons learned were shared through the BPIG group.

IV.6.3. Nuclear Energy Institute activities

The NEI has issued a guideline for management of underground piping and tank integrity, NEI 09-14 [45]. The guideline is consistent with efforts by the BPIG and EPRI and consists of prioritizing buried piping, performing inspections and evaluating results to determine remaining life, and making run-or-repair decisions.

NEI also has issued a groundwater protection guidance document, NEI 07-07 [403], which identifies actions to improve utility management and responses to instances where inadvertent release of radioactive substances may result in low but detectible levels of plant-related materials in subsurface soils and water. This guidance document includes buried piping within its list of potential site risks.

IV.6.4. US Nuclear Regulatory Commission activities

IV.6.4.1. BP action plan

The USNRC has been active in the area of buried pipe integrity. The USNRC's objectives related to buried piping have been reported as assuring (1) that buried pipes maintain their safety function and (2) that releases from leaks remain below regulatory limits. On 3 September 2009 the USNRC Chairperson issued a directive for USNRC staff to explain the generic activities under way. A series of papers and public meeting presentations has been conducted since 2009, through which the industry provided status of progress and lessons learned. These documents can be accessed online through the USNRC web site (http://www.nrc.gov/reactors/operating/ ops-experience/buried-piping-activities.html). The USNRC has also issued a buried pipe action plan [514] with specific milestones for the collection of reference information, the assessment of industry initiatives, codes and standards activities and regulatory products.

IV.6.4.2. Renewal of operating licences

In the USA the Atomic Energy Act and USNRC regulations limit commercial power reactor licences to a 40-year period and allow these licences to be renewed for an additional 20-year period, with no limit to these renewals. The original 40-year term for reactor licences was based on economic and antitrust considerations, not on technical limitations. Due to this selected period, however, some structures and components may have been engineered on the basis of an expected 40-year service life. In order to ensure safe operation of nuclear power plants it is essential that age-related degradation effects of plant structures, as well as systems and components, be assessed and managed during both the current operating licence period as well as subsequent licence renewal periods [515].

In order to help assure an adequate energy supply, the USNRC has established a timely licence renewal process and clear requirements that are needed to ensure safe plant operation for an extended plant life. These requirements are codified in Parts 54 (License Renewal Rule) [269] and 51 (Environmental Regulations) [516]

of Title 10, Energy, of the Code of Federal Regulations and provide for the renewal of an operating licence for an additional 20 years. The basic principles of licence renewal are that (1) the regulatory process is adequate to ensure the safety of all currently operating plants (with the possible exception of the detrimental effects of ageing) and (2) the plant specific operating basis must be maintained during the renewal term in the same manner and extent as during the original licensing term.

The scope of 10 CFR Part 54 includes: (1) safety related SSCs that are relied upon to maintain the integrity of the reactor coolant pressure boundary, ensure the capability to shut down and maintain a safe shutdown condition and prevent or mitigate off-site exposures comparable to 10 CFR Part 100 [517]; (2) non-safety-related SSCs whose failure could prevent safety related functions as noted above; and (3) SSCs relied upon for compliance with regulations associated with certain regulated events (i.e. fire protection (10 CFR Part 50.48), environmental qualification (10 CFR Part 50.49), pressurized thermal shock (10 CFR Part 50.61), anticipated transients without SCRAM (10 CFR Part 50.62) and station blackout (10 CFR Part 50.63)).

The licence renewal application (LRA) identifies reactor SSCs that would be affected by licence renewal; demonstrates that it can manage the adverse effects of ageing during the renewal period; and analyses the environmental effects of extended reactor operation during the renewal term [269]. Applicants wishing to submit an LRA are responsible for preparing a plant specific LRA that includes both general information, similar to that provided with the initial plant operating licence application and technical information, including an integrated plant assessment (IPA) (10 CFR Part 54.21(a)(1)), time limited ageing analyses (TLAAs) (10 CFR Part 54.3), a supplement to the Final Safety Analysis Report (FSAR) and Technical Specification Changes (10 CFR Part 54.22).

The IPA identifies and lists structures and components subject to an ageing management review (AMR) that perform intended functions without moving parts or without changes in configuration or properties (passive), or that are not subject to replacement based on a qualified life or specified period (long lived). Intended functions are those that in-scope SSCs must be shown to fulfil that would form the basis for including the SSCs within the scope of the assessment. Methods used to identify SSCs subject to an AMR are to be identified. Finally, the applicant must demonstrate that ageing effects will be adequately managed so that their current licensing basis intended function(s) will be maintained consistently with the continuing licence bases for the period of extended operation.

In addition to the rule (10 CFR Part 54), basic documents providing the regulatory recommendations and regulatory framework for ensuring continued plant safety for licence renewal include: Regulatory Guide 1.188, Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses [518], the Generic Aging Lessons Learned (GALL) Report [186] and the Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants [276]. These guidance documents are living documents which are periodically updated. Additional sources of guidance related to licence renewal include: inspection manual chapters, inspection procedures, information notices, licence renewal interim staff guidance, regulatory guides, office instructions, nuclear plant ageing research reports and technical reports in the NUREG series. Provided below is a brief description of the GALL Report that is central to an evaluation of the buried and underground piping and tanks for continued service. Information on the other guidance documents is available at the USNRC web site (http://www.nrc.gov/reactors/operating/licensing/renewal/guidance.html).

The GALL Report lists generic AMRs of SSCs that may be within the scope of LRAs and identifies AMPs that are determined to be acceptable to manage the ageing effects of SSCs, as required by 10 CFR Part 54. The GALL Report provides a technical basis for the standard review plan (SRP) for license renewal and contains the USNRC staff's generic programmes, which have been determined to be adequate to manage the ageing effects associated with the components, materials and environments within the scope of each generic programme. In addition, in a series of system based tables, each structure and/or component is identified as well as its material(s) of construction, environment, ageing effects/mechanisms, acceptable programmes to manage the effects of ageing and whether further evaluation is required. The adequacy of generic AMPs in managing certain ageing effects for particular structures and components is based on a review of ten programme elements of an AMP for licence renewal [276]: scope of programme, preventive actions, parameters monitored or inspected, detection of ageing effects, monitoring and trending, acceptance criteria, corrective actions, confirmation processes, administrative controls and OPEX.

The GALL Report [186] contains 11 chapters and an appendix. Chapter I addresses the application of the ASME Code [46] to licence renewal. Some ageing AMPs referenced in the GALL Report are based entirely or in part on compliance with the requirements of ASME Code Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components [25]. Chapters II through VIII contain summary descriptions and tabulations of AMR evaluations

for a large number of structures and components in major plant systems found in light water reactor nuclear power plants. Chapter IX contains definitions of a selection of standard terms used within the GALL Report. Chapter X contains TLAA evaluations of AMPs under 10 CFR Part 54.21(c)(1)(iii). AMPs are identified in Chapter XI. This chapter provides a description of each of these programmes as well as the evaluation and technical basis related to a review of the ten programme elements of an AMP for licence renewal identified in the SRP-LR [276]. AMP XI.M41 (Buried and Underground Piping and Tanks) [186] manages the ageing effects associated with the external surfaces of buried and underground piping and tanks. The USNRC revised AMP XI.M41 by issuing LR-ISG-2011-03 [198], principally to address plants without CP. AMPs related to managing ageing effects on the internal surfaces of buried and underground piping and tanks, as well as above ground components, include: AMP XI.M20 (Open Cycle Cooling Water System), AMP XI.M21A (Closed Treated Water System), AMP XI.M38 (Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components), AMP XI.M30 (Fuel Oil Chemistry), AMP XI.M27 (Fire Water System) and AMP XI.M2 (Water Chemistry). AMP XI.M33 (The Selective Leaching of Materials) manages selective leaching for both the internal surfaces of buried and above ground components.

IV.6.5. Institute of Nuclear Power Operations

INPO reviews and assesses the implementation of buried pipe programmes at nuclear power plants. INPO is also working with the USNRC and NEI to develop tools to measure the effectiveness of ongoing inspection, evaluation and upgrade programmes.

IV.6.6. National Association of Corrosion Engineers and American Society of Mechanical Engineers

The NACE task groups TG404 and 491 have produced a report on nuclear buried piping corrosion control issues [16] and are in the process of producing a standard practice that defines the design, construction, maintenance and operation of CP systems in nuclear power plants.

The American Society of Mechanical Engineers (ASME) has issued Code Case N-806 [294] for the evaluation of corroded buried piping and is currently working on inspection, mitigation and repair methods and standards.

Appendix V

EXPERIENCE WITH NON-NUCLEAR UNDERGROUND PIPING AND CORROSION

V.1. INTRODUCTION

This appendix provides some pertinent experience from non-nuclear industries related to pipelines and buried and underground piping and tank systems. Any industry dealing with piping or steel, both above ground and underground, is interested in putting in place the right practices for achieving effective corrosion control by utilizing methods that are mainly based on:

- Chemical control of the environment;
- Cathodic protection (CP);
- Protective coatings.

V.2. CONSTRUCTION INDUSTRY

V.2.1. Front end planning for pipeline projects

The Construction Industry Institute has developed a project definition rating index (PDRI) for infrastructure projects [519] that is applicable for pipeline projects. An infrastructure project generally covers a large geographical area and affects multiple jurisdictions and stakeholder groups. The PDRI allows for the assessment of scope completion definitions prior to proceeding with the detailed design and construction of such projects. Infrastructure projects such as pipelines, electrical transmission lines, highways, railroads, aqueducts and communications networks (telephone, data, etc.) have some unique issues such as right-of-way concerns, utility adjustments, environmental hazards, logistic problems and permitting requirements that need to be planned in advance of proceeding with such projects. Use of the PDRI can help identify and manage the risks associated with such projects.

V.2.2. Steel piling experience

Steel piles have been used for many years in a variety of applications to support downward and lateral forces in structures such as buildings, dams or bridges. Corrosion is not a concern in most of these applications. However, there are aggressive environments where corrosion can compromise the structural integrity of piles and cases of severe corrosion damage have been observed [520]. When reviewing the pile life, it is important to understand that the ratio of surface area to weight can significantly impact on the predicted time it takes for corrosion in a pile to reach the weight limit included in the design. The many options for minimizing the effects of corrosive soils include employing zinc coatings, epoxy and other painted coatings; thicker pile selection; impressed current systems; concrete encasement; or installing sacrificial anodes.

Steel piles driven into undisturbed ground (pH > 4) typically require no protection irrespective of the soil types encountered. This also applies to piles driven into harbour, river and sea beds. For piling driven into recent fill soils, and particularly industrial fill soils, some protection may be necessary.

The American Association of State Highway and Transportation Officials (AASHTO) has published a standard practice for assessing corrosion of steel piling in non-marine applications [521]. CP or removal and replacement of corrosive fill are the primary methods for corrosion mitigation for existing pilings. The AASHTO approach starts with site assessment, site investigation (including soil sampling 1 m below the minimum groundwater level), assessment as to the potential of severe corrosion (based on soil resistivity, grain size and pH) and determination

of the necessity for electrochemical testing, corrosion monitoring and mitigation (based on corrosion probe polarization resistance and galvanic probe measurements).

V.3. OIL AND GAS INDUSTRY

The oil and gas industry has long been using pipelines for the transmission of fluid and has therefore built up historical knowledge around corrosion control and surveillance. The vast amount of buried piping is coated, cathodically protected carbon steel (CS) and the fluids contained are relatively non-corrosive when compared to those in nuclear power plants [16].

Pipelines within the oil and gas industry are typically straight long pipes that are electrically isolated. In contrast, piping infrastructure at nuclear generating stations consists of pipe runs that are made of a variety of materials, with shorter lengths, more complex geometry and all connected and grounded electrically for personnel safety purposes. Their design pattern can be jam-packed, with pipes crossing one another and sometimes buried as deep as 2–15 m. Based on these major differences between oil and gas transmission pipelines and buried piping at nuclear power plants, a NACE task group (TG 404) identified four areas that may affect the long term integrity of buried piping within plants: materials of construction, type of coatings, CP system and inspection methods.

Existing methods to monitor for corrosion, while used successfully in the oil and gas industry, have been difficult to apply and interpret when used on buried piping in nuclear power plants. For example, when conducting a close interval potential survey (CIPS), interpreting the data obtained can be complicated by the depth of the buried pipes and the likelihood that the measured value is a mixed potential resulting from numerous pipes and various materials located in the vicinity of the measurement. Monitoring methods that might be successful for oil and gas pipelines will thus not necessarily tell you there is a problem at a plant.

Throughout years of operating experience (OPEX), the oil and gas industry has learned that soil characteristics significantly affect the type and rate of corrosion on underground components (piping, tanks, etc.). Soil moisture content, dissolved salts, oxygen concentration and pH value are the main factors influencing the corrosion of components in contact with soil. They also understand that soil resistivity provides valuable information about soil corrosivity surrounding underground components or under above ground components such as pipelines and tanks [287]. Various resistivity classification ranges are available such as that shown in ASTM G-57 [522] or Table 25 of this publication. ASTM defines measurements of less than 10 Ω ·m as corrosive or severely corrosive, those above and up to 100 Ω ·m as either mildly or moderately corrosive, and those of greater than 100 Ω ·m as progressively less corrosive.

To determine which method of corrosion control needs to be adopted, the oil and gas industry typically performs a full evaluation of component operation/maintenance history. Subsequently, if external or internal corrosion is found to be a concern, control measures (such as CP) will be installed. During these typical component assessments, the following items are investigated:

- Component design and construction history;
- Type of service;
- Inspection and corrosion history;
- Impact of other structures in the component vicinity;
- Soil condition;
- Contents of component;
- Release prevention barrier, if known.

The most popular method of corrosion control within the oil and gas industry is the use of CP, which makes the entire metal surface to be protected act as the cathode of an electrochemical cell. NACE SP0169 [208] describes several criteria that are used to determine if adequate protection has been achieved for buried pipes in soil. Also, the standard method of determining the effectiveness of CP is by measuring component-to-soil potential.

Some other useful standards out of the oil and gas industry include those by API, which are listed in various parts of this publication and in Appendix III.

V.4. RAILROAD AND HIGHWAY CROSSINGS

Railroads and highways have had to deal with underground services for a number of years. The American Petroleum Institute recommended practice RP 1102 [288] Steel Pipelines Crossing Railroads and Highways gives primary emphasis to provisions for public safety. It covers the design, installation, inspection and testing required to ensure safe crossings of steel pipelines under railroads and highways. The provisions of this practice are formulated to protect the facility crossed by the pipeline, as well as to provide adequate design for the safe installation and operation of the pipeline.

V.5. MUNICIPAL WATER AND SEWAGE INDUSTRY

V.5.1. Asset management

Municipalities have extensive experience with managing domestic water supply and sewage buried piping systems. Assessing asset condition is important for predicting future conditions and determining appropriate investment planning. Asset management researchers are developing tools for modelling infrastructure status based on data inputs, such as pipe age, material, soil conditions and number of water main breaks [523]. Asset management analyses are used to help prioritize infrastructure investments by balancing the costs of replacing pipes, pipe failure likelihood, consequences of pipe failure and other variables.

Many cities have developed formal condition assessment systems for their buried assets. Most of these are based on visual inspection results; however, advanced diagnostic tools, NDT methods and integrated decision support tools are becoming more common.

Condition classification can be based on the National Association of College and University Business Officers' facility condition index (FCI), a coarse ratio of the cost of maintenance deficiencies to the current replacement value, as a simplified metric representing asset condition [524]. FCI ranges are grouped as < 0.05 for facilities in good condition, $0.05 \sim 0.10$ for fair and > 0.10 for poor.

The Water Research Centre (WRc), a UK based research organization, has developed a unified Sewerage Rehabilitation Manual that is now available in online form [525]. WRc's manual of sewer condition classification [526] is available for condition classification and defect coding. It is based on closed circuit television (CCTV) inspection and the latest European standard EN 13508-2 [245].

The WRc manual classifies sewers into three categories: A, B and C, based on criticality. Categories depend upon sewer size, traffic flow above the sewer, depth, soil conditions and location (e.g. hospital zone, industrial zone, beneath highways). Category A sewers have extremely expensive failure costs (both direct and indirect) and asset loss would be critical to the municipality or utility. Category B failure costs would be less than for category A and category C failure costs would be the least expensive. For example, a deep sewer in bad ground conditions with a high traffic flow is rated as category A, whereas a shallow sewer in good ground conditions in a low traffic route is rated as category B [527].

The National Research Council of Canada has developed a guide for condition assessment of large sewers > 900 mm [528]. It is similar to the WRc approach but adds some information on failure impact rating and defect coding.

In the USA, the National Association for Sewer Service Companies (NASSCO) developed the Pipeline Assessment and Certification Program in 2004, with WRc assistance, to provide a standardized and consistent way to evaluate sewer pipes using CCTV inspection.

V.5.2. Hydraulic modelling

The water industry has been using hydraulic models for decades to simulate flows and pressures. Newer models can link hydraulic and water quality parameters. Accurate modelling in distribution systems is dependent on input data accuracy. For water utilities with old pipes, substantial effort is necessary to collect and verify information about pipe diameters, materials and locations. However, GIS is becoming more readily available and more accurate and can help with this process. GIS is also helpful for understanding spatial relationships between water quality measurements at different locations in the distribution system over time.

A challenge in hydraulic modelling is determining customer water usage at all points in the distribution system over time. Because meters are generally read on a monthly or quarterly basis, they do not provide real time data. Innovations in automated meter reading may improve the collection of real time data, but there are still significant challenges to data management.

Real time models today are primarily used for energy management and for detecting situations that differ from the baseline, such as water main breaks or large fires. The field has not yet advanced to the level of sophistication necessary to fully automate the operation of a water distribution system, so very few utilities have created real time models of their systems, which requires linking operational data with the model and running repeated simulations.

Appendix VI

SAMPLE BURIED AND UNDERGROUND PIPING HEALTH REPORT

Site specific health reports are recommended for component programmes such as a buried and underground piping and tanks AMP. Individual site reports may be rolled up into a fleet wide report (see Section VI.2) for nuclear operators with more than one site. This appendix documents what such reports might contain.

VI.1. SITE HEALTH REPORTING — RECOMMENDED STRUCTURE AND INDICATORS

This report should be produced by a qualified individual responsible for the buried and underground piping AMP. Such a site level health report would typically contain a cover page, plus sections covering current performance gaps and recovery actions, an overall programme summary and details on indicators covering performance execution and performance initiatives. Report signatories are the report preparer and others as required by the site's management system. Each report section is described in turn below.

VI.1.1. Cover page

The report cover page is designed to provide an overview of all programme activities and recent programme history at the site in question. It typically shows colour ratings for programme execution and initiative sections (often RED, YELLOW, WHITE or GREEN based on issue severity) and overall programme health as determined by the responsible individual and supervisor.

VI.1.2. Performance gaps and recovery status

This section summarizes all areas of concern (e.g. RED and YELLOW areas) in programme execution and initiative sections, including:

- Status of recovery plans and associated actions;
- Projected date when the area(s) will be improved to WHITE.

Some sample wording for such a section is given below:

Performance Gaps and Recovery Status (sample wording):

Overall health of the buried piping programme at the station is YELLOW. This score is the same as from the previous reporting period.

Programme execution is reported as WHITE for this reporting period. This is improved from YELLOW in the last quarter. Direct inspections on buried piping for chlorination, hydrogen and instrument air were completed on units 1 and 2 (these had to be deferred from previous quarters).

Programme action plan progress is reported as YELLOW for this reporting period. This is a decline from WHITE from the previous quarter. The decline was due to several action plan items being deferred due to lack of station resources during an unplanned unit outage. It is expected that the programme area will return to WHITE in QX, 20XX following....

VI.1.3. Overall programme summary

The following information should be included in the overall programme summary section:

- Programme execution successes and challenges during the reporting period;

- Key programme initiatives currently in progress;
- Business risks;
- Needed assistance, if any.

Table 44 shows a possible colour chart methodology in use at one utility to merge programme execution status colour ratings with programme initiative status ratings to obtain an overall programme rating. For example, if for a particular nuclear power plant the programme execution status was 'WHITE' and programme initiative status was 'YELLOW', the overall programme rating would be considered 'YELLOW'.

VI.1.4. Programme execution performance indicators

Performance indicators and metrics for each programme execution area should be developed. Such indicators should:

- Be objective;
- Be industry standard indicators;
- Have defined targets that are benchmarked relative to industry;
- Be easy to understand;
- Measure the status of key programme activities (e.g. preventive maintenance execution).

TABLE 44. SAMPLE PROGRAMME COLOUR CHART

Programme execution status	Programme initiative status	Overall programme rating
	GREEN	GREEN
CREEN	WHITE	WHITE
OKEEN	YELLOW	WHITE
	RED	YELLOW
	GREEN	WHITE
WILLTE	WHITE	WHITE
WHITE	YELLOW	YELLOW
	RED	RED
YELLOW	GREEN	YELLOW
	WHITE	YELLOW
	YELLOW	YELLOW
	RED	RED
RED	GREEN	RED
	WHITE	RED
	YELLOW	RED
	RED	RED

A score and corresponding colour should be assigned for each performance indicator based on actual programme performance. Sample criteria might be:

- Worse than target by more than 10%: colour rating assigned as RED;
- Worse than target by more than 5% but less than 10%: colour rating assigned as YELLOW;
- Within 5% of target: colour rating assigned as WHITE;
- Better than target by 5% or more: colour rating assigned as GREEN.

An overall execution rating for the entire programme (i.e. RED, YELLOW, WHITE or GREEN) would then be developed and recorded on the report cover page.

Some possible execution indicators for a typical buried and underground piping and tanks programme are as follows, with a sample report format in Table 45. As the programme matures and evolves such indicators and targets would change to reflect current priorities.

- Risk ranking completed;
- Indirect inspections completed;
- Direct inspections completed;
- Inspection reports completed;
- Repairs/replacements completed versus scoped;
- Unacceptable wall losses detected or pipe/tank failures.

TABLE 45. SAMPLE SITE PERFORMANCE INDICATOR SUMMARY

Indicator	Benchmark industry target	Target	Score
(1) Risk rankings completed	80%	80%	80%
(2) Indirect inspections completed	100%	100%	100%
(3) Direct inspections completed versus scoped	100%	100%	100%
(4) Inspection reports completed	100%	100%	25%
(5) Replacement/repairs completed versus scoped	100%	100%	100%
(6) Number of through-wall failures	0	0	1

VI.1.5. Programme initiative status

High level initiatives related to the programme should be recorded in this section. Emergent and/or recovery initiatives under way to address all RED or YELLOW programme execution performance indicators (see Section VI.1.4) should also be listed. These actions should be traceable via site work management or action tracking entries, with expected improved colour of the indicator at the completion of each action (e.g. will turn indicator from 'RED' to 'YELLOW').

A colour rating should be assigned to each initiative according to its current status:

- RED: 'At risk' Results were either not achieved or are projected to be not fully achievable;
- YELLOW: 'Threatened' All results are on track to date, but unmitigated risks have been identified which
 may threaten achievement of future results;
- WHITE: 'On track' All results are on track. No unmitigated risks are identified;

- GREEN: 'Better than plan' - Some results have been or will be exceeded and the remainder are all on track. No unmitigated risks have been identified.

Some sample initiative status descriptions are shown in Table 46.

TABLE 46. SAMPLE WORDING OF PROGRAMME INITIATIVE ACTION ITEMS

Initiative	Target completion	Status
(1) Complete remaining inspection of ESW lines in north yard area	Q2 20XX	On track
(2) Issue design package to allow regular robotic access to interior of service water lines	Q3 20XX	Expected delivery one month early
(3) Complete peer review of site programmes with external expert	Q2 20XX	Delayed two months due to expert unavailability

VI.2. FLEET VIEW REPORTING

Senior nuclear managers at multistation utilities require an overview of performance assessment for SSCs on a fleet wide basis. Often this is accomplished via a programme fleet view health report. These reports are presented to nuclear executives of the operator's company for information and to seek support as required (e.g. resources, commitment priority) for action implementation. A sample cover page is shown in Table 47.

VI.2.1. Fleet view reporting — recommended structure and indicators

A typical fleet view report would have the following sections:

VI.2.1.1. Executive summary

A programme overall rating for current and previous periods is shown in this section. Programme achievements, gaps, potential and actual risks and support required from the executive team should also be documented clearly and concisely. Some sample text covering typical performance gaps is below.

Performance Gaps and Recovery Status (sample wording):

Overall health of the fleet buried piping programme is YELLOW. This score is the same as from the previous reporting period.

(1) Section A is reported as YELLOW for this reporting period. This is improved from RED from the last quarter. The improvement was due to completion of previously scheduled peer reviews and self-assessments of the BP programme. It is expected that the programme area will be ranked as WHITE in QX, 20XX following....

(2) Section B is reported as WHITE for this reporting period. This is improved from YELLOW in the last quarter. Direct inspections on buried piping for chlorination, hydrogen and instrument air were completed on units 1 and 2 (these had to be deferred from previous quarters).

(3) Section C is reported as YELLOW for this reporting period. This is a decline from WHITE from the previous quarter. The decline was due to several action plan items being deferred due to lack of station resources during an unplanned unit outage. It is expected that the programme area will return to WHITE in QX, 20XX following....

TABLE 47. SAMPLE FLEET PROGRAMME REPORT COVER PAGE



VI.2.1.2. Programme oversight and leadership indicators

This section covers activities done at a fleet level (supported by individual sites) associated with management of the overall programme. Indicators are developed covering areas such as governance and procedures, staffing, training and continuous improvement. For each indicator, it is recommended that both current and previous ratings be documented.

Some indicators used at one utility that demonstrate levels of programme oversight and leadership are listed below:

- Have governance (i.e. programme document, procedures and standards) and governance support documents (e.g. instructions, forms, templates) been reviewed within the established review cycle as defined in
governance? Are all external requirements, including regulatory and licensing requirements, established and maintained in the programme and supporting documents?

- Have OPEX and internal/external lessons learned been incorporated into the programme in the last 24 months?
- Has the programme been benchmarked against industry best practice in the last 24 months? Does the programme include a controlled set of performance indicators which are aligned with industry standards?
- Is there an effective peer team, working group and/or oversight body established for the programme?
- Is the programme free of significant Level 1 or 2 events initiated in the past 12 months? Are recurrence control actions on schedule with no due date extensions?
- Are internal and external (e.g. nuclear oversight, nuclear regulator, environmental regulator, peer review areas for improvement) audit and inspection finding improvement actions and initiatives which impact on the programme currently on schedule?
- Has observation and coaching been conducted to drive performance improvement in the execution of the programme?
- Have self-assessments been conducted, based on an established schedule, to drive performance improvement in the execution of the programme?
- Have tracking and trending been conducted, based on an established schedule, to drive performance improvement in the execution of the programme?
- Is the programme ownership organization staffed with the correct staff and competencies to ensure the appropriate level of programme oversight, leadership and support in accordance with the business plan?
- Are programme execution organizations staffed with the correct staff and competencies to ensure performance meets expectations in accordance with the business plan?
- Are training and qualification requirements established and up-to-date to execute the programme? Is there evidence that training is being used to improve performance?

VI.2.1.3. Programme execution performance indicators

This section is the rollup of site specific execution indicators (see Section VI.1.4). A typical fleet view roll up might look like Table 48.

VI.2.1.4. Programme action plan

This section is the rollup of site specific initiatives (see Section VI.1.5), plus any additional improvement initiatives managed at a fleet level.

Indicator Benchmark industry target	Benchmark	Station 1		Station 2		Station 3		Fleet	
	Target	Score	Target	Score	Target	Score	Target	Score	
(1) Risk rankings completed	80%	80%	80%	80%	80%	80%	100%	86%	86%
(2) Indirect inspections completed	100%	100%	100%	100%	100%	100%	100%	100%	100%
(3) Direct inspections completed versus scoped	100%	100%	100%	100%	90%	100%	100%	100%	97%
(4) Inspection reports completed	100%	100%	0%	100%	N/A (inspections cancelled)	100%	0%	100%	0%
(5) Replacement/ repairs completed versus scoped	100%	100%	100%	100%	100%	100%	100%	100%	100%
(6) Number of through-wall failures	0	0	1	0	2	0	0	0 per stn	1

TABLE 48. SAMPLE FLEET VIEW PERFORMANCE INDICATOR SUMMARY

ABBREVIATIONS

AAR	alkali-aggregate reaction
ABS	acrylonitrile-butadiene-styrene
ACCA	alternating current attenuation
ACFM	alternating current field measurement
ACR	alkali-carbonate reaction
ACVG	alternating current voltage gradient
AE	acoustic emission
AEM	acoustic emission monitoring
AFCEN	Association française pour les règles de conception et de construction des matériels des chaudières électronucléaires
AMP	ageing management programme
AMR	ageing management review
APEC	area potential and earth current
API	American Petroleum Institute
ARV	air release valve
ASCE	American Society of Civil Engineers
ASM	American Society for Metals
ASME	American Society of Mechanical Engineers
ASNT	American Society for Non-destructive Testing
ASR	alkali–silica reaction
ASTM	American Society for Testing of Materials
AWWA	American Water Works Association
BEM	broadband electromagnetic method
BPIG	Buried Pipe Integrity Group
BWP	bar-wrapped pipe
CCTV	closed circuit television

CCW	component cooling water
CFRP	carbon fibre reinforced polymer
CIPP	cured in-place pipe
CIPS	close-interval potential survey
Cl-ESCC	chloride external stress corrosion cracking
СР	cathodic protection
СРР	Concrete Pressure Pipe
CPUG	Cathodic Protection Users Group
CS	carbon steel
CSA	Canadian Standards Association
CST	condensate storage and transfer
СТ	computed tomography
CTE	coal tar enamel
CUI	corrosion under insulation
CVCS	chemical and volume control system
DBA	design basis accident
DCP	double containment pipe
DCVG	direct current voltage gradient
DIN	Deutsches Institut für Normung e.V. (German Institute for Standardization)
ECA	eddy current array
ECDA	external corrosion direct assessment
ECP	embedded cylinder pipe
ECT	eddy current testing
EDF	Electricité de France
EDXS	energy dispersive X ray spectroscopy
EIM&T	examination, inspection, maintenance and testing
EM	electromagnetic

EMAT	electromagnetic acoustic transducer testing
EMT	electrical metallic tubing
EPRI	Electrical Power Research Institute
ESW	essential service water
FAC	flow accelerated corrosion
FBE	fusion bonded epoxy
FCA	future corrosion allowance
FEA	finite element analysis
FFS	fitness for service
FME	foreign material exclusion
FRP	fibre reinforced plastic
GALL	Generic Aging Lessons Learned
GFRP	glass-fibre reinforced plastic
GIS	geographic information system
GPR	ground penetrating radar
GPS	global positioning system
GRP	glass reinforced plastic
GWUT	guided wave ultrasonic testing
HDPE	high density polyethylene
HF	high frequency
HSLA	high strength low alloy (steel)
HX	heat exchanger
IASCC	irradiation assisted stress corrosion cracking
ICCP	impressed current cathodic protection
ICDA	internal corrosion direct assessment
IGALL	International Generic Ageing Lessons Learned
IGC	intergranular corrosion

IGSCC	intergranular stress corrosion cracking
IMC	inspection manual chapter
INPO	Institute of Nuclear Power Operations
LCP	lined cylinder pipe
LDI	liquid droplet impingement
LFET	low frequency electromagnetic technique
MFL	magnetic flux leakage
MIC	microbiologically influenced corrosion
MMO	mixed metal oxide
MT	magnetic particle testing
MTM	magnetic tomography method
MWM	meandering wire magnetometer
NACE	National Association of Corrosion Engineers (now NACE International)
NASSCO	National Association for Sewer Service Companies
NDE	non-destructive evaluation
NDE NDT	non-destructive evaluation non-destructive testing
NDE NDT NEI	non-destructive evaluation non-destructive testing Nuclear Energy Institute
NDE NDT NEI NFPA	non-destructive evaluation non-destructive testing Nuclear Energy Institute National Fire Protection Association
NDE NDT NEI NFPA NLPA	non-destructive evaluation non-destructive testing Nuclear Energy Institute National Fire Protection Association National Leak Protection Association
NDE NDT NEI NFPA NLPA NRC	non-destructive evaluation non-destructive testing Nuclear Energy Institute National Fire Protection Association National Leak Protection Association Nuclear Regulatory Commission
NDE NDT NEI NFPA NLPA NRC OPEX	non-destructive evaluation non-destructive testing Nuclear Energy Institute National Fire Protection Association National Leak Protection Association Nuclear Regulatory Commission operating experience
NDE NDT NEI NFPA NLPA NRC OPEX	non-destructive evaluation non-destructive testing Nuclear Energy Institute National Fire Protection Association National Leak Protection Association Nuclear Regulatory Commission operating experience
NDE NDT NEI NFPA NLPA NRC OPEX PAB	non-destructive evaluation non-destructive testing Nuclear Energy Institute National Fire Protection Association National Leak Protection Association Nuclear Regulatory Commission operating experience primary auxiliary building
NDE NDT NEI NFPA NLPA NRC OPEX PAB PB	non-destructive evaluation non-destructive testing Nuclear Energy Institute National Fire Protection Association National Leak Protection Association Nuclear Regulatory Commission operating experience primary auxiliary building polybutylene prestressed concrete cylinder pipe
NDE NDT NEI NEPA NIPA NRC OPEX PAB PCCP PCM	non-destructive evaluation non-destructive testing Nuclear Energy Institute National Fire Protection Association National Leak Protection Association Nuclear Regulatory Commission operating experience primary auxiliary building polybutylene prestressed concrete cylinder pipe pipeline current mapper
NDE NDT NEI NFPA NLPA NRC OPEX PAB PB PCCP PCM PDRI	non-destructive evaluation non-destructive testing Nuclear Energy Institute National Fire Protection Association National Leak Protection Association Nuclear Regulatory Commission operating experience primary auxiliary building polybutylene prestressed concrete cylinder pipe pipeline current mapper project definition rating index

PEC	pulsed eddy current
PEI	Petroleum Equipment Institute
PHWR	pressurized heavy water reactor
PIG	pipeline inspection gauge
POD	probability of detection
PP	polypropylene
PT	liquid penetrant testing
PVC	polyvinyl chloride
PWR	pressurized water reactor
PWROG	Pressurized Water Reactor Operators Group
PWSCC	primary water stress corrosion cracking
RCCP	reinforced concrete cylinder pipe
RCNP	reinforced concrete non-cylinder pipe
RCP	reinforced concrete pipe
RFEC	remote field eddy current
RFET	remote field electromagnetic technique
RFT	remote field testing
RFTC	remote field transformer coupling
RLCS	rubber lined carbon steel (pipe)
RT	radiographic testing
RTR	real time radiography
RTTM	real time transient model
SACP	sacrificial anode cathodic protection
SASW	spectral analysis of surface waves
SLOFEC	saturation low frequency eddy current
SCC	stress corrosion cracking
SCG	slow crack growth

SR	safety related
SSC	systems, structures and components
STI	Steel Tank Institute
SWP	steel water pipe
TC	transformer coupling
TGB	turbine generator building
TGSCC	transgranular stress corrosion cracking
TLAA	time limited ageing analysis
ULC	Underwriters' Laboratories of Canada
UST	underground storage tank
UT	ultrasonic testing
UV	ultraviolet
VT	visual testing
WRc	Water Research Centre

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CONTRIBUTORS TO DRAFTING AND REVIEW

Akimov, E.	Rosenergoatom, Russian Federation
Antaki, G.	Becht Engineering, United States of America
Arnold, S.	Fyfe Co., United States of America
Babics, P.	Hungarian Atomic Energy Authority, Hungary
Baines, K	Nuclear Decommissioning Authority, United Kingdom
Breon, L.	Electric Power Research Institute, United States of America
Crockett, H.	Altran Solutions, United States of America
Crolet, Y.	EDF — SEPTEN, France
Dóczi, M.	MVM Paks Nuclear Power Plant Ltd, Hungary
Eckert, T.	Electric Power Research Institute, United States of America
Eom, S.	Canadian Nuclear Safety Commission, Canada
Feldman, H.	Electric Power Research Institute, United States of America
Genov, D.	Kozloduy nuclear power plant Plc., Bulgaria
Holsten, W.	USNRC, United States of America
Kadenko, I.	Institute for Nuclear Research, Ukraine
Kenefick, S.	Electric Power Research Institute, United States of America
Keshavarez, A.	Ontario Power Generation, Canada
Kohn, P.	Duke Energy, United States of America
Kříž, V.	Rock Solid Group, Czech Republic
Lawson, K.	Mears Group, United States of America
Licina, G.	Structural Integrity Associates, Inc., United States of America
Lim, BT.,	KEPCO-ENC, Republic of Korea
Lupia, G.	Exelon Corp., United States of America
Markulin, K.	INETEC-Institute for Nuclear Technology, Croatia
McKenzie, D.	EDF Energy, United Kingdom
Mecado Vargas, J.	Laguna Verde nuclear power plant, Mexico
Moore, J.H.	International Atomic Energy Agency
Munson, D.	Electric Power Research Institute, United States of America
Ogundele, G.	Kinectrics, Canada
Ojdrovic, R.	Simpson Gumpertz & Heger, United States of America

Park, S.	KHNP, Republic of Korea
Petukhov, V.	Rosenergoatom, Russian Federation
Pinto, A.	Eletronuclear, Brazil
Quarry, M.	Electric Power Research Institute, United States of America
Robles, E.	Instituto Nacional de Investigaciones Nucleares, Mexico
Scott, D.	Electric Power Research Institute, United States of America
Smith, D.	Electric Power Research Institute, United States of America
Southard, R.	NACE International, United States of America
Stoeva, N.	J.D. Stevenson and Associates, Inc., United States of America
Summe, A.	Electric Power Research Institute, United States of America
Vavruška, J.	Rock Solid Group, Czech Republic
Zhang, G.	CNNP Nuclear Power Operation Management, Co. Ltd, China

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