API AUTHORIZED PIPING INSPECTOR

PREPARATION COURSE FOR CERTIFICATION EXAMINATION

2003

OUTLINE

SUBJECT : FAMILIARIZE CANDIDATES FOR THE CERTIFICATION EXAMINATION

OBJECTIVE : FAMILIAR CANDIDATES FOR THE CERTIFICATION TEST WITH TYPES AND FORMS OF INFORMATION IN WHICH THEY MUST KNOWLEDGEBLE

REFERENCES : BODY OF KNOWLEDGE, API PIPING INSPECTOR CERTIFICATION EXAMINATION. API 570, PIPING INSPECTION CODE

Forward

A. This edition supercedes all previous editions. Each edition, revision or addenda may be used beginning with the date of issuance. Effective 6 months after publication.

B. During the six month lag time between issuance and affectivity, the user must specify which edition/addenda is mandatory.

C. Use of API publications

   1. May be used by anyone desiring to do so.
   2. No warranties given
   3. Disclaims liability or responsibility for loss or damage.

D. Submit revisions, report, comments and request for interpretations to API.

SECTION 1- SCOPE
1.1 GENERAL APPLICATION

1.1.1. Coverage

Covers inspection, repair, alteration and relating procedures for metallic piping systems that have been in service.

1.1.2 Intent

- A. Developed for:
  - a. Petroleum refining industry.
  - b. Chemical process industries
- B. May be used:
  - a. Where practical, for any piping system
- C. Intended for use:
  - a. By organizations that maintain or have access to an authorized:
    1. Inspection agency.
    2. Repair organization
    3. Technically qualified piping engineers, inspectors and examiners (refer to Appendix A)

1.1.3 Limitations

- A. SHALL NOT be used as a substitute for the original construction requirements governing a piping system before it is placed in-service.
- B. SHALL NOT be used in conflict with any prevailing regulatory requirements

1.2 SPECIFIC APPLICATIONS

1.2.1 <u>Included Fluid Services.</u>

A. Raw, intermediate and finished petroleum products
B. Raw , intermediate and finished chemical products
C. Catalyst lines.
D. Hydrogen, natural gas, fuel gas and flare systems.
E. Sour water and hazardous waste streams above threshold limits, as defined in jurisdictional regulations.
F. Hazardous chemicals above threshold limits, as defined by jurisdictional regulations

1.2.2 <u>Excluded and Optional Piping Systems</u>

A. Fluid services that are excluded or optional the following:
1. Piping systems on movable structures covered by jurisdictional regulations, including piping systems on trucks, ships, barges and other mobile equipment.
2. Water (including fire protection systems), steam condensate, boiler feed water and Category D fluid services, as defined in ASME B31.3.
3. Internal piping or tubing of fired heaters and boilers, including tubes, tube headers, return bends, external crossovers and manifolds.
4. Pressure vessels, heaters, furnaces, heat exchangers and other fluid handling or processing equipment, including internal piping and connections for external piping.
5. Plumbing, sanitary sewers, process waste sewers and storm sewers.
6. Piping or tubing with an outside diameter not exceeding that of NPS ½”
7. Nonmetallic piping and polymeric or glass-lined piping

1.3 FITNESS FOR SERVICE

API 570 recognizes FFS concepts for evaluating degradation and references RP 579 for guidance when assessing various forms of degradation.

SECTION 3- DEFINITIONS

The API 570 candidate must know all terms and definitions. Some of the terms have been on the test, include:

3.1 Alterations
3.4 Authorized Inspection Agency
3.6 Auxiliary Piping
3.9 Dead legs
3.12 Examiner
3.13 Imperfections
3.16 Injection Point
3.31 Piping Circuit
3.33 Piping System
3.34 Primary Process Piping
3.37 Repair
3.38 Repair Organization
3.41 SBP
3.46 Test Point
3.47 TML

New terms that have recently been added are: material verification program, pre testing, fitness-for-service as assessment, Industry- Qualified UT Shear wave Examiner

SECTION 4- OWNER-USER INSPECTION ORGANIZATION

4.1 GENERAL

Owner – user of piping systems.

1.Exercise control of:
 a. Piping system inspection program
 b. Inspection frequencies
 c. Maintenance
2.Responsible for the function of an authorized inspection agency in accordance with API 570.
 The owner/user inspection organization shall control activities relating to:
 a. Relating of piping
 b. Repair of piping
 c. Alteration of piping

4.2 AUTORIZED PIPING INSPECTOR QUALIFICATION AND CERTIFICATION (SEE APPENDIX A)

A. Education and Experience.

1.ABS in engineering or technology plus one year of experience in the design, construction, repair, operation or inspection of piping
systems or supervision of piping inspection of piping systems or supervision of piping inspection.
2. A 2-year certificate or degree in engineering or technology plus 2 years of experience in the design, construction, repair, operation or inspection or inspection of piping systems or supervision of inspection of piping systems.
3. The equivalent of a high school education plus 3 years of experience in the design , construction, repair, inspection or operation of piping systems.
4. A minimum of five years of experience in the design, construction, repair, inspection or operation of piping systems or supervision of inspection.

Note: Whenever the term inspector is used in API 570, it refers to an Authorized Piping Inspector.

4.3 RESPONSIBILITIES

4.3.1 <u>Owner/User</u>
Responsible for developing, documenting, implementing executing and assessing piping inspection systems and procedures to meet this code. A mandatory QA program is required which <u>shall</u> include items a-o

4.3.2 <u>Piping Engineer.</u>
A. Responsible to owner-user
B. For activities involving design, engineering review, analysis or evaluation of piping systems covered by API 570.

43.3 <u>Repair Organization</u>
A. Responsible to owner-user.
B. Provides materials, equipment, quality control and workmanship necessary to maintain and repair the piping systems in accordance with the requirements of API 570.

4.3.4 <u>Inspector</u>
A. Responsible to owner-user for inspection, examination and testing are met.
B. Determines that the requirements of API 570 for inspection, examination and testing are met
C. May be assisted by other non-certified personnel. All examination results must be evaluated and accepted by the API 570 Inspector.

4.3.5 <u>Other Personnel</u>
A. Operating, maintenance or other personnel who have special knowledge or expertise related to particular piping systems
B. Responsible for promptly making the inspector or piping engineer aware of any unusual conditions that may develop.
C. Responsible for providing other assistance, where appropriate.

SECTION 5- INSPECTION AND TESTING PRACTICES

5.1 <u>Risk Based Inspection (RBI)</u>

Paragraph added in 1997 to specifically address RBI. Highlights to remember from this paragraph:

- <u>RBI</u> – Assessments include both likelihood and consequence of failure.
- <u>Likelihood</u> – Based on all forms of degradation and should be repeated if process changes are made. Material selection and piping design are important factors. History of piping very important!
- Each assessment should be tailored to the specific degradation that will occur, and should be modified (i.e. higher/lower risk factors) based on the consequence of the consequence of a failure of piping system.

5.2 <u>Preparation</u>

A. Safety precautions
  1.Because of products carried.
  2.Particularly dangerous when opened.
B. Safety procedures should be an integral part of:
  1. Segregating piping systems.
  2. Installing blanks (blinds)
  3. Testing tightness.
C. Safety precautions shall be taken before any piping system is opened and before some types of external
  inspection are performed.
D. In general, the section of piping to be opened should be isolated from all sources of harmful liquids, gases and vapors.
E. Before starting inspection:
  1. Obtain permission to work from operating personnel.
F. Wear protective equipment required by regulations or by owner-user.
G. NDT equipment is subject to safety requirements for electrical equipment.
H. General
  1. Inspector familiarize themselves with prior inspection results and repairs in the piping system being inspected.
  2. Inspectors should review history of individual piping systems before making any of the inspections required by API 570 (see Section 8 of RP 574 and RP 579 for overview of deterioration and failure modes)

5.3 INSPECTION FOR SPECIFIC TYPES OF CORROSION & CRACKING

Areas where owner-user should provide specific attention because they are susceptible to specific types and areas of deterioration:

1. Injection
2. Dead legs
3. Corrosion under insulation (cui)
4. Soil-to-air (S/A) interfaces
5. Service specific and localized corrosion
6. Erosion and corrosion/erosion
7. Environmental cracking
8. Corrosion beneath linings and deposits
9. Fatigue cracking
10. Creep cracking
11. Brittle fracture
12. Freeze damage

B. Also see RP 571 and 574 for further guidance

53.1 <u>Injection Points</u>

A. Injection points sometimes experience accelerate or localized corrosion from normal or abnormal operating conditions.
   1. May be treated as separate inspection circuits
   2. Inspect thoroughly and on a regular schedule

B. Recommended upstream limit of the injection point circuit:
   1. Minimum of 12"(305 mm) or 3 pipe diameters upstream of the injection point

C. Recommended downstream limit of the injection point circuit:
   1. Second change in flow direction past the injection point, or 25 feet (7.6 meters) beyond the first change in flow direction, whichever is less.

D. Selection of thickness measurement locations (TML's) in injection point circuits should be in accordance with the following:

1. Establish TML's on appropriate fittings within the injection point circuits.
2. Establish TML's on the pipe wall at the location of expected pipe wall impingement of injected fluid.
3. TML's may be required at intermediate locations along the longer straight piping within the injection point circuit
4. Establish TML's at both the upstream and downstream limits of the injection point circuit

E. Preferred methods of inspecting injection points are:

1. Radiography and/ or
2. Ultrasonic
3. Establish minimum thickness at each TML
4. Close gird ultrasonic measurements or scanning my be used, as long as temperature are appropriate

F. For some applications, piping spools may be removed to facilitate a visual inspection of the inside surface. Thickness measurements will still be required to determine the remaining thickness at all TML's within the injection point circuit.

G. During periodic scheduled inspections, more extensive inspection should be applied to an area beginning 12" (305 mm) upstream of the injection nozzle and continuing for at least ten pipe all TML's within the injection point circuit.

5.3.2 <u>Dead legs</u>

A. Corrosion rate in dead legs can vary from adjacent active piping.

1. Monitor wall thickness on selected dead legs in a system
   a. Stagnant end
   b. Connection to an active line
2. In hot piping
   a. High-point may corrode due to convective currents set up in dead leg
3. Dead legs should be removed if they serve no process purpose.

5.3.3 CORROSION UNDER INSULATION

A. External inspection
1. Review integrity of the insulation system for conditions that could lead to CUI
2. Check for signs of on going CUI.
3. Sources of moisture
   a. Rain
   b. Water leaks
   c. Condensation
   d. Deluge systems
4. Most common for of CUI is localized corrosion of carbon steel and stress corrosion cracking of austenitic stainless steels

B. CUI inspection programs may vary depending on the local climate.
1. Warmer, marine locations may require a very active program
2. Cooler, drier, mid-continent locations may need as extensive a program

5.3.3.1 <u>Insulated Piping Systems Susceptible to CUI</u>

A. Areas and types of piping systems more susceptible to CUI
1. Areas exposed to mist overspray from cooling water towers
2. Areas exposed to steam vents
3. Areas exposed to deluge systems
4. Areas subject to process spills, ingress of moisture, or acid vapors.
5. Carbon steel piping systems, including those insulate for personnel protection, operating between 25 degrees F and 250 degrees F. CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation.
6. Carbon steel piping systems that normally operate in-service above 250 degrees F, but are in intermittent service.
7. Dead legs and attachments that protrude from insulated piping and operate at a different temperature than the operating temperature of the active line.
8. Austenitic stainless steel piping systems operating between 150 and 400 F (subject to chloride stress corrosion cracking)
9. Vibrating piping systems that have a tendency to inflict damage to insulation jacketing – provides a path for water ingress.
10. Steam traced piping systems that may experience tracking leaks, especially a tubing fittings beneath insulation
11. Piping system with deteriorated coatings and/or wrappings.

5.3.3.2 COMMON LOCATIONS ON PIPING SYSTEMS SUSCEPTIBLE TO CUI

A. Specific locations for CUI.

1. All penetrations or breaches in the insulation jacketing systems, such as:
   a. Dead legs (vents, drain and other similar items)
   b. Pipe hangers and other supports
   c. Valves and fittings (irregular insulation surface)
   d. Bolted-on pipe shoes
   e. Steam tracer tubing penetrations.
2. Termination of insulation at flanges and other piping components
3. Damaged or missing insulation jacketing
4. Insulation jacketing seams located on the top of horizontal piping or improperly lapped or sealed insulation jacketing
5. Termination of insulation in a vertical pipe.
6. Caulking that has hardened, has separated or is missing
7. Bulges or staining of the insulation or jacketing system or missing bands
   (Bulges may indicate corrosion product buildup)
8. Low point s in piping systems that have a known breach in the insulation system, including low points in long unsupported piping runs.
9. Carbon or low-alloy steel flanges, bolting and other components under insulation in high-alloy piping systems.

5.3.4 SOIL-TO -AIR INTERFACE

A. Soil-to-air (S/A) for buried piping without adequate cathodic protection.
   1. Include in scheduled external piping inspections
   2. Inspect at grade for:
      a. Coating damage
      b. Bare pipe
      c. Pitting (include pit depth measurements.
   3. Significant corrosion found.
      a. check further to determine:
         1. thickness
         2. Whether further excavation required (is corrosion confined to the only the S/A interface)
         3. Make sure the area exposed by inspection is properly repaired-prevent future deterioration.
         4. If the buried piping has satisfactory cathodic protection, as determined by monitoring in Section 7 of API 570, excavation is required only if there is evidence of coating or wrapping damage.
         5. If piping is uncoated at grade, consideration should be given to excavating 6 to 12 inches deep to assess the potential for hidden damage.

B. Concrete-to-air and Asphalt-to-air interfaces.
   1. Look for evidence that the caulking or seal at the interface has deteriorated and allowed moisture ingress.
   2. If evidence exists that moisture has penetrated the interface seal, and the system is over 10 years old, inspection may be required beneath the surface before sealing the joint (Recommend if ANY doubt exist, INSPECT)

53.5 SERVICE-SPECIFIC AND LOCALIZED CORROSION

A. An effective inspection program includes the following three elements, which help identify the potential for service-specific and localized corrosion facilitate the selection of TML's.

1. An inspector with knowledge of the service and where corrosion is likely to occur.
2. Extensive use of nondestructive examination (NDE)
3. Communication from operating personnel when process upsets occur that may affect corrosion rates.

B. Examples of where service-specific and localized corrosion may occur

1. Downstream of injection points and upstream of product separators, such as in hydro process reactor effluent lines
2. Dew-point corrosion in condensing streams, such as over-head fractionation
3. Unanticipated acid or caustic carryover from processes into non-alloyed piping systems that are not post weld heat treated
4. Ammonium salt condensation locations in hydro process streams
5. Mixed-phase flow and turbulent areas in acidic systems
6. mixed grades of carbon steel piping in hot corrosive oil service (450 degrees F or higher) and sulfur content in the oil is greater than 0.5 percent by weight. Note that no silicon killed steel pipe (ASTM A-53 and API 5L) maycorrode at higher rates than silicon killed steel pip (ASTM A-106) – especially in high temperature sulfuric environments
7. Under deposit corrosion in slurries, crystallizing solutions, or coke producing fluids.
8. Chloride carryover in catalytic reformer regeneration systems
9. Hot-spot corrosion on piping with increased temperature, such as caustic in carbon steel, corrosion or stress corrosion cracking (SCC) can occur at hot spots that develop under low-flow conditions.

5.3.6 EROSION AND CORROSION/EROSION

A. Erosion
   1. Defined as the removal of surface material by the action of numerous individual impacts of solid or liquid particles
   2. Characterized by:
      a. Groove
      b. Rounded holes
      c. Waves and valleys in a directional pattern.
   3. Erosion damage occurs:
      a. In areas of turbulent flow:
         1. Such as at changes of direction in a piping system
         2. Downstream of control valves where vaporization may take place.

B. Corrosion/Erosion
   1. Significantly greater metal loss can be expected where combination of Corrosion and Erosion exist.
   2. Corrosion/Erosion occurs at high-velocity and high-turbulence areas.

C. Locations to inspect for Corrosion, Erosion and Corrosion/Erosion
   1. downstream of control valves, especially when flashing occurs.
   2. Downstream of orifices
   3. Downstream of pump discharges.
   4. At any point of flow direction change, such as the inside and outside radius of elbows.
   5. Downstream of piping configurations (such as weld, thermo wells, and flanges) that produce turbulence, particularly in velocity sensitive systems such as ammonium hydrosulfide and sulfuric acid systems.

D. Areas suspected of having localized corrosion/erosion should be inspected using appropriate NDE methods that will yield thickness data over a wide area, such as ultrasonic scanning, radiographic profile or eddy current.

5.3.7 ENVIRONMETAL CRACKING

A. Construction materials.
  1. Selected to resist various forms of SCC
  2. Some systems susceptible to environmental cracking due to:
    a. Upset process conditions
    b. CUI (Corrosion under insulation)
    c. Unanticipated condensation
    d. Exposure to wet hydrogen sulfide or carbonates.

B. Examples of environmental cracking:
  1. Chloride SCC of austenitic stainless steels due to moisture and chlorides under insulation, under deposits, under gaskets or in crevices.
  2. Polythionic acid SCC of sensitized austenitic alloy steels due to exposure to sulfide, moisture condensation or oxygen.
  3. Caustic SCC (sometimes known as caustic embitterment)
  4. Amine SCC in piping systems that are not stress relieved
  5. Carbonate SCC
  6. SCC in environments where wet hydrogen sulfide exists, such as systems containing sour water.
  7. Hydrogen blistering and hydrogen induced cracking (HIC) damage.

C. What to do if a piping circuit is suspected to have environmental cracking.
  1. Schedule supplemental inspections
    a. Surface NDE (PT,WFMT or UT)
  2. When possible, suspect pipe spools may be removed and examined internally

D. When environmental cracking is detect during internal inspection of pressure vessels and the piping is considered equally susceptible, the inspector should:
  1. Designate appropriate piping spools upstream and downstream of the pressure vessel for environmental cracking inspection

E. When the potential for environmental cracking is suspected in piping circuits:
  1. The inspector should schedule selected spools for inspection prior to an upcoming turnaround
  2. Inspection should provide information useful in forecast of turnaround maintenance

5.3.8 CORROSION BENEATH LININGS & DEPOSITS

A. Condition of external or internal coatings, refractory linings and corrosion resistant linings
   1. If in good condition, no reason to suspect deterioration of metal behind the lining
   2. No need to remove lining or parts of lining if the lining is good condition and no evidence of penetration or deterioration exists.

B. Reduction of corrosion resistant liner effectiveness.
   1. Effectiveness is reduced when the liner has:
      a. Breaks (cracks)
      b. Separation (disbonding)
      c. Holes
      d. Blisters (disbonding)
   2. If above conditions are noted, it may necessary to remove portions of the to investigate the conditions behind the liner.
   3. Ultrasonic inspection from the external surface can be used to measure wall thickness and detect separation, holes and blisters.

C. Reduction of refractory lining effectiveness.
   1. Effectiveness reduced when:
      a. Linings spall
      b. Linings crack
      c. Separation (disbonding)
      d. Bulging (also disbonding)
   2. If problems are noted, portions of the refractory may be removed to inspect the metal surface beneath the liner.
   3. UT inspection from the external metal surface can also reveal metal loss

D. Operating Deposits.
   1. Example: Coke
   2. Particularly important to determine whether there is active corrosion beneath the deposit.
   3. May require a thorough inspection in selected areas
      a. Larger lines should have the deposits removed in selected critical areas for spot examinations
      b. Smaller lines may require that selected spools be removed or that NDE methods, such as radiography, be performed in selected areas.

5.3.9 FATIGUE CRACKING

A. Results from excessive cyclic stresses that are often well below the static yield strength of the material.

B. Cyclic Stress causes:
1. Pressure
2. Mechanical
3. Thermal

C. Cyclic Stress may be from low-cycle or high-cycle fatigue.
1. low-cycle fatigue cracking
    a. Often related to the number of heat-up and cool-down cycles.
2. High-cycle fatigue cracking
    a. Usually related to excessive piping system vibration.
        1. Machines (pumps, compressors, etc)
        2. Flow-induced vibrations.

Note: Refer to Paragraph 5.5.4 of API 570 for vibrating pipe surveillance requirement and to paragraph 7.5 of API 570 for design requirements associated with vibrating-piping

D. Detection of fatigue cracking
1. Typically detected at points of high-stress concentrations.
    a. Branch connections.
2. Locations where metals having different coefficients of thermal expansion are joined by welding (thermal fatigue).

E. Preferred NDE methods of detecting fatigue cracking
1. PT, liquid-penetrate testing
2. MT, magnetic-particle testing
3. AE, acoustic emission also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test

F. Failure
1. Fatigue cracking is likely to cause piping failure before it is detected with any NDE method
2. Of the total number of fatigue cycles required to produce a failure, the vast majority are required to initiate a crack and relatively fewer cycles are required to propagate the crack to failure. Proper design and installation are necessary in order to prevent the initiation of fatigue cracking.

5.3.10 CREEP CRACKING

A. Creep is dependent on time, temperature and stress

1. May eventually occur at design conditions since some piping code allowable stresses are in the creep range
2. Cracking is accelerated by creep and fatigue interaction when operating conditions in the creep range are cyclic.
3. High stress areas should be checked
4. Excessive temperatures also cause mechanical property and microstructures changes in metal. These changes may permanently weaken the metal.
5. Actual or estimated levels of operating time, temperature and stress shall be used in evaluations. As an example of where creep cracking has been experienced in industry is in 1.25% CR-0.5 Molly Steels operating above 900 degrees F

B. NDE methods for determining creep

1. PT, liquid-penetrant testing
2. MT, magnetic-particle testing
3. UT, ultrasonic testing
4. RT, radiographic testing
5. In-situ metallographic
6. AE, acoustic emission testing, may also be used to detect the presence of cracks that are activated by test pressures or stresses generated during a test.

5.3.11 <u>Brittle fracture</u>

Brittle fracture can occur in carbon, low-alloy, and other ferritic steels at temperature at or below ambient temperatures. (Each metal has a transition temperature or a point where it ceases to be ductile and becomes brittle. The transition temperature varies markedly with differences in chemical composition, hardness or strength level, heat-treatment, microstructure, and steel-making practices. Steel with the proper combination of the above factor may have a transition temperature that is satisfactorily low. Most commonly used pressure vessel steel probably have transition temperatures between 0 degrees F and 100 degree F. However, special steels may have transition temperatures as high as 300 to 400 degrees F)

B. Most brittle fracture have occurred on the first application of a particular stress level, i.e., the first hydro test of overload. This is true unless a critical defect has been introduced during service.

1. The potential for brittle failure shall be considered when rehydrotesting.
2. Careful evaluation is necessary when pneumatically testing of equipment.
3. Evaluate also, when additional loads are added.
4. Evaluate low-alloy steels (2.25 CR-1 Mo) because they may be prone to brittle failure at much higher temperatures than ambient, i.e. 300+degrees F.

C. API RP 579 contain s procedures for assessing brittle fracture in piping.

5.3.12 <u>Freeze Damage</u>

A. Water and aqueous solutions in piping may freeze and cause failure because the expansion of the solutions.

1. Check piping that has frozen solutions in them before they thaw (usually occurs after an unexpectedly severe freeze). Checking for breaks before the thaw may provide a widow to temporarily prevent excess lose of fluid.
2. Low points, drip legs and dead legs of piping containing water should be carefully examined for damage.
3. It is obvious that draining of piping before a freeze takes place is a preventative measure. Steam or electric tracing of system subject to freeze damage is also an obvious precaution.

Note: See Section 6 of API 570 for frequency and extent of inspection.

5.4.1 INTERNAL VISUAL INSPECTION

A. Not normally performed on the majority of piping

B. Internal visual inspections may be done on the following:

1. Large-diameter transfer lines (lines large enough for human entry)
2. Ducts (large enough for human entry)
3. Catalyst lines (large enough for human entry)
4. Other large-diameter lines that permit human entry.
5. Inspection of the above lines are similar to pressure vessel inspections and should be conducted with methods and procedures similar to those listed in API 510.

C. Remote visual inspection techniques can be helpful when inspecting piping too small to enter.

D. Pipe also may be inspected internally when piping flanges are disconnected. Visual and NDE may be used.

E. Destructive testing such as removing a section of pipe and splitting it along its centerline may also be used.

5.4.2 <u>Thickness Measurement Inspection.</u>

A. Performed to determine the internal condition and remaining thickness of piping components.

B. Obtain when piping is in or out of operation

C. Thickness measurements made by the inspector or examiner

5.4.3 EXTERNAL VISUAL INSPECTION

A. Performed to :
1. Determine the condition of the outside of the piping, insulation, painting or coating system.
2. Check for signs of misalignment, vibration and leakage

B. Corrosion product buildup at pipe support contact areas indicate the need to lift the supports to inspect the pipe. Care should exercised if piping is in service.

C. In-service external piping inspection
1. Refer to API RP 574
2. See Appendix E in API 570 for a checklist to assist in the inspection

D. What to include in external visual inspections.
1. Check condition of piping hangers and supports.
   a. Cracked or broken hangers
   b. Bottoming out of spring supports
   c. Improper restraint conditions
   d. Improper restraint conditions
   e. Check vertical support dummy legs to confirm that they have not filled with water.
   f. Check horizontal support dummy legs to insure that they have not become moisture traps

E. Inspect bellows expansion joints.
1. Deformation
2. Misalignment
3. Displacements exceeding design.

F. Field modifications
1. Inspector should check for
   a. Field changes to piping
   b. Temporary repairs
   c. anything not recorded on piping drawings and/or inspection records.
2. Inspector should be alert to the presence of any components in the service that may be unsuitable for long term operation:

a. Improper flanges.
b. Temporary repairs such as clamps.
c. Modifications (flexible hoses)
d. Valves of improper specification
e. Threaded components that may be more easily removed and installed deserve particular attention because of their higher potential for installation of improper components.

G. Periodic inspections should be performed by the inspector (see Paragraph 4.3 of API 570)
1. Inspector also responsible for record keeping and repair inspection
2. Qualified operating or maintenance personnel also may conduct external inspections when acceptable to the inspector.
    a. In such cases, the persons conducting external piping inspections in a accordance with API 570 shall be qualified through an appropriate amount of training.

H. External inspections in addition to scheduled external inspections.
1. Any person who frequents the area should report deterioration of changes to the inspector.
2. See Appendix E of API 570 and Paragraph 8.2 of API RP 574 for examples.

5.4.4 <u>Supplemental Inspection</u>

A. Other inspections may be scheduled as appropriate or necessary. Examples of:
1. Radiography.
    a. Check fouling or internal plugging.
    b. Detect localized corrosion.
2. Thermograph
    a. Check for spots in refractory lined systems.
    b. Check for remote leak detection.
3. Acoustic emission.
    a. Leak detection.
4. Ultrasonic.
    a. Check for localized corrosion

5.5 THICKNESS MEASUREMENT LOCATIONS

5.5.1 <u>Thickness Measurement Locations.</u>

A. TML's, thickness measurement locations are specific areas along the piping circuit where inspections are to be made.
   1. Nature varies according to TML location in the piping system
      a. Are they associated with injection points, etc
   2. Selection of TML's shall consider the potential for localized corrosion and service-specific corrosion as described in Paragraph 3.2 of API 570.
      a. Type of deterioration.
      b. Number readings to be taken at the TML.

5.5.2 <u>TML Monitoring.</u>

A. Monitor each piping system by taking TML's.
   1. Requirement for number of TML's
      a. Circuit subject to higher corrosion rates.
      b. Circuit subject to localized corrosion.
   2. Distribute TML's appropriately throughout each piping circuit.
   3. Reduce or eliminate TML's on piping not subject to high or selective corrosion.
      a. Olefin plant cold side piping
      b. Anhydrous ammonia piping
      c. Clean no corrosive hydrocarbon products
      d. High-alloy piping for product purity.
   4. Where TML's are reduced or eliminated, persons knowledge in corrosion should be consulted.

B. Located Minimum thickness at TML's
   1. UT scanning
      a. Scan with UT to find minimum thickness. This consists of taking several "searching" thickness measurements at the TML.
      b. The thinnest reading or an average of several measurement readings taken within the area of a test point shall be recorded and used to calculate:
      aa. Corrosion Rates
      bb. Remaining Life
      cc. Next Inspection Date
   2. Radiography.
   3. Electromagnetic techniques also can be used to locate thinning areas, then use UT and/or RT.

C. Thickness measurements should include, where appropriate:
  1. Measurements at each of 4 quadrants on pipe and fittings
  2. Special attention should be given:
    a. Inside radius of elbows
    b. Out radius of elbows.
    c. Tees
  3. As a minimum, the thinnest reading and its location **<u>shall</u>** be recorded.

D. TML's should also be established:
  1. For areas with continuing CUI.
  2. For areas with corrosion at S/A interfaces.
  3. For areas with general, uniform corrosion
  4. Other locations of potential localized corrosion

E. Mark TML's on inspection drawings and on the system to allow repetitive measurements at the same TML's. This recording procedure provides data for more accurate corrosion rate determination.

5.5.3 <u>TML Selection</u>

A. Selection or Adjust of TML's
  1. Inspector should take into account:
    a. Patterns of corrosion expected
    b. Patters of corrosion experienced.
  2. Uniform corrosion processes common to refining and petrochemical units.
    a. Result in fairly constant rate of pipe wall reduction independent of location within the piping circuit, either axially or circumstantially. Examples:
      1. High temperature sulfur corrosion
      2. sour water corrosion
      3. both of the above must have velocities not so excessive as to cause local corrosion/erosion to ells, tees, etc.
      4. In the above situations, the number of TML's will be fewer than required to monitor circuits subject to more localized metal loss.
    b. In theory, a circuit subject of perfectly uniform corrosion could be adequately monitored with a single TML. In reality, corrosion is never truly uniform, so additional TML's may be required.
    c. Inspectors must use their knowledge (and that of others) of the process units to optimize TMI selection for each circuit.
    d. The effort of collecting data must be balanced with the benefits provided by the data.

Selection of TML’s for non-uniform corrosion systems:

A. More TML’s should be selected for the piping systems with the following characteristics:
1. Higher potential for creating a safety or environmental emergency in the event of a leak.
2. Higher expected or experienced corrosion rates
3. Higher potential for localized corrosion
4. More complexity in terms of fittings, branches, dead legs, injection points and other similar items.
5. Higher potential for CUI.

Selection of fewer TML’s.

A. Fewer TML’s can be selected for piping systems with following characteristics:
1. Low potential for creating a safety or enviromental emergency in the event of a leak
2. Relatively no corrosive system
3. long, straight run piping system

Eliminate TML’s

A. TML’s can be eliminate for piping systems with the following characteristics:
1. Extremely low potential for creating a safety or environmental emergency in the event of a leak.
2. No corrosive systems, as demonstrated by history or similar service.
3. Systems not subject to changes that could cause corrosion.

5.6 THICKNESS MEASUREMENT METHODS

A. UT measuring instruments.
   1. Usually most accurate means for installed pipe larger than NPS 1”

B. Radiographic profile techniques.
   1. Preferred for pipe of NPS 1” and smaller.
   2. Also used for locating areas to be measured
      a. Insulated systems.
      b. Where no uniform or localized corrosion is suspected
      c. UT can be used for further inspection.

C. After thickness readings are obtained on insulated piping, the insulation must be properly repaired
   1. Reduce potential for CUI

D. When corrosion in a piping system is no uniform or the remaining thickness is a approaching the minimum required thickness, additional thickness measuring may be required.

E. Temperature effect on UT measurements.
   1. Measurements above 150 degrees F.
      a. Instruments, complaints and procedures should be used that will result in accurate measurements at the higher temperatures.
      b. Adjust by the appropriate correction factors.

F. Possible sources of measurement inaccuracies and eliminate their occurrence. As a general rule, each of the NDE techniques will have practical limits with respect to accuracy. The following are factors that can contribute to reduced accuracy of UT measurements.
   1. Improper instrument calibration.
   2. External coatings or scale.
   3. Excessive surface roughness
   4. Excessive “rocking” of the probe (on curved surfaces)
   5. Subsurface material flaws, such as laminations.
   6. Temperature effects (at temperatures above 150 degrees F)
   7. Small flaw detector screens
   8. Thickness of less than 1/8” (for typical thickness gages)

G. No uniform corrosion

1. To determine the corrosion rate of no uniform corrosion, measurements on the thinnest point must be repeated as closely as possible to the same location.
2. Alternatively, the minimum reading or an average of several readings at a test point may be considered.

H. Out of service piping systems

1. Thickness measurements may be taken through openings using calipers
2. Calipers are useful in determining approximate thickness of castings, forgings and valve bodies.
3. Pit depth may also be determined through openings using calipers (internal and external) – also pit depth approximation from CUI.

I. Pit depth may also be determined the depth of localized metal loss (Pit depth)

5.7 <u>Pressure Testing of Piping Systems.</u>

A. Pressure test are not normally conducted as part of a routine inspection. (See 6.2.6 for pressure testing requirements)

1. Exceptions
   a. Requirements of USCG for over water piping
   b. Requirements of Local Jurisdictions.
   c. When specified by the inspector or piping engineer.
2. When conducted, pressure tests shall be performed in accordance with the requirements of ASTM B31.3.
   a. Additional considerations are found in API RP 574 and API RP 579
3. Lower pressure test, which are used only for tightness of piping systems, may be conducted at pressures designated by the owner-user.

B. Test medium

1. Should be water
   a. Unless there is the possibility of damage due to freezing.
   b. Unless there are other adverse effects of water on the piping system.
2. A suitable nontoxic liquid may be used.
   a. If the liquid is flammable, its flash point shall be at least 120 degrees F. or greater.
   b. Consideration shall be given to the effect of the test environment of the test fluid.

C. Piping fabricated of or having components of 300 series stainless steels.

1. Hydro test practice, with 250 ppm maximum chloride, sanitized with chlorine or ozone)
2. After completing testing:
   a. Drain thoroughly. Make sure high point vents are open
   b. Blow dry with air (Nitrogen or another inert gas may be used if proper safety precautions are observed)
3. If potable water is not used, or if immediate draining and drying is not possible, water having a very low chloride level, higher pH (> 10) and having inhibitor added, may be considered to reduce the risk of pitting and microbiologically induced corrosion.

D. Sensitized austenitic stainless steel piping subject to polythionic stress corrosion cracking consideration should be given to using an alkaline-water solution for testing. Refer to NACE RP0170.

E. If a pressure tests to be maintained for a period of time and the best fluid in the system is subject to thermal expansion, precautions shall be taken to avoid excessive pressures.

F. When a pressure test is required, it shall be conducted after an heat treatment.

G. Before applying a hydrostatic test to piping systems, consideration should be given to the supporting structure design.

H. Pneumatic pressure test

1. May be used when it is impractical to hydrostatically test due to:
   a. Temperature
   b. Structural
   c. Process Laminations.
2. Risks due to personnel and property shall be considered. As a **minimum**, the inspection precautions contained in ASME B31.3 shall be applied to any pneumatic testing.

I. Test pressure exceeding the pressure relief valve on piping system.

1. Remove the pressure relief valve
2. Blind or blank the pressure relief valve
3. An alternate is to use to use a test clamp to hold down the valve disk.
   a. Do not turn down the adjusting nut on the valve spring.
4. Other appurtenances that are incapable of withstanding the test pressure should be removed or blanked.
   a. Gage glasses
   b. Pressure gages
   c. Expansion joints
   d. Rupture disks.
5. Lines containing expansion joints that cannot be removed or isolated, may be tested at a reduced pressure in accordance with the principles of ASME B31.3
6. If block valves are used to isolate a piping system, caution should be used to not exceed the permissible seat pressure as described in ASME B16.34 or applicable valve manufacturer data.

J. Upon complementation of the pressure test, pressure relief devices of the proper setting and other appurtenances removed or made inoperable during the pressure test, shall be reinstalled or reactivated.

5.8 MATERIAL VERIFICATION & TRACEABILITY

A. Inspector must verify correct new alloy materials used for repairs or alterations, when the alloy material is required to maintain pressure containment. The alloy verification program should be consistent with API RP 578

B. Using risk-assessment procedures, this verification can be:
1. 100% of all materials, or;
2. sampling a percentage of the materials, or;
3. PMI testing in accordance with RP 578

C. Owner/shall assess whether inadvertent materials have been substituted in existing piping systems. Retroactive PMI testing may be required; discrepant conditions should be targeted for replacement and a schedule for replacement shall be established by the owner/user and inspector, in consultation with a corrosion specialist.

5.9 INSPECTION OF VALVES

A. Normally, thickness measurements are not routinely taken on valves in piping circuits
a. Body of valve normally thicker than other piping.

B. When valves are dismantled for servicing and repair, the shop should be attentive to any unusual corrosion patterns or thinning. If noted, this information should be reported to the inspector.

C. Valves exposed to steep temperature cycling (FCCU, CRU, Steam Cleaning) should be examined periodically for thermal fatigue cracking.

D. Gate valves known to be or suspected of being exposed to corrosion/erosion
1. Thickness readings should be taken between the sets-area of high turbulence and high stress.

E. Control Valves and other throttling valves, particularly in high pressure drop and slurry services, can be susceptible to localized corrosion/erosion of the body down stream of the orifice. If such metal loss is suspected, the valve should be removed from the line for internal inspection. The inside of the downstream mating flange and piping also should be inspected for local metal loss inside of the downstream mating API Standard 598.

5.10 INSPECTION OF WELDS IN-SERVICE.

A. Inspection for piping weld quality is normally accomplished as a part of the requirements for / new construction, repairs or alterations. However, welds are often inspected for corrosion as part of a radiographic profile inspection or as part of internal inspection.

B. When radiographic profile exams of in service piping welds reveal imperfections.
   1. Crack-like imperfections
      a. Inspect further with weld quality radiography and/or UT to assess the magnitude of the imperfection.
   2. Make an effort to determine whether crack-like imperfections are from original weld fabrication or may be from an environmental cracking mechanism.

C. Environmental cracking shall be assessed by the piping engineer.

D. If imperfections are from the original weld fabrication, inspection and/or engineering analysis is required to assess the impact of the weld quality on piping integrity. This analysis may consist of one or more the following:
   1. Inspector judgment
   2. Certified welding inspector judgment
   3. Piping engineer judgment
   4. Engineering fitness-for-service analysis.

E. Issues to consider when assessing the quality of existing welds include the following:
   1. Original fabrication inspection acceptance criteria.
   2. Extent, magnitude, and orientation of imperfections
   3. Length of time in-service
   4. Operating versus design conditions
   5. Presence of secondary piping stresses (residual and thermal)
   6. Potential for fatigue loads (mechanical and thermal)
   7. Primary or secondary piping system
   8. Potential for fatigue loads (mechanical and thermal)
   9. Potential for impact or transient loads.
   10. Weld hardness.

F. In many cases for in-service welds, it is not appropriate to use the random or radiography acceptance criteria for weld quality in ASME B31.3. These acceptance criteria are intended to apply to new construction on a sampling of welds, not just the welds examined , in order to assess the probable quality of all welds (or welders) in the system. Some welds may exist that will not meet these criteria but will still perform satisfactorily in-service after being hydro tested. This is especially true on small branch connections that are normally not examined during new construction.

G. The owner/user shall specify the use of industry-qualified UT shear wave operators for specific sizing of defects, fitness-for service evaluations and monitoring of know flaws. This requirement becomes effective 2 years after publication of the 2001 Addendum (2003)

5.10 INSPECTION OF FLANGED JOINTS.

A. Markings on a representative sample of newly installed fasteners and gaskets should be examined to determine whether they meet the material specification. The markings are identified in the applicable ASME and ASTM standards. Questionable fasteners should be verified or renewed

B. Fasteners should extend completely through their nuts. Any fasteners and gaskets should be examined to determine whether they meet the material specification. The marking are identified in the applicable ASME and ASTM standards. Questionable fasteners should be verified or renewed

C. If installed flanges are excessively bent, their markings and thickness should be checked against engineering requirements before taking corrective action.

D. Flange and valve fasteners should be examined visually for corrosion

E. Flanged and valve bonnet joints should be examined for evidence of leakage, such as stains, deposits, or drips. Process leaks onto flange and bonnet fasteners may result in corrosion or environmental cracking. This examination should include those flanges enclosed with flange or splash-and spray guards.

F. Flanged joints that have been clamped and pumped with sealant should be checked for leakage at the bolts. Fasteners subjected to such leakage may corrode or crack (caustic cracking, for example). If repumping is contemplated, affected fasteners should be renewed first.

G. Fasteners on instrumentation that are subject to process pressure and/or temperature should be included in the scope of these examinations.

H. See API RP 574 for guidance when flanged joints are opened.

SECTION 6- FREQUENCY & EXTENT OF INSPECTION

6.1 General

A. Two ways of establishing inspection inspection intervals of piping – Consequence of failure with time/condition based criteria in Para 6.2 or Risk Based Assessment, as stated in 5.1.

B. The owner/user may modify the classification system to provide a more elaborate means of assessing consequence (i.e. sub-classifications, additional classes etc.)

C. RBI assessment can be used to better define:

a. Most appropriate inspections based on expected forms of degradation
b. Optimal inspection frequency
c. Extent of inspection
d. Prevention or lowering the like hood or consequence of a failure.

D. **Important Paragraph to Learn!**

RBI can be used to increase or decrease maximum recommended inspection intervals in Table 6-1 or Table 6-2. However the RBI assessment must be conducted at intervals not exceeding Table 6-1 limits or more often if required by process changes, equipment, or consequence changes. RBI assessment shall be reviewed and approved by a Piping Engineer and API Inspector at intervals not to exceed Table 6-1 or sooner.

6.2 PIPING SERVICE CLASSES

A. Process Piping Classes
1. Categorize into different classes
   a. Allows extra inspection on piping systems with higher potential consequence if failure or loss of containment occurs.
2. Higher classified systems require more extensive inspection
   a. Inspection also required on shorter intervals
   b. Shorter intervals and more extensive inspections affirm integrity of system for continued safe operation
3. Classifications based on potential safety and environmental effect should a occur.

B. Responsibility
1. Owner/User **<u>shall</u>** maintain a record or process piping fluids handled, including their classifications.
   a. API RP 750 and NFPA 704 provide information on classifying piping systems according to the potential hazards of the process fluids they contain.

6.2.1 <u>Class 1</u>

A. Service with highest potential of resulting in an immediate emergency if a leak occurs.

B. Emergency may be:
1. Safety
2. Environmental

C. Examples are as follows:
1. Flammable services that may auto-refrigerate & lead to brittle fracture.
2. Pressurized services that may rapidly vaporize during release, creating vapors that may collect and form an explosive mixture, such as C2, C3 and C4 streams.
3. Hydrogen sulfide (greater than 3% weight) in a gaseous stream.
4. Anhydrous hydrogen chloride
5. Hydrofluoric acid
6. Piping over or adjacent to water and piping over public throughways. (Refer to DOT and USCG regulations for inspection of underwater piping)

6.2.2 CLASS 2

A. Service not included in other classes are in Class 2. This classification includes the majority of unit process piping and selected off-site piping.

B. Examples are as follows:

1. On-site hydrocarbon that will slowly vaporize during release
2. Hydrogen, fuel gas and natural gas
3. On-Site strong acids and caustics.

6.2.3 <u>Class 3</u>

A. Services that are flammable

1. Do not significantly vaporize when the leak
2. Not located in high-activity areas

B. Services that are potentially harmful to human tissue but are located in remote areas may be included in this class

C. Examples

1. On-Site hydrocarbons what will not significantly vaporize during release
2. Distillate and product lines to and from storage and loading
3. Off-Site acids and caustics.

6.3 INSPECTION INTERVALS.

A. Establish and maintain inspection interval using the following criteria.
  1. Corrosion rate and remaining life calculations
  2. Piping service classification
  3. Applicable jurisdictional requirements.
  4. Judgment of the inspector, piping engineer supervisor, or a corrosion specialist. Base on:
    a. Operating condition
    b. Previous inspection history
    c. Current inspection results
    d. Conditions that may warrant supplemental inspections covered in Paragraph 5.4.5

B. Extent of External and Cui Inspections
  1. Owner/user or the Inspector **SHALL** establish inspection intervals for thickness measurement and external visual inspections. Also, where applicable, for internal and supplemental inspections.

C. Thickness measurements should be scheduled based on the calculation of not more than half the remaining life determined from corrosion rates indicated in API 570, paragraph 7.1.1 or at the maximum intervals given in Table 6-1 of API 570. Corrosion rates should be calculated according to API 570, paragraph 7.13.

D. Table 6-1 of API recommends maximum inspection intervals for the 3 categories of piping services described in 6-2 of API 570, it recommends intervals for injection point and S/A interfaces.

E. Inspection intervals must be reviewed and adjusted as necessary after each inspection or significant change in operating conditions.
  1. Consider the following when establishing various inspection intervals
    a. General corrosion
    b. Localized corrosion
    c. Pitting
    d. environmental cracking
    e. Other forms of deterioration.

6.4 EXTENT OF EXTERNAL AND CUI INSPECTIONS

A. External inspections **<u>should</u>** be conducted at the maximum intervals listed in Table 6-1 of API 570 using the checklist in Appendix D of API 570. Bare pipe must be checked for the condition of coatings and possible corrosion or other deterioration.

B. Inspection for CUI

1. Conduct on all piping systems susceptible to CUI listed in API 570, paragraph 5.3.3.1. **<u>After the required external is done</u>**, additional CUI inspection is required on susceptible systems as follows:
2. Table 6-2.

	Amount of Cui Inspection at Areas of **Damaged Insulation** <u>(NDE or Insulation Removal)</u>	Amount of CUI Inspection **at Subject areas by NDE (within** <u>temperature ranges of 5.3.3.1, e,f,h)</u>
Class 1	75%	50%
Class 2	50%	33%
Class 3	25%	10%

3. RT Profile or insulation removal/Visual is normally required. Other NDE may be used.
4. Table 2 is a <u>target</u> for plants with no CUI history. Several factors affect like hood, including:

- Local climate
- Insulation quality
- Coating quality
- Service

5. If the plants <u>has</u> CUI experience, targets in Table 2 may be increased or decreased.

Note: An exact documentation system of CUI is not required (What a relief (!)

D. Piping systems that are known to have a remaining life of over 10 years or that are protected against external corrosion, need not have insulation removed for the periodic external inspection. However, the condition of the insulating system or the outer jacketing, such as the cold-box shell, should be observed periodically by operating or other personnel. If deterioration is noted, it should be reported to the inspector.

1. Examples:
   a. Piping systems insulated effectively to preclude the entrance of moisture.
   b. Jacketed cryogenic piping systems
   c. Piping systems installed in a cold box in which the atmosphere is purged with an inert gas.
   d. Piping systems in which the temperature being maintained is sufficiently high to preclude the presence of water.

6.5 <u>Extent of Thickness Measurement Inspection</u>

A. To satisfy inspection interval requirements, each thickness measurement inspection should obtain thickness readings on a representative sampling of TMLs on each circuit (refer to API 570 , paragraph 3.4)
   1. Representative sample should include:
      a. Data for all the various types of components and orientations (horizontal and vertical) found in each circuit.
      b. TMLs with the earliest renewal date as of the previous inspection
      c. The more TMLs measured for each circuit, the more accurately the next inspection date will be projected. Therefore, scheduled inspection of circuits should obtain as many measurement as necessary.

B. Extent of inspec tion for injection points is covered in paragraph 3.2.1 of API 570

6.6 Extent of Small-Bore, Auxiliary Piping and Threaded-Connections Inspections.

6.6.1 SMALL-BORE PIPING INSPECTION

A. Small-Bore Piping (SBP) that is primary process piping should be inspected in accordance with all the requirements of API 570

B. SBP that is secondary process piping has different minimum requirements depending upon service classification.

1. Class 1 secondary SBP shall be inspected to the same requirements as primary process piping.
2. Class 2 and Class 3 secondary SBP inspection is optional
3. SBP dead legs (such as level bridles) in Class 3 systems should be inspected where corrosion has been experienced or is anticipated.

6.6.2 <u>Auxiliary Piping Inspection</u>

A. Inspection of secondary auxiliary SBP associated with instruments and machinery is optional

B. Criteria to consider in determining whether auxiliary SBP will need inspection includes the following:

1. Classification
2. Potential for environmental or fatigue cracking
3. Potential for corrosion based on experience with adjacent primary systems.
4. Potential for CUI

6.6.3 <u>Threaded-Connections will be according to the requirements listed above for</u>

A. Inspection of threaded connections will be according to the requirements listed above for auxiliary SBP

B. When selecting TMLs on threaded connections, include only those that can be radio graphed during scheduled inspections.

C. Threaded connections associated with machinery and subject to fatigue damage be periodically assessed and considered for possible renewal with a thicker wall or upgrading to welded components.

1. The schedule for such renewal will depend on issues such as the following:
   a. Classification of piping
   b. Magnitude and frequency of vibration
   c. Amount of unsupported weight
   d. Current piping wall thickness
   e. Wheatear or not the system can be maintained on-stream.
   f. Corrosion rate
   g. Intermittent service.

SECTION 7- INSPECTION DATA EVALUATION,ANALYSIS AND RECORDING.

7.1 Corrosion Rate Determination

7.1.1 Remaining Life calculations

A. Calculate the remaining life of piping systems using this formula

$$\text{Remaining Life (years)} = \frac{t_{actual} - t_{required}}{\text{Corrosion Rate (inches/mm per year)}}$$

t actual = the actual minimum thickness in inches/mm, measured at the time of inspection as specified in API 570, paragraph 5.6

t required = the required thickness, in inches or mm, at the same location as the t actual measurement. Computed by design formulas before corrosion allowance and manufacturer's tolerance are added.

B. Long Term (LT) corrosion rate shall be calculated as the following:

$$\text{Corrosion rate (LT)} = \frac{t_{initial} - t_{actual}}{\text{Time (years) between the initial and actual inspections}}$$

t initial = the thickness, in inches, obtained during the initial installation of piping, or the commencement of a new corrosion rate environment.

t actual = same as above

C. Short term (ST) corrosion rate shall be calculated as follows:

$$\text{Corrosion rate (ST)} = \frac{t\ \text{previous} - t\ \text{actual}}{\text{Time (years) between the last and previous inspections}}$$

t previous = the thickness, in inches/mm, obtained during one or more previous inspections at the same location.

t actual = same as above

D. A statistical approach to assess corrosion may be used with the formulas above. Statistical analysis using "point" measurements should not be used on piping systems susceptible to unpredictable localized corrosion.

E. LT and ST corrosion rates should be compared to see which results in the shortest remaining life. (See paragraph 6.3 of API 570 for inspection interval determination) The Inspector, consulting with a corrosion specialist, shall select the most appropriate corrosion rate.

7.1.2 Newly Installed Piping Systems or Changes in Service.

A. One of the following methods shall be used to determine the probable rate of corrosion from which the remaining wall thickness ate the time of the next inspection can be estimated.

1. A corrosion rate for a piping circuit may be calculated from data collected by owner-user on piping systems in comparable service.
2. If data for the same or similar service are not available, a corrosion rate for a piping circuit may be estimated from the owner-user's experience or from published data on piping systems in comparable service.
3. If the probable corrosion rate cannot be determined by either method listed above (items 1 & 2), the initial thickness measurement determinations shall be made after no more that 3 months of service by using NDT. Corrosion monitoring devices, such as corrosion coupons or corrosion probes, may be useful in establishing the timing of these thickness measurements. Subsequent measurements shall be after appropriate intervals until the corrosion rate is established.

7.1.3 EXISTING PIPING SYSTEMS

A. Corrosion rates shall be calculated on either that an inaccurate rate of corrosion has been assumed, the rate to be used for the next period shall be adjusted to agree with the actual rate found.

7.2 Maximum Allowable Working Pressure Determination.

A. MAWP for the continued use of piping systems shall be established using the applicable code. Computations may be made for known materials if all the following essential details are known to comply with the principles of the applicable code:

1. Upper and/or lower temperature limits for specific materials.
2. Quality of materials and workmanship
3. Inspection requirements
4. Reinforcement of openings.
5. Any cyclical service requirements.

B. Unknown Materials

1. Assume the lowest grade material and joint efficiency in the applicable code and make calculations.
2. Use the actual thickness of the pipe wall as determined by inspection minus twice the estimated corrosion loss before the date of the next inspection for recalculating the MAWP.
3. Allowance shall be made for the other loadings in accordance with the applicable code.
4. The applicable code allowances for pressure and temperature variations from the MAWP are permitted provided all of the associated code criteria are satisfied.

C. Table 7 – 1 contains two examples of calculation of MAWP illustrating the use of the corrosion half-life concept.

Table 7 – 1 Calculations

Para 7.2 states that MAWP of existing pipe must be calculated using a wall thickness determined by inspection (ultrasonic) minus twice the estimated corrosion loss before the next inspection. able 7 – 1 provides examples of these computations.

Example # 1: An 18 NPS pipe is rated for 600 psig@ 500° F. The pipe is SA-106 (stress is 20,000 psi) and the thickness is 380”. If the pipe was checked 10 years before and was checked 10 years before and was found to observed corrosion rate will continue) ?

$$P = \frac{2x20{,}000x1x\,(.380 - 2x.060)}{18}$$

P = 577 psig

S= 20,000
E = 1
t = 380
D = 18

$$CR = \frac{.500 - .380}{10}$$

CR = .012”/year
5 yrs x 0.012”/yr = 0.060”
metal loss at next inspection + .060”

P = 577 psig

Example # 2: If the above pipe will not be inspected for 15 years, what will the MAWP be?

$$P = \frac{2x20{,}000x1x\,(.380 - 2x.18)}{18}$$

15 yrs x 0.012 “/yr = 018”

Note: API 570 Second Edition has included examples “ using the SI units”. Since ASME B31.3 (nor any of the documents we are given) do not list stress values or pipe dimensions in SI units, you should not overly concern yourself with this SI formula. Be aware that you could get a test question, but they will (more than likely) provide you all the units.

7.3 RETIREMENT THICKNESS DETERMINATION

A. The minimum required pipe wall retirement thickness, shall be equal to or greater than the minimum required thickness or retirement thickness:

B. Consideration of general and localized corrosion shall be used.

C. Piping stress analysis:

1. Identify the most highly stressed components in a piping system
2. Predict the thermal movement of the system when it is placed in operation
3. Information useful:
   a. Concentrate inspection efforts at locations prone fatigue damage from:
      1. Thermal expansion (heat-up and cool-down) cycles
      2. Creep damage in high-temperature piping
   b. Comparing predicted thermal movements with observed movements:
      1. Help ID the occurrence of unexpected operating conditions and deterioration of guides and supports.
   c. Consultation with the piping engineer may be necessary to explain observed deviations from the analysis predictions, particularly for complicated systems involving multiple supports and guides between end points.

D. Piping stress analysis also can be employed to help solve observed piping vibration problems

1. Natural frequencies in which a piping system will vibrate can be predicted by analysis
2. Effects of additional guiding can be evaluated to assess its ability to control vibration by machine rotational speed.
3. It is important to determine that guides added to control vibration do not adversely restrict thermal expansion.

7.6 REPORTING AND RECORDS FOR PIPING SYSTEM INSPECTION

A. Any significant increase in corrosion rates shall be reported to the owner-user for appropriate action

B. Owner-user shall maintain appropriate permanent and progressive records of each piping system covered by API 570. These records shall contain:

1. Piping system service
2. Classification
3. Identification numbers
4. Inspection intervals
5. Documents necessary to record:
   a. The name of the individual performing the testing
   b. The date of the testing
   c. The types of testing
   d. The results of thickness measurements and other tests, inspections, repairs (temporary and permanent), alterations or ratings
6. Design information and piping drawings may be included
7. Information on maintenance activities and events affecting piping system integrity also should be included.
8. The date and results of required external inspections
9. See API RP 574 for guidance on piping inspection records.

C. The use of a computer based system for storing, calculating and analyzing data should be considered in view of the volume of data that will be generated as part of a piping test-point program. Computer programs are particularly useful for:

1. Storing the actual thickness readings.
2. Calculating short and long term corrosion rates, retirement dates, MAWP and re inspection intervals on a test-point by test-point basis.
3. Highlighting areas of high corrosion rates , circuits overdue for inspection, circuit close to retirement thickness and other information.

D. Algorithms for the analysis of data from entire circuits also may be included in the program. Care should be taken to ensure that the statistical treatment of circuit data results in predictions that accurately reflect the actual condition of the piping circuit.

SECTION 8- REPAIRS, ALTERATIONS & RERATING OF RERATING OF PIPING SYSTEMS

8.1 <u>Repairs and Alterations</u>

A. The principles of ASME B31.3 or the code to which the piping system was built shall be followed.

8.1.1 Authorization

A. All repair and alteration work must be done by a repair organization as defined in the Glossary of API 570 and must be authorized by the inspector prior to its commencement.

B. Authorization for alteration work to a piping system may not be given without prior consultation with and approval by, the piping engineer.

C. The inspector will designate any inspection hold points required during the repair or alteration sequence

1. Inspector may give prior general authorization for limited or routine repairs and procedures, provided the inspector is satisfied with the competency of the repair organization.

8.1.2 <u>Approval</u>

A. All proposed methods of design, execution, materials, welding procedures, examinations & testing must be approved by the inspector or by the piping engineer, as appropriate

B. Owner –User approval of on stream welding is required

C. Welding repairs of cracks that occurred in-service should not be attempted without prior consultation with the piping engineer in order to identify and correct the cause of the cracking. Examples are cracks suspected of being caused by vibration, thermal cycling, thermal expansion problems and environmental cracking.

D. The inspector shall approve all repair and alteration work at designed hold points and after the repairs and alterations have been satisfactorily completed in cycling, thermal expansion problems and alteration have been satisfactorily completed in accordance with the requirements of API 570.

8.1.3 <u>Welding Repairs (Including On- Stream)</u>

8.1.3.1 Temporary Repairs

A. For temporary repairs, including on-stream, a full encirclement welded split sleeve or box-type enclosure designed by the piping engineer may be applied over the damaged or corroded area.

1. Longitudinal cracks **<u>SHALL NOT</u>** be repaired in this manner unless the piping engineer has determined that cracks would not be expected to propagate from under the sleeve. In some cases, the piping engineer will need to consult with a fracture analyst

B. If the repair area is localized, e.g., pitting or pinholes and the specified minimum yield strength (SMYS) of the pipe is not be expected to propagate from under the sleeve. In some cases, the piping engineer will need to consult with a fracture analyst.

C. For minor leaks, properly designed enclosures may be welded over the leak while the piping system is in service, provided the inspector is satisfied that adequate thickness remains in the vicinity of the weld and the piping component can withstand welding without the likelihood of further material damage, such as from as from caustic service.

D. Temporary repairs should be removed and replaced with a suitable permanent repair at the next available maintenance opportunity. Temporary repairs may remain in place of a longer period of time only if approved and documented by the piping engineer.

8.1.3.2 PERMANENT REPAIRS

A. Repairs to defects found in piping components may be made by preparing a welding groove that completely removes the defect and then filing the groove with weld metal deposited in accordance with paragraph 8.2 of API 570

B. Corroded areas may be restored with weld metal deposit in accordance with paragraph 8.2 of API 570. Surface irregularities and contamination shall be removed before welding. Appropriate NDE methods shall be applied after completion of the weld.

C. If it is feasible to take the piping system out service, the defective area may be removed by cutting out a cylindrical section and replacing it with a piping component that meets the applicable code.

D. Insert patches (flush patches) may be used to repair damaged or corroded areas if the following requirements are met::

1. Full-penetration groove welds are provided
2. For Class 1 & 2 piping systems, the welds shall be 100% radio graphed or UT'd using NDE procedures that are approved by the engineer
3. Patches may be any shape but shall have rounded corners (1" minimum radii)

8.1.4 <u>No welding Repairs (On-Stream)</u>

A. Temporary repairs of locally thinned sections or circumferential linear defects may be made on-stream by installing a properly designed and fabricated bolted leak clamp. The design shall include control of axial thrust loads if the piping component being clamped is (or may become) component also shall be considered.

B. During turnarounds or other appropriate opportunities, temporary leak sealing and leak dissipating devices, including valves, **<u>shall</u>** be removed and appropriate actions taken to restore the original integrity of the piping system. The inspector and/or piping engineer shall be involved in determining repair methods and procedures.

C. Procedures that include leak sealing fluids ("pumping") for process piping should be reviewed for acceptance by the inspector or piping engineer. The review should take into consideration:

1. The compatibility of the sealant with the leaking material
2. The pumping pressure on the clamp (especially when repumping)
3. The risk of sealant affecting downstream flow meter, relief valves or machinery.
4. The risk of subsequent leakage at bolt threads causing corrosion or stress corrosion cracking of bolts.
5. The number of times the seal area is repumped.

8.2 WELDING AND HOT TAPPING

A. All repair and alteration welding shall be done in accordance with the principles of ASME B31.3 or the code to which the piping system was built.

B. Any welding conducted on piping components in operation must be done in accordance with API Publ.2201. The inspector shall use as a minimum the "Suggested Hot Tap Checklist" contained in API Publ.2201 for hot tapping performed on piping components.

A. The repair organization shall maintain records of welding procedures and welder performance qualifications. These records shall be available to the inspector prior to the start of welding.

8.2.2 <u>Preheating and Post weld Heat Treatment</u>.

8.2.2.1 <u>Preheat</u>

A. Preheat temperature used in making welding repairs shall be in accordance with applicable code and qualified welding procedure. Exceptions for temporary repairs must be approved by the piping engineer.

B. Local PWHT may be subsisted for 360-degree banding on local repairs on all materials, provided the following precautions and requirements and requirements are applied.

1. The application is reviewed and a procedure is developed by the piping engineer.
2. In evaluating the suitability of a procedure, consideration shall be given to applicable factors, such as base metal thickness, thermal gradients, material property as, changes resulting from PWHT, the need for full-penetration welds and surface and volumetric examinations after PWHT. Additionally, the overall and local strains and distortions resulting from the heating of a local restrained area of the piping wall shall be considered in developing and evaluating PWHT procedures.
3. A preheat of 300 degrees F or higher as specified by specific welding procedures, is maintained while welding
4. The required PWHT temperature shall be maintained for a distance of not less than two times the base metal thickness measured from the weld. The PWHT temperature shall be monitored by a suitable number of thermocouples (a minimum of two) based on the size and shape of the area being heat treated.
5. Controlled heat also shall be applied to any branch connection or the attachment within the PWHT area.
6. The PWHT is performed for code compliance and not for environmental cracking resistance

8.2.3 DESIGN

A. Butt joints shall be full-penetration groove welds

B. Piping components shall be replaced when repair is likely to be inadequate. Now connections and replacements shall be designed and fabricated according to the principles of the applicable code. The design of temporary enclosures and repairs shall be approved by the piping engineer.

C. New connections may be installed on piping systems provided the design, location and method of attachment conform to the principles of the applicable code.

D. Fillet welded patches require special design considerations, especially relating to weld-joint efficiency and crevice corrosion. Fillet welded patches shall be designed by the piping engineer.

A patch may be applied to the external surfaces of piping, provided it is in accordance with paragraph 8.13 of API 570 and meets either of the following requirements:

1. The proposed patch provides design strength equivalent to a reinforced opening designed according to the applicable code.
2. The proposed patch is designed to absorb the membrane strain of the part in a manner that is in accordance with the principles of the applicable code, if the following criteria are met:
   a. The allowable membrane stress is not exceeded in the piping part or the patch
   b. The strain in the patch does not result in fillet weld stress exceeding allowable stresses for such welds.
   c. An overlay patch shall have rounded corners (see Appendix C of API 570)

8.2.4 <u>Materials</u>

A. The materials used in making repairs or alterations shall be of known wed able quality, shall conform to the applicable code and shall be compatible with the original material. For material verification requirements, see paragraph 5.8 of API 570

8.2.5 <u>Pressure Testing</u>

A. Acceptance of a welded repair or alteration shall include NDE in accordance with the applicable code and the owner-user specification, unless otherwise specified in API 570.

8.2.6 PRESSURE TESTING

A. After welding is completed a pressure test in accordance with paragraph 5.7 of API 270 shall be performed if practical and deemed necessary by the inspector. Pressure tests are normally required after alterations and major repairs.

1. When a pressure test is not necessary or practical, NDE shall be utilized in lieu of a pressure test.
2. Substituting special procedures for a pressure test after an alteration or repair may be done only after consultation with the inspector and the piping engineer.

B. When it is not practical to perform a pressure test of a final closure weld that a new or replacement section of piping to an existing system, all of the following requirements shall be satisfied:

1. The new or replacement piping is pressure tested.
2. The closure weld is a full-penetration butt weld neck flange and standard piping component or straight sections of pipe of equal diameter and thickness, axially aligned (not miter cut) , and of equivalent materials. Alternative are:
   a. SOF's for flange class 150 up to 500°F
   b. Socket weld flanges or unions, NPS 2 or less and class 150 up to 500°F (Space must be used to ensure 1/16" gap)
   c. Any final closure butt weld shall be 100% radiographic quality: or angle-beam ultrasonic flaw detection may be used, provided the appropriate acceptance criteria have been established.
   d. MT or PT shall be performed on the root pass and the completed weld on butt welds. Fillet welds must have PT/MT on final welds.

C. The owner/user must use industry-qualified shear wave examiners for closure welds that have not been pressure tested and weld repairs. This becomes a requirement in 2003 (2 years after 2001 Addendum)

8.3 RERATING

A. <u>Rerating piping systems by changing the temperature rating or the MAWP may be done only after all of the following requirements have been met.</u>

1. Calculations are performed by the piping engineer or the inspector
2. All reratings shall be established in accordance with the requirements of the code to which the piping system was built or by computation using the appropriate methods in the latest edition of the applicable code.
3. Current inspection records verify that the piping system is satisfactory for the proposed service conditions and that the appropriate corrosion allowance is provided.
4. Rerated piping systems shall be leak tested in accordance with the code to which the piping system was built or the latest edition of the applicable code for the new service conditions, unless documented records indicate a previous leak test was performed at greater than or equal to the test pressure for the test pressure for the new condition. An increase in the rating temperature that does not affect allowable stress does not require a leak test.
5. The piping system is checked to affirm that the required pressure relieving devices are present, are set at the appropriate pressure, and have the appropriate capacity at set pressure
6. The piping system rerating is acceptable to the inspector or piping engineer
7. All piping components in the system (such as valves, flanges, bolts, gaskets, packing and expansion joints) are adequate for the new combination of pressure and temperature
8. Piping flexibility is adequate for design temperature changes.
9. Appropriate engineering records are updated
10. A decrease in minimum operating temperature is justified by impact test results, if required by the applicable code

SECTION 9- INSPECTION OF BURIED PIPING

Inspection of buried process piping (not regulated by DOT) is different from other process piping inspection because significant external deterioration can be caused by corrosive soil conditions. Since the inspection is hindered by the inaccessibility of the affected areas of the piping, the inspection of buried piping is treated in a separate section of API 570. Important, no mandatory references for underground piping inspection are the following NACE documents: RP0169, RP0275, and Section 9 of API RP 651.

9.1 Types and methods of Inspection

9.1.1 Above-Grade Visual Surveillance

A. Following are indicators of leaks in buried piping:
1. Change in surface contour of the ground.
2. Discoloration of the soil
3. Softening of paving asphalt
4. Pool formation
5. Bubbling water puddles
6. Noticeable odor
7. Freezing of the ground

9.1.2 Close-Interval Potential Survey

A. Close-interval survey at ground level over buried pipe can be used to locate active corrosion points on the pipe's surface.

B. Corrosion cells can form on both bare and coated pipe where the bare steel contacts the soil
1. Potential at areas of corrosion is measurably different from adjacent areas.
2. Location of active corrosion can be determined by this survey technique.

9.1.3 PIPE COATING HOLIDAY SURVEY

A. Survey to locate coating defects on buried coated pipes.
   1. Use on newly constructed pipe to ensure coating defects on buried coated pipes.
   2. Use on buried pipe that has been in service for a long period

B. Survey data gives information on effectiveness of coating and rate of coating deterioration.
   1. information used for:
      a. Predicting corrosion activity in a specific area
      b. Forecasting replacement of the coating

9.1.4 Soil Resistively

A. Corrosion of bare or poorly coated piping is often caused by a mixture of different soils in contact with the pipe surface.
   1. Corrosiveness of soil determined by measurement of soil resistively.
      a. Lower levels of resistively are relatively more corrosive than higher levels (especially in areas where pipe is exposed to significant changes in soil resistively)

B. Measurements of soil resistively should be performed using the Werner Four-pin Method in accordance with ASTM G57. In cases of parallel pipes or in areas of intersection pipelines, it may be necessary to use the Single-Pin Method to accurately measure the soil resistively. For measuring resistively of soil samples from auger holes or excavations, a soil box serves as a convenient means for obtaining accurate results.

C. The depth of the piping shall be considered in selecting the method to be used and the location of samples.
   1. Trained person used to evaluate the results.

9.1.5 Cathodic Protection Monitoring.

A. Monitor catholically protected pipe.
   1. Insure adequate levels of protection
   2. Periodic measurements and analysis of potentials should components, such as impressed current rectifiers is required to ensure reliability.
   3. More frequent monitoring of cathodic protection components, such as impressed current rectifiers is required to ensure reliability.

B. Use NACE RP0169 and Section 9 of API RP 651 for guidance to inspecting and maintaining cathodic protection systems of buried pipe.

9.1.6 INSPECTION METHODS

A. Inspection methods available
1. Intelligent pigging. Involves the movement of a device through the pipe while in or out of service. Several types of devices are available.
    a. Line must be free of restrictions
    b. Five diameter bends are usually required
    c. Line must have facilities to launch and retrieve the pig.

2. Video cameras
    a. Insert camera into pipe
    b. Provide visual view of interior of pipe

3. Excavation
    a. Unearth the pipe
    b. Visually inspect the external condition of the piping
    c. Take UT measurements like you would for above ground pipe.
    d. Radiographs also can be used
    e. Do not damage coating of pipe when it is unearthed-remove last few inches of soil manually
    f. Follow OSHA regulations for shoring of trenches.

9.2 Frequency and Extent of Inspection

9.2.1 Above-Grade Visual Surveillance

A. Owner-user, at approximately 6 month intervals, survey the surface conditions on and adjacent to each pipe line path.

9.2.2 Pipe-To-Soil Potential Survey

A. Cathodically protected pipe – Conduct survey at 5-year intervals

B. No cathodic protection
1. Pipe-to-soil potential survey should be made
2. Excavate at sites where active corrosion cells are indicated or located
3. Check areas where leaks have occurred before

9.2.3 <u>Pipe Coating Holiday Survey.</u>

A. Frequency of pipe coating holiday surveys is usually based on indications that other forms of corrosion control are ineffective.
   1. Example: A coated pipe where there is gradual loss of cathodic protection protection potentials or an external corrosion leak occurs at a coating defect, a pipe coating holiday survey may be used to evaluate the coating.

9.2.4 <u>Soil Corrosively</u>

A. Buried pipe in length greater than 100 feet and not cathodically protected.
   1. Evaluate soil corrosively every 5 years
   2. Soil resistively measurements may be used for relative classification of the soil corrosively
   3. Additional factors that warrant consideration:
      a. Change in soil chemistry
      b. Analyses of the polarization resistance of the soil and piping interface.

9.2.5 <u>Cathodic Protection</u>

A. Monitor asp per Section 10 of NACE RP0169 or Section 9 or API RP 651

9.2.6 <u>External and Internal inspection Intervals</u>

A. Internal corrosion of buried pipe suspected
   1. adjust inspection accordingly
   2. Inspector should be aware of accelerated corrosion, e.g., dead legs.

B. Determine external condition of buried pipe.
   1. Pig
   2. Excavate

C. Pipe inspected by excavation
   1. inspect lengths of 6 to 8 feet
   2. Inspect one or more locations at points susceptible to corrosion
   3. Inspect full circumference.

D. Pipe inspected by excavation

1. If excavation reveals damaged coating, continue excavation until good coating is reached.
2. Check wall thickness of pipe. If the average wall thickness is at or below retirement thickness, repair or replace pipe.

E. Pipe contained inside a pipe casing

1. Check condition of the casing
   a. Check to see if water or soil is present in the casing
2. Inspector should verify the following:
   a. Both ends of the casing extend beyond the ground line
   b. The ends of the casing are sealed if the casing is not self-draining
   c. The pressure carrying pipe is properly coated and wrapped.

9.2.7 <u>Leak Testing Intervals</u>.

A. An alternate or supplement to inspection of buried pipe is leak testing with liquid at pressure at least 10% greater than maximum operating pressure at intervals ½ the length of those s shown in Table 9 – 1 of API 570. The leak test should be maintained for a period of 8 hours. 4 hours after the initial pressurization of the piping system, the pressure source. If during the remainder of the test period, the pressure decreases more than 5% the piping should be visually inspected externally and/or inspected internally to find the leak and assess the extent of corrosion. Sonic measurements may be helpful in locating leaks.

B. Survey buried pipe for integrity by performing a leak using temperature – corrected volume or pressure test methods. Another method typically involves acoustic emission or pressurizing the line with a tracer gas (such as helium or sulfur hexafluoride), and checking the area above the buried with a detector.

If a gas tracer is used, suitability for mixing with the product must be assured.

9.3 REPAIRS TO COATINGS

A. Any coating removed for inspection shall be inspected appropriately and renewed or repaired as necessary.

B. For coating repairs the inspector should be assured that the coating meets the following criteria:
1. It has sufficient adhesion to the pipe to prevent under film migration of moisture.
2. It is sufficiently ductile to resist cracking
3. It is free of voids and gaps in the coating (holidays)
4. It has sufficient strength to resist damage due to handling and soil stress.
5. It can support any supplemental cathodic protection.

C. Coating repairs may be tested using a high voltage holiday detector. The detector voltage shall be adjusted to the appropriate value for the coating material and thickness. Any holidays foun shall be repaired and retested.

9.3.2 <u>Clamp Repairs</u>

A. Pipe leaks clamped and reburied
1. Log location of clamp on inspection records.
2. Surface mark if possible
3. Marker and record shall note date of installation and information on its location.
4. **<u>ALL</u>** clamps shall be considered temporary. The piping should be permanently repaired at the first opportunity.

9.3.3 <u>Welded Repairs</u> – Make in accordance with paragraph 8.2 of API 570

9.4 <u>Records</u>

A. Records systems for buried piping should be maintained in accordance with paragraph 7.6 of API 570.

B. A record of the location and date of installation of temporary clamps shall be maintained.

REVIEW APPENDICES

Appendix A – See review of 4.1 and:

- API is the Certifying Agent
- Recertification every 3 years
- "actively engaged" means at least 20% of time is spent performing or supervising inspection activities.

Appendix B – Review procedure for submittal of interpretation

Appendix C – Examples of repairs (a poorly written section in our opinion)

C-1 –

- GMAW or SMAW only
- Below 50°F –L..H welding rod only on C.S materials
- Below 32°F – L.H welding rod only on all materials
- When L.H rod is used on circ. Welds – uphill only
- Diameter of rods on circ. Welds – 5/32" max.
- Diameter of rods on long welds – 3/16" max
- Longitudinal weld – backing tape used, unless checked with UT to confirm acceptable thickness

C-2 – Small patches (see Figure C-2)

- Diameter rods – 5/32" max. L.H below 32°F
- Welding of L.H rods should be avoided
- Patches greater than ½ D should be full encirclement sleeve.

API 570 – PRACTICE QUESTIONS
CLOSED BOOK

1. API 570 covers inspection, repair, alteration and relating procedures for metallic piping systems that ____________________

a. Are being fabricated
b. Does not fall under ASTM B31.3
c. Have been in-service
d. Has not been tested

2. API 570 was developed for the petroleum refining and chemical process industries

a. It shall be used for all piping systems
b. It may be used, where practical, for any piping system
c. It can be used, where necessary, for steam piping
d. It may not be used unless agreed to by all parties

3. API 570 _________________ be used as a substitute for the original construction requirements governing a piping system before in-service.

a. Shall not
b. Should
c. May
d. Can

4. API 570 applies to piping systems for process fluids, hydrocarbons and similar flammable or toxic fluid services. Which of the following services is not specially applicable?

a. Raw, intermediate and finished petroleum products
b. Water, steam condensate, boiler feed water
c. Raw, intermediate and finished chemical products
d. Hydrogen, natural gas, fuel gas and flare systems

5. Some of the classes of piping systems that are excluded or optional for coverage under API 570 are listed below. Which one is a mandatory included class?

a. water
b. Catalyst lines
c. Steam
d. Boiler feed water

6. The __________ shall be responsible to the owner-user for determining that the requirements of API 570 for inspection, examination and testing are met.

a. Piping Engineer
b. Inspector
c. Repair Organization
d. Operating Personnel

7. Who is responsible for the control of piping system inspection programs, inspection frequencies and maintenance of piping?

a. Authorized Piping Inspector
b. Owner-User
c. Jurisdiction
d. Contractor

8. An Authorized Piping Inspector shall have the following qualifications. Pick the one that does not belong in this list.

a. Four years of experience inspecting in-service piping systems
b. High school education plus 3 years of experience in the design, construction, repair, operation or inspection of piping systems.
c. Two year certificate in engineering or technology plus 2 years of experience in the design, construction, repair, operation or inspection of piping systems.
d. Degree in engineering plus one year experience in the design, construction, repair, operation or inspection of piping systems.

9. Risk Based Inspection include which of the following:

a. Likelihood assessment
b. Consequence analysis
c. Operating and Inspection histories
d. All of the above

10. An RBI assessment can be used to alter the inspection strategy provided:

a. The degradation methods are identified
b. The RBI is fully documented
c. A third party conducts the RBI
d. Both A & B above

11. Which one of the following is not a specific type or an area of deterioration?

a. Rectifier performance
b. Injection points
c. Dead legs
d. Environmental cracking

12. Injection points subject to accelerated or localized corrosion may be treated as ______________.

a. The focal point of an inspection circuit
b. Separate inspection circuits
c. Piping that must be renewed on a regular schedule
d. Locations where corrosion inhibitors must be used

13. The recommended downstream limit of inspection of an injection point is a minimum of:

a. 12 feet or 3 lengths whichever is smaller
b. 12 inches or 3 pipe diameters whichever is smaller
c. 12 inches or 3 pipe diameters whichever is greater
d. 12 feet or 3 pipe lengths whichever is greater

14. The recommended downstream limit of inspection of an injection point is a minimum of:

a. Second change in flow direction past the injection point, or 25 feet beyond the first change in flow direction whichever is less.
b. Second change in flow direction past the injection point, or 25 feet beyond the first change in flow direction whichever is greater
c. Second change in flow direction past the injection point, or 25 inches beyond the first change in flow direction whichever is less.
d. Second change in flow direction past the injection point, or 25 inches beyond the first change in flow direction whichever is greater.

15. Select thickness measurement locations (TMLs) within injection point circuits subject to localized corrosion according to the following guidelines. Select the one that **does not** belong.

a. Establish TMLs on appropriate fittings within the injection point circuit
b. Establish at least one TML at a location at least 25 feet beyond the downstream limit of the injection point
c. Establish TMLs on pipe wall at the location of expected pipe wall impingement or injected fluid.
d. Establish TMLs at both the upstream limits of the injection point circuit.

16. What are the preferred methods of inspecting injection points?

a. Radiography and /or ultrasonics
b. Hammer test and /or radiograph
c. Ultrasonics and / or liquid penetrant
d. Liquid penetrant and/or eddy currrent.

17. During periodic scheduled inspections, more extensive inspection should be applied to an area beginning ________________ upstream of the injection nozzle and continuing for at least ____________ pipe diameters downstream of the injection point.

a. 10 inches, 20
b. 12 feet, 10
c. 12 inches, 10
d. 10 feet, 10

18. Why should dead legs in piping be inspected?

a. API 510 mandates the inspection of dead legs
b. Acid products and debris build up in dead legs
c. The corrosion rate in dead legs can vary significantly from adjacent active piping
d. Caustic products and debris build up in dead legs

19. Both the stagnant end the connection to an active line of a dead leg should be monitored. In piping systems, why does the high point of a dead leg corrode and need to be inspected?

a. Corrosion occurs due to directed currents set up in the dead leg
b. Erosion occurs due to convective currents set up in the dead leg
c. Corrosion occurs due to convective currents set up in the dead leg
d. Erosion occurs due to directed currents set up in the dead leg

20. What is the best thing to do with dead legs that are no longer in service?

a. Ultrasonically inspect often
b. Radiograph often
c. Inspect often
d. Remove them.

21. What are the most common forms of corrosion under insulation (CUI)

a. Localized corrosion of nonferrous metals and chloride stress corrosion cracking of carbon steel.
b. Localized corrosion of chrome-molly steel and chloride stress corrosion cracking of erratic stainless steel.
c. Localized corrosion of carbon steel and chloride stress corrosion cracking of austenitic stainless steel.
d. Localized corrosion of nickel-silicon alloy and caustic stress corrosion of austenitic stainless steel

22. What climatic area may require a very active program for corrosion cracking of austenitic stainless steel

a. Cooler northern continent locations
b. Cooler drier, mid-continent locations
c. Warmer, marine locations
d. Warmer drier, desert locations.

23. Certain areas and types of piping systems are potentially more susceptible to corrosion under insulation. Which of the items listed is not susceptible to CUI?

a. Areas exposed to mist overspray from cooling water towers
b. Carbon steel piping systems that normally operate in-service above 250 degrees but are in intermittent service
c. Dead legs and attachments that protrude from insulated piping and operate at a different temperature than the temperature of the active line.
d. Carbon steel piping systems , operating between 250 degrees F and 600 degrees F.

24. What location is subject to corrosion under insulation and inspection contributes to it.

a. Locations where insulation has been stripped to permit inspection of the piping
b. Locations where insulation has been stripped to permit inspection of the piping
c. Locations where insulation plugs have been removed to permit piping thickness measurements
d. Locations where is damaged or missing insulation jacketing

25. Soil-to-air (S/A) interfaces for buried piping area a location where localized corrosion may take place. If the buried part is excavated for inspection, how deep should the excavation be to determine if there is hidden damage?

a. 12 to 18 inches
b. 6 to 12 inches
c. 12 to 24 inches
d. 6 to 18 inches

26. At concrete-to-air and asphalt-to-air interfaces of buried piping without cathodic protection, the inspector should look for evidence that the caulking or seal at the interface has deteriorated and allowed moisture ingress. If such a condition exists on piping systems over _______________ years old, it may be necessary to inspect for corrosion beneath the surface before resealing the joint.

a. 8
b. 5
c. 15
d. 10

27. An example of service-specific and localized corrosion is:

a. Corrosion under insulation in areas exposed to steam vents
b. Unanticipated acid or caustic carryover from process into non-alloyed piping
c. Corrosion in dead legs
d. Corrosion of underground piping at soil-to-air interface where it ingresses

28. Erosion can be defined as:

a. Galvanic corrosion of a material where uniform losses occur
b. Removal of surface material by action of numerous impacts of solid or liquid particles
c. Gradual loss of material by a corrosive medium acting uniformly on the material
d. Pitting on the surface of a material to the extent that a rough uniform loss occurs

29. A combination o corrosion and erosion results in significantly greater metal loss than can be expected from corrosion or erosion alone. This type of loss occurs at:

a. high-velocity and high-turbulence areas
b. Areas where condensation or exposure to wet hydrogen sulfide or carbonates occur.
c. surface-to air interfaces of buried piping
d. Areas where gradual loss of material by long time exposure to high temperature and stress.

30. Environmental cracking of austenitic stainless steels is caused many times by:

a. Exposing areas to high-velocity and high-turbulence streams
b. Excessive cyclic stresses that are often very low
c. Exposure to chlorides from salt water, wash-up water, etc.
d. Creep of the material by long time exposure to high temperature and stress.

31. When the inspector suspects or I advised that specific piping circuits may be susceptible to environmental cracking the inspector should:

a. Call in Piping Engineer for consultation
b. Investigate the history of the piping circuit
c. Obtain advise from a Metallurgical Engineer
d. Schedule supplemental inspections

32. If environmental cracking is detected during internal inspection of pressure vessels, what should the Inspector do?
a. The Inspector should designate appropriate piping spools upstream and downstream of the vessel to be inspected if piping is susceptible to environmental cracking.
b. The Inspector should consult with a Metallurgical Engineer to determine the extent of the problems
c. The Inspector should review the history of adjacent piping to determine if it has ever been affected
d. The Inspector should consult with a Piping Engineer to determine the extent of the problems.

33. If external or internal coatings or refractory liners on a piping circuit are in good condition, what should an inspector do?

a. After inspection, select a portion of the liners for removal
b. The entire liner should be removed for inspection
c. Selected portions of the liner should be removed for inspection
d. After inspection, if any separation, breaks, holes or blisters are found, it may be necessary to remove portions of the lining to determine the condition under it.

34. What course of action should be followed if a coating of coke is found on the interior of a large pipe off a reactor on a Fluid Catalytic Unit.

a. Determine whether such deposits have active corrosion beneath them. If corrosion is present, thorough inspection in selected areas may be required.
b. The coke deposits should be removed from the area for inspection
c. The coke deposits may be ignored – the deposits will probably protect the line from corrosion
d. Consult with a Process Engineer and a Metallurgist on the necessity of removing the coke deposits

35. Fatigue cracking of piping systems may results from;

a. Embitterment of the metal due to it operating below its transition temperature
b. Erosion or corrosion/erosion that thin the piping where it cracks
c. Excessive cyclic stresses that are often well below the static yield strength of the material
d. Environmental cracking caused by stress corrosion due to the presence of caustic, amine or other substance.

36. Where can fatigue cracking typically be first detected?

a. At points of low-stress intensification such as reinforced nozzles
b. At points of high-stress intensification such as branch connections
c. At points where cyclic stress are very low
d. At points where are only bending or compressive stresses

37. What are the preferred NDE methods for detecting fatigue cracking

a. Eddy current testing, ultrasonic A-scan testing and / or possibly hammer testing
b. Liquid penetrate testing, magnetic particle testing and / or possibly acoustic emission testing
c. Visual testing, eddy current testing and/or possibly ultrasonic testing
d. Acoustic emission testing, hydro-testing, and/or possibly ultrasonic testing.

38. Creep is dependent on :

a. time, temperature and stress
b. material, product contained and stress
c. temperature, corrosive medium and load
d. Time, product contained and load

39. An example of where creep cracking has been experienced in the industry is in the industry is in the problems experienced with cracking of 1.25% Chrome steels operating at temperature above ___________________degrees F.

a. 500
b. 900
c. 1000
d. 1200

40. Brittle fracture can be occur in carbon, low-alloy and other ferritic steels at or below_________ temperature.

a. 140 degree
b. ambient
c. 100 degree
d. 30 degree

41. Water and aqueous solutions in piping systems may freeze and cause failure because of the:

a. Expansion of these materials
b. Contraction of these materials
c. Constriction of these materials
d. Decrease of these materials

42. Different types of inspection and surveillance are appropriate depending on the circumstances and the piping system. Pick the one that does not belong in the following list

a. Internal and external visual inspection
b. Thickness measurement inspection
c. Vibrating piping inspection
d. Chemical analysis inspection

43. Internal visual inspections are ____________ on piping unless it is a large diameter transfer line, duct, catalyst line or other large diameter piping system.

a. The most effective inspection
b. The most useful means of inspection
c. The major means of inspection

44. Name an additional opportunity for a normal non-destructive internal inspection of piping

a. When the piping fails and the interior is revealed
b. When maintenance asks for an internal inspection
c. When piping flanges are disconnect
d. When a fire occurs and the pipe is in the fire

45. Why is thickness measurement inspection performed?

a. To satisfy jurisdictional requirements
b. To determine the internal condition and remaining thickness of the piping components
c. To determine the external condition and amount of deposits inside the piping
d. To satisfy heat transfer requirements of the piping

46. Who performs a thickness measurement inspection?

a. The operator or control man
b. The Inspector or examiner
c. The maintenance workers or supervisor
d. The jurisdiction or OSHA

47. When corrosion product buildup is noted during an external visual inspection at pipe support contact area lifting off such supports may be required for inspection. When doing this, care should be:

a. Exercised if the piping is in-services
b. Used when determining the course of action
c. Practiced so as not to disturb the supports
d. Taken that a complete record of the problem is made

48. Qualified operating or maintenance personnel also may conduct external visual inspections, when:

a. Satisfactory to the owner-user
b. Acceptable to the inspector
c. Agreeable to the maintenance supervisor
d. Permissible to the operation supervisor

49. Who would normally report vibrating or swaying piping to engineering or inspection personnel?

a. Operating personnel
b. Maintenance personnel
c. Jurisdictional personnel
d. OSHA personnel

50. Thermograph is used to check for:

a. Vibrating sections of the piping system
b. Detecting localized corrosion in the piping system
c. Abnormal thermal expansion of piping system
d. Hot spots in refractory lined piping systems

51. Thickness measurement locations (TML) are specific ____________________along the piping circuit where inspections are to be made

a. points
b. Areas
c. Items
d. Junctures

52. The minimum thickness at each TML can be located:

a. Electromagnetic techniques
b. Ultrasonic scanning or radiography
c. Hammer testing
d. MT and/or PT.

53. Where appropriate, thickness measurements should include measurements at each of _______on pipe and fittings

a. Two quadrants
b. Three locations
c. Four quadrants
d. Six points

54. Where should special attention be placed when taking thickness measurements of an elbow?

a. The outlet end
b. The inlet end
c. The inside and outside radius
d. The sides

55. TML should be marked drawings and ____________________ to allow repetitive measurements.

a. On the inspectors notes
b. On a computer system
c. On the piping system
d. On maintenance department charts

56. What is taken into account by an experienced inspector when selecting TML ?

a. The amount of corrosion expected
b. The patterns of corrosion that would be expected
c. The number and the cost of reading the TML
d. Whether the TML are easily accessed

57. In theory, a piping circuit subject to perfectly uniform corrosion could be adequately monitored with ______ TML

a. 1
b. 2
c. 3
d. 4

58. More TML should be selected for piping systems with any of the following characteristics:

a. Low potential; for creating a safety or environmental emergency in the event of a leak
b. More complexity in terms of fittings, branches, dead legs, injection points, etc.
c. Relatively non-corrosive piping systems
d. long, straight-run piping systems

59. Fewer TML can be selected for piping systems with any of the following characteristics:

a. More complexity in terms of fittings, branches, dead legs, injections, etc.
b. Higher expected or experienced corrosion rates
c. long, straight-run piping systems
d. Higher potential for localized corrosion

60. TML can be eliminated for piping systems with the following characteristics:

a. Higher potential for creating a safety or environmental emergency in the event of a leak
b. Low potential for creating a safety or environmental emergency in the event of a leak.
c. Extremely low potential for creating a safety or environmental emergency in the event of a leak
d. More complexity in terms of fittings, branches, dead legs, injection points, etc.

61. What is usually the most accurate means for obtaining thickness measurements on installed pipe larger than NPS 1?

a. MT
b. UT
c. PT
d. ET

62. What thickness measuring technique does not require the removal of some external piping insulation?

a. AE
b. UT
c. ET
d. RT

63. When ultrasonic thickness measurements are taken above _______________ degrees F, instruments complaints and procedures should be used that will result in accurate measurements at the higher temperature.

a. 150
b. 175
c. 200
d. 250

64. Typical digital thickness gages may have trouble measuring thickness less than ___________ inches

a. 0.2188
b. 0.1875
c. 0.1562
d. 0.1250

65. When pressure testing of piping systems are conducted they shall be performed in accordance with the requirements of:

a. ASME B31.3
b. ASME B & PV Code, Section VIII
c. ASA B16.5
d. API 510

66. If a lower pressure test (lower than prescribed by code) is used only for tightness of piping systems, the __________ may designate the pressure.

a. owner-user
b. Inspector
c. Jurisdiction
d. Contractor

67. The preferred medium for a pressure test is _______________

a. steam
b. Air
c. Water
d. Hydrocarbon

68. If a non-toxic hydrocarbon (flammable) is used as the test medium, the liquid flash point shall be at least __________ degrees F or greater.

a. 95
b. 100
c. 110
d. 120

69. Piping fabricated of or having components of 300 series stainless steel be tested with ________.

a. Water with a pH of 4
b. Water with a pH of 6
c. Water with a chloride content of less than 400 ppm chlorides
d. Steam condensate

70. For sensitized austenitic stainless steel piping subject to polythionic stress corrosion cracking, consideration should be given to using ____________________ for pressure testing.

a. An acidic-water solution
b. An alkaline-water solution
c. A water with a pH of 5
d. A water with a pH of 4

71. When a pipe requires post weld heat treatment, when should the pressure test be performed

a. During heat treatment
b. Before any heat treatment
c. After any heat treatment
d. No test is required

72. During a pressure test, where the test pressure will exceed the set pressure of the safety relief valve or valves on a piping system the safety relief valves or valves should be ______________ when carrying out the test.

a. Altered by screwing down on the adjusting screw
b. Reset to exceed the test pressure
c. Checked or tested
d. Removed or blanked

73. If block valves are used to isolate a piping system for a pressure test, what precaution should be taken?

a. Do not use a globe valve during a test
b. Make sure the packing gland of the valve is tight
c. Do not exceed the permissible seat pressure of the valve
d. Check the bonnet bolts to make sure they are tight.

74. Several methods may be used to verify that the correct alloy piping in a system. Which of the following methods be used:

a. 100% verification
b. PMI testing
c. Sampling a percentage of materials
d. Any of the above may be used

75. Name a part of a piping system that thickness measurements are not normally routinely taken

a. elbows
b. Expansion loops
c. Tees
d. Valves

76. If environmental cracking is found during in-service inspection of welds, who should conduct the ultrasonic shear wave examination, if required?

a. owner-user
b. Inspector
c. Industry-qualified UT Examiner (after 2003)
d. Industry-qualified inspection-engineers

77. If an inspector finds an imperfection in an original fabrication weld and analysis is required to assess the impact of the weld quality on piping integrity, which of the following may perform the analysis?

a. An API 510 inspector, a WPS Inspector, a Pressure Vessel Engineer
b. An API 570 inspector, a CWI Inspector, a Piping Engineer
c. An owner-User, a B31.3 Inspector, an Industrial Engineer
d. A Jurisdictional Representative, a API 574 Inspector, an Chemical Engineer

78. According to API 570, some welds in a piping system that has been subjected to radiography according to ASME B31.3 :

a. Will meet random radiograph requirements, and will perform satisfactory in-service without a hydro test
b. Will meet random radiograph requirements, and will perform satisfactory in-service even though hydro tested.
c. Will meet random radiograph requirements, and will not perform satisfactorily in-service after hydro test
d. Will meet random radiograph requirements, but will still perform satisfactorily in-service after hydro tested.

79. How should fasteners and gaskets be examined to determine whether they meet the material specifications

a. All fasteners and gaskets should be checked to see if their markings are correct according to ASME and ASTM standards.
b. A representative sample of the fasteners and baskets should be checked to see if their markings are correct according to ASME and ASTM standards
c. Purchase records of all fasteners and gaskets should be checked to see if the fasteners and gaskets meet ASME and ASTM standards
d. A representative sample of the purchase records of fasteners and gaskets should be checked to see if the fasteners and gaskets meet ASME and ASTM standards.

80. When checking flange and valve bonnet bolts for corrosion, what type of NDT is usually used?

a. RT
b. UT
c. VT
d. AE

81. What course of action is called for when an inspector finds a flange joint that has been clamped and pumped with sealant ?

a. Disassemble the flange joint; Renew the fasteners and gaskets .The flanges may also require renewal or repair
b. Renew all the fasteners and renew gasket if leakage is still apparent
c. Check for leakage at the bolts; if repumping is contemplated , affected fasteners should be renewed
d. No action is required since the joint has been pumped with a sealant

82. All process piping systems must be categorized into different classes. On what are the classifications selection based?

a. Requirements of jurisdiction and the proximity of population areas
b. Potential safety and environmental effects should a leak occur
c. Liability to the owner-user and the requirements of the jurisdiction
d. Access to the systems for inspection and closeness to population areas

82. (1). Inspection strategy based on like hood and consequence of failure is called:

a. RBI
b. FFS
c. BIR
d. MSOS

82. (2). An RBI assessment can be used to __________________ the inspection interval limits in Table 1 of API 570 **or** the extent of the inspection conducted.

a. increase
b. Decrease
c. Either a or b, above
d. None of the above

82. (3). When an RBI assessment is used to increase or decrease inspection intervals, the assessment **shall** be conducted on Class 1 systems at a maximum interval of__________ years.

a. 5
b. 10
c. 15
d. 3

83. Listed below are several examples of a CLASS 1 piping system. Which one does not belong?

a. Anhydrous hydrogen chloride
b. Hydrofluoric acid
c. Piping over adjacent to water and piping over public throughways
d. Distillate and product lines to and from storage and loading

84. Of the classification of piping systems, which includes the majority of unit process and selected off-site piping?

a. Class 3
b. Combination of classes 1 and 2
c. Class 1
d. Class 2

85. Class 3 piping is described as being in services:

a. With the highest potential of resulting in an immediate emergency if leak occurs.
b. That are flammable but do not significantly vaporize when they leak and are located in high-activity areas.
c. That are not flammable and pose no significant risk to populated areas
d. That are not in class 1 and 2

86. Who establishes inspection interval for thickness measurements, external visual inspections and for internal and supplemental inspections?

a. Piping Engineer
b. Owner-user or the Inspector
c. Chemical Engineer
d. Piping Engineer and the Jurisdiction

87. Thickness measurement inspection should be scheduled based on the calculation of not more than:

a. One half the remaining life determined from corrosion rates or the maximum interval of 5 years whichever is shorter
b. One half the remaining life determined from corrosion rates or the maximum interval allowed by API 570 in Table 1, whichever is shorter.
c. One fourth the remaining life determined from corrosion rates or the maximum interval of 10 years whichever is shorter.
d. One quarter the remaining life determined from corrosion rates or the maximum interval allowed by API 570 in Table 1, whichever is shorter.

88. For External inspections for potential corrosion under insulation (CUI) on Class 1 systems, the examination should include at least ____________percent of all suspect areas and ___ ________percent of all areas of damaged insulation.

a. 50, 75
b. 50, 33
c. 75, 50
d. 25, 10

89. Piping systems that are known to have a remaining life of over _____years or that are protected against external corrosion need not have insulation removed for the periodic external inspection.

a. 10
b. 15
c. 5
d. 20

90. For Class 3 piping systems, the examination for corrosion under insulation (CUI) should include at least __________________ percent of all suspect areas

a. 50
b. 30
c. 10
d. 0

91. For Class 2 piping, the extent of CUI inspections on a system operating at – 45 F will be:

a. 75% of damaged areas, 50% of suspect areas
b. 50% of suspect areas, 33% of damaged areas
c. 33% of damaged areas, 50% of suspect areas
d. None of the above

92. Small bore piping (SBP) that is Class be inspected:

a. Where corrosion has been experienced
b. At the option of the inspector
c. To the same requirements as primary process piping
d. Only if it has dead legs.

93. Inspection of small bore piping (SBP) that is secondary and auxiliary (associated with instruments and machinery) is:

a. Only required where corrosion has been experienced
b. Optional
c. Only if has dead legs
d. Only if it is threaded

94. If an inspector finds threaded small bore piping (SBP) associated with machinery and subject to fatigue damage, he should:

a. Plan periodically to assess it and consider it for possible renewal with a thicker wall or upgrade it to welded components
b. Inspect it only if it is corroded and the class of service requires an inspection
c. Call for dismantling the threaded joints for close inspection to determine if any cracks are in the roots of the threads
d. Have all the threaded piping renewed at each inspection period

95. An eight inch diameter piping system is installed December, 1979. the installed thickness is measured as 0.34”. The required thickness of the pipe is 0.20”. It is inspected on 12/83 and the thickness is found to be 0.32”. An inspection 12/87 reveals a loss of 0.01” from the 12/85 inspections. During 12/89 the thickness was found to be 0.29”. The last inspection was during 12/95 and the thickness was found to be 0.26”. What is the long term corrosion rate of this system?

a. 0.005” / year
b. 0.0075” / year
c. 0.00375” / year
d. 0.0025” / year

96. Using the information in questions 95, calculate the short term corrosion rate.

a. 0.005” / year
b. 0.0075” / year
c. 0.00375” / year
d. 0.0025” / year

97. Using the information in questions 95 and 96, determine the remaining life of the system

a. 18 years
b. 15 years
c. 12 years
d. 6 years

98. You have a new piping system that has just been installed. It is completely new an no information exists to establish a corrosion rate. Also, information is not available on a similar system. You decide to put the system in service and NDT it later to determine the corrosion rate. How long do you allow the system to stay in service before you take your first thickness readings?

a. 1 month
b. 3 month
c. 6 month
d. 12 month

99. After an inspection interval is completed and if calculations indicate that an inaccurate rate of corrosion has been assumed in a piping system, how do you determine the corrosion rate for the next inspection period?

a. Check the original calculations to find out what the error is in the original assumption
b. Unless the corrosion rate is higher, the initial rates shall be used
c. The corrosion rate shall be adjusted to agree with the actual rate found
d. If the corrosion rate is higher than originally assumed, call in a corrosion specialist

100. If a piping system is made up of unknown materials and computations must be made to determine the minimum thickness of the pipe, what can the inspector or the piping engineer to do establish the minimum thickness?

a. The lowest grade material and joint efficiency in the applicable code may be assumed for calculations
b. Samples must be taken from the piping and testing for maximum tensile stress and yield strength will determine the allowable stress to be used
c. The piping made of the unknown material must be removed from service and current piping of known material must be installed
d. The piping of unknown material may be subjected to a hydrostatic stress tests while having strain gages on it to determine its yield strength and thus allowable stress

101. A piping engineer is designing a piping service with high potential consequences if a failure occurs, i.e., a 350 psi natural gas line adjacent to a high density population area. What should be consider doing to provide for unanticipated situations?

a. Have all his calculations checked twice
b. Increase the required minimum thickness
c. Notify the owner-user and the jurisdiction
d. Set up an emergency evaluation procedure

102. When evaluating locally thinned areas, the provisions of RP 579 Section ________________ should be followed

a. 4
b. 5
c. 6
d. 7

103. An inspector finds a thin area in a fabricated 24” diameter pipe. The thin area includes a longitudinal weld in the pipe and is 10 feet long and 2 foot circumferentially. Calculations show that with 0.85 joint factor, the pipe must be repaired, renewed, etc. or the pressure in the pipe must be lowered. The owner does not want do any hot work on the pipe and he does not wish to lower the pressure. What other course could be followed, per API 570?

a. Write the results of the inspection up and leave it with the owner
b. Conduct an FFS per RP 579
c. Insist that the weld be repaired or renewed or that the pressure be lowered
d. Call in a regulatory agency to force the owner to repair, renew, etc. the line.

104. Piping stress analysis is done during the system’s original design. How can the inspector make use of stress analysis information?

a. An inspector can not use this information. It is only meaningful to a piping engineer
b. It can be used to make sure the piping system was originally evaluated and designed correctly
c. It can be used to concentrate inspection efforts at locations most prone to fatigue or creep damage and to solve vibration problems
d. The inspector should use this information to evaluate the need for conducting additional piping stress analysis

105. You are inspecting a piping system. You find a significant loss of material (a major increase of corrosion rate) in gas oil piping (used as re boiler oil, temperature 500 degrees F) on an Fluid Catalyst Cracking Unit. What is the best course of action for you to take?

a. The losses may be reported to your supervisor for corrective response
b. The losses should be recorded & reported in your final report after the unit has started
c. It shall be reported to the owner-user for appropriate action
d. Replace excessively thin piping & note replacement in the final report after unit start-up

106. The ___________________ shall maintain appropriate permanent and progressive records of each piping system covered by API 570.

a. inspector
b. owner-user
c. Jurisdiction
d. Examiner

107. When making repairs and alterations to piping systems the principles of _________________ or the code to which the piping system was built shall be followed

a. ASME B31.3
b. API 570
c. API 574
d. ASME B & PV Code

108. Repair and alteration work must be done by a repair organization as defined in API 570 and must be authorized by the ______________ prior to its commencement.

a. jurisdiction
b. Inspector
c. owner-user
d. Examiner

109. Authorization for alteration work to a piping system may be given by the inspector after:

a. Notifying the jurisdiction and getting their approval
b. Consulting API 570 and getting the approval of the owner-user
c. Consultation with and approval by a piping engineer
d. Discussing with and consent by an examiner

110. A repair procedure involving welding requires that the root pass of the weld be inspected before continuing the weld. A “hold” on the repair is required at this point. Who designates this “hold”?

a. A metallurgist
b. The owner-user
c. An API 570 inspector
d. The welder supervisor

111. What type of repairs and procedures may the inspector give prior general authorization to continue (provided the inspector is satisfied with the competency or the repair organization?

a. Major repairs and minor procedures
b. Limited or routine repairs and procedures
c. Alterations and reratings
d. Minor reratings and alterations

112. Who approves all proposed methods of design, execution, materials, welding procedures, examination and testing of in-service piping?

a. The jurisdiction or the piping engineer as appropriate
b. The analyst and the operator as appropriate
c. The examiner and the piping programmer as appropriate
d. The inspector or the piping engineer, as appropriate

113. Who must give approval for any on-stream welding?

a. owner-user
b. Jurisdiction
c. Examiner
d. Analyst

114. An inspector finds a crack in the parent metal of a pipe adjacent to a support lug. The pipe was being inspected after a 5 year run. Before repairing the he should:

a. Notify the jurisdiction prior to the start of any repairs
b. Write a detailed procedure for the repair organizations use in repairing the crack
c. Consult with the piping engineer to identify and correct the cause of the crack
d. Consult with a metallurgist prior to writing a procedure to repair the crack

115. A full encirclement welded spilt sleeve designed by a piping engineer may be applied over a damaged or corroded area of a pipe. This is considered a temporary repair. When should a permanent repair be made?

a. If the owner-user designates the welded split sleeve as permanent, it may remain
b. A full encirclement welded split sleeve is permanent if okayed by the inspector
c. A full encirclement welded split sleeve is considered a permanent repair
d. A permanent repair must be made at the next available maintenance opportunity

116. What type of defect, corrosion, pitting and/or discontinuity should not be repaired by a full encirclement welded split sleeve?

a. A longitudinal crack
b. A circumferential crack
c. Pits that are one half through wall
d. General corrosion in the longitudinal direction

117. If a repair area is localized (for example, pitting or pin-holes) and the specified minimum yield strength (SMYS) of the pipe is not more than ___ psi, a temporary repair may be made by fillet welding a properly designed plate patch over the pitted area.

a. 30, 000 psi
b. 55, 000 psi
c. 40, 000 psi
d. 36, 000 psi

118. Insert patches (flush patches may be used to repair damaged or corroded areas of pipe if several requirements are met. One of these is that an insert patch (flush patch) may be of any shape but it shall have rounded corners with ____________ minimum radii

a. 0.375”
b. 0.50”
c. 0.75”
d. 1”

119. An inspector finds a pin-hole leak in a weld during an on-stream inspection of a piping system. A permissible temporary repair is:

a. The use of plastic steel to seal off the leak
b. Driving a wooden plug into the hole
c. Screwing a self tapping screw into the hole
d. The installation of a properly designed and fabricated bolted leak clamp

120. Temporary leak sealing and leak dissipating devices shall be removed and the pipe restored to original integrity:

a. As soon as the piping system can be safely removed from service
b. At a turnaround or other appropriate time
c. When the leak seal and leak dissipating device ceases to work
d. As soon as possible-must be done on a safe, emergency shut-down basis

121. Which of the following is **NOT** an item for consideration by an inspector when a leak sealing fluid (“pumping”) is used for a temporary leak seal repair.

a. Consider the compatibility of the sealant with the leaking material
b. Consider the pumping pressure on the clamp (especially when repumping)
c. Consider the pressure testing of the piping in question
d. Consider the number of times the seal area is repumped

122. Any welding conducted on piping components in operation must be done in accordance with:

a. NFPA 704
b. API Standard 510
c. ASME B31.3
d. API Publication 2201

123. All repair and alteration welding to piping systems shall be done in accordance with the:

a. Exact procedures of ASME B31.3 or to the code to it was built
b. Standards of ASME B31.1 or the code to which it was built
c. Principles of ASME B31.3 or the code to which it was built
d. Ideals of ASME, NBIC or API standards

124. Welders and welding procedures used in making piping repairs, etc. shall be qualified in accordance with:

a. ASME B31.3 or the code which the piping was built
b. NBIC or the system to do which the piping was built
c. NACE or the method to do which the piping was built
d. ASTM or the law to which the piping was built

125. The repair organization responsible for welding shall maintain records of welding procedure and welder performance qualifications. These records shall be available to the inspector:

a. At the end of the job
b. After the start of welding
c. Following the start of welding
d. Before the start of welding

126. Preheating to not less than _____________ degrees F. may be considered as an alternative to post weld heat treatment for alterations or repairs of P – 1 piping initially post weld heat treated as a code requirement (may not be used if the piping was post weld heat treated due to environmental cracking prevention)

a. 150
b. 200
c. 300
d.350

127. When using local PWHT as a substitute for 360-degree banding on local repairs of PWHT ‘d piping, which of the following items is **NOT** considered?

a. The application is reviewed and a procedure is developed by the piping engineer
b. The locally PWHT ’d area of the pipe must be RT ’d or UT ’d.
c. A preheat of 300°F ;or higher is maintained while welding
d. The PWHT is performed for code compliance and not for environmental cracking

128. Piping butt joints shall be:

a. Double spiral fillet welds
b. Single fillet lap welds
c. Double fillet lap welds
d. full-penetration groove welds

129. When should piping components that need repair be replaced?

a. When enough time remains on a turnaround to allow replacement
b. When repair is likely to be inadequate
c. When the cost of repair is as high as renewal
d. When replacement is preferred by maintenance personnel

130. Fillet welded patches (lap patches) shall be designed by:

a. An engineer
b. The inspector
c. The piping engineer
d. The repair organization

131. Fillet welded lap patches (overly patches) shall have:

a. No membrane stresses
b. Right –angled corners
c. Rounded corners
d. Burnished corners

132. Material used in making welding repairs or alterations _________________ be known weld able quality

a. may
b. Shall
c. Should
d. Can

133. Acceptance of a welded repair or alteration shall include _______________ in accordance with the applicable code and the owner-user specification, unless other wise specified in API 570.

a. Nominal pragmatic sizing
b. NBE
c. Safeguards
d. Nondestructive examination

134. After welding is completed on a repair or alteration, ____________________ in accordance with API 570 shall be performed if practical and deemed necessary by the inspector

a. NPS
b. Safety sanctions
c. NBE
d. A pressure test

135. When are pressure tests normally required?

a. Pressure tests are normally required after alteration and any repair
b. Pressure tests are normally required after alteration and major repairs
c. Pressure tests are normally required after major and minor repairs
d. Pressure tests are normally required only as specified by the owner-user

136. When a pressure test is not necessary or practical, what shall be utilized in lieu of a pressure test?
a. NPS
b. Nondestructive examination
c. Vacuum visual examination
d. NBE

137. Substituting special procedures in place of a pressure test after an alteration or repair may be done only after consultation with:

a. The operators and the repair organization
b. The inspector and the piping engineer
c. The jurisdiction
d. The examiner and the inspector

138. When it is not practical to perform a pressure test of a final closure weld that joints a new or replacement section of piping to an existing system, several requirements shall be satisfied. Which of the following is **NOT** one the requirements.

a. The closure weld is a full-penetration fillet weld between a weld neck flange and standard piping component or straight sections of pipe of equal diameter and thickness, axially aligned and of equivalent materials. For design cases up to Class 150 and 500°F;slip-on flanges are acceptable alternates
b. MT or PT shall be performed on the root pass and the completed butt weld. Fillet welds must have PT/MT on the completed weld
c. The new or replacement piping is pressure tested.
d. Any final closure butt shall be of 100% radiographic quality; or angle-beam UT may be used, provide the appropriate acceptance criteria is established

139. Which of the following is **NOT** a requirement for rerating a piping system by changing the temperature or the MAWP

a. The existing pressure relieving devices are still in place & set as they were originally
b. Calculations are performed by the piping engineer or the inspector
c. Piping flexibility is adequate for design temperature changes.
d. A decrease in minimum operating temperature is justified by impact test results, if required by the applicable code.

140. Why is inspection of buried process piping (not regulated by DOT) different from other proces piping inspection?

a. The insulating effect of the soil increases the possibility of more internal corrosion
b. Internal corrosion has to be controlled by cathodic protection
c. Significant external deterioration can be caused by corrosive soil conditions
d. Internal corrosion must be controlled by internal coatings

141. Indications of leaks in buried piping may include several indications. Which of the ones listed below is **NOT** one of the indications.

a. A change in the surface contour of the ground
b. Water standing on the pipeline right-of-way
c. Discoloration of the soil
d. Notice odor

142. Corrosion cells can form on both bare and coated pipe where bare steel contacts the soil. How can these cells be detected?

a. Run an acoustic emission test on the piping
b. Visually survey the route of buried piping
c. The potential at the area of corrosion will be measurable different than other areas and a close-interval potential survey can detect the location of corrosion
d. Run a internal survey of the piping using a video camera

143. A pipe coating holiday survey is used to locate coating defects on coated pipes. It can be used on newly constructed pipe systems to ensure that the coating is intact and holiday-free. More often it is used on buried pipe to:

a. Show the measurable differences in electrical potential in corroded areas.
b. Evaluate coating serviceability for buried piping that has been in-service for a long time
c. Determine the depth of the piping for resistivity testing
d. Evaluate the cathodic protection components of the under-ground pipe.

144. Cathodically protected buried piping should be monitored _______________ to assure adequate levels of protection

a. regularly
b. Intermittently
c. Erratically
d. Frequently

145. If an “intelligent pigging” system is used to inspect buried piping, what type of bends are usually required in the piping system?

a. Five diameter bends
b. 90 degree pipe ells
c. Ten diameter bends
d. Three diameter bends

146. How often should above-grade visual surveillance of a buried pipeline right-of-way be made?

a. Once a month
b. Approximately 6 month intervals
c. Once a year
d. Once every 3 months

147. How often should poorly coated pipes with inconsistent cathodic protection potentials have a pipe-to-soil potential survey made?

a. yearly
b. Every 2 years
c. Every 5 years
d. Every 7 years

148. On buried piping, what is the frequency of pipe coating holiday surveys?

a. The frequency is governed by the leak test interval of the pipe.
b. It is usually based on indications that other forms of corrosion control are ineffective
c. Surveys are normally made every 5 years
d. Pipe coating holiday surveys are made when the pipe is excavated

149. For piping buried in lengths greater than ________________ feet and not cathodically protected, evaluation of soil corrosively should be performed at 5-year intervals.

a. 50
b. 75
c. 100
d.150

150. If buried piping is cathodically protected, the system should be monitored at intervals in accordance with Section 10 NACE RP0169 or Section 9 of API RP 651. API RP 651 specifies _________ interval.

a. annual
b. Biannual
c. Biennial
d. Triennial

151. Buried piping inspected periodically by excavation shall be inspected in lengths of _________ feet at one or more locations judged to be most susceptible to corrosion.

a. 2 to 4
b. 4 to 6
c. 6 to 8
d. 8 to 10

152. After excavation of buried piping, if inspection reveals damaged coating or corroded piping:

a. The condition should be noted in the records and the inspection interval shortened
b. The complete piping system must be day lighted (excavated) for repair or shortened
c. The damaged coating or corroded piping must be repaired or replaced
d. Additional piping shall be excavated until the extent of the condition is identified.

153. If buried piping is contained inside a casing pipe, the casing should be:

a. Capable of caring the same pressure as the product pipe
b. Checked to see if its protective coating is intact and serviceable
c. Pressure tested to make sure it is serviceable
d. Inspected to determine if water and/ or soil has entered the casing

154. An alternative or supplement to inspection of buried piping is leak testing with liquid at a pressure at least __________ % greater than the maximum operating pressure at intervals ½ the length of those shown in Table 9-1 of API 570 for piping **not** cathodically protected and the same intervals as shown in Table 9-1 for cathodically protected piping.

a. 5
b. 10
c. 25
d. 50

155. The leak test for buried piping should be for a period of ____________________ hours.

a. 4
b. 8
c. 12
d. 24

156. The leak test for a 8” diameter buried piping system is 300 psi. after 7 hours, the pressure reads 273 psi. what should the inspector do?

a. Nothing is required. The loss of pressure is negligible and will not affect the test. The loss can be disregarded.
b. The system should be repress red to the original leak test pressure and test should begin again.
c. The test charts and the temperature should be reviewed to determine if any change in temperature caused the pressure drop
d. The piping should be visually inspected externally and/or inspected internally to find the leak and assess the extent of corrosion.

157. A buried piping system that is not cathodically protected has to have an inspection interval set. The soil resistively is checked and found to be 3400 ohm-cm. As the inspector ,what interval of would you set ?

a. 2.5 years
b. 7.5 years
c. 5 years
d. 10 years

158. Buried piping also may be surveyed for integrity by removing the line from service and performing a leak test. This inspection method typically involves pressurizing the line with a __________ , allowing time for the _________ to diffuse to the surface, and surveying the buried line with a gas- specific detector to defect the ____________.

a. Tracer gas (such as helium or sulfur hexafluoride)
b. Light hydrocarbon (such as butane)
c. Smoke type material (such as chemical smoke)
d. Water vapor (such as steam)

159. Repairs to coatings on buried may be tested using:

a. A low-voltage holiday detector
b. Light taps with a inspection hammer
c. An flaw indicator fluid
d. A high-voltage holiday detector

160. If buried piping leaks are clamped and reburied;

a. No further action is required unless the piping leaks again
b. The date of installation shall be marked on the clamp for future identification
c. A record of the location and the date of installation shall be maintained.
d. The clamped line shall be leak tested

161. A 10” diameter piping system with 4” diameter reinforced branch connections is to have changes made to it. Which of the following is considered an alteration?

a. A new 1” diameter unreinforced nipple is installed
b. A new 8” diameter reinforced branch connection is installed
c. A new 4” diameter reinforced branch connection is installed
d. A new 3” diameter reinforced branch connection is installed

162. Which of the following **would not** be classified as an applicable code to which a piping system was built?

a. ASME B31.3
b. ASME B31.1
c. ASA B31.1-1955, Section 3
d. ASTM A-20

163. Which of the inspection agencies listed below is **NOT** an authorized inspection agency as defined in API 570?

a. Jurisdictional inspection organization
b. owner-user inspection organization
c. ASTM inspection organization
d. Independent inspection organization.

164. An authorized piping inspector is an employed of an authorized inspection agency who is qualified to perform the functions specified in API 570. which individual listed below is **not** usually an authorized piping inspector

a. An owner-user inspector
b. A jurisdictional inspector
c. An NDE examiner
d. An insurance inspector

165. Which of the following qualifies as auxiliary piping?

a. Control valve manifolds
b. Bypass lines around exchangers
c. Pump seal oil lines
d. Orifice runs

166. CUI stands for:

a. Control unit inspector
b. Corrosion under insulation
c. Corroded unobtrusive inserts
d. Corroded underground installation.

167. Dead legs of a piping system are:

a. The upstream piping of control valve manifolds
b. Supports attached to a pipeline that has no product in them
c. The upstream part of an orifice runs
d. Sections that normally have no significant flow.

168. A defect is an imperfection of a type or magnitude exceeding the __________ criteria.

a. nonspecific
b. Imprecise
c. General
d. Acceptable

169. The design temperature of a piping system component is the temperature at which, under the coincident pressure, the ____ is required

a. Smallest thickness or highest component rating
b. Greatest thickness or highest component rating
c. Maximum thickness or lowest component rating
d. Minimum thickness or minimum component rating.

170. An examiner is a person who ____________ the inspector.

a. Supplants
b. Assists
c. Supervises
d. directs

171. Hold point is a point in the repair or alteration process beyond which work may not proceed until the ________________ has been performed and documented.

a. PWHT required
b. required inspection
c. RT required
d. Ultrasonic testing

172. What is an imperfection?

a. It is a flow or discontinuity noted inspection that may be subject to acceptance
b. It is a defect noted during inspection that is unacceptable
c. It is a weld flaw noted during an inspection that may be subject to repair
d. It is a blemish that is only cosmetic and acceptable under all conditions

173. _________ : is a response or evidence resulting from the application of a nondestructive evaluation technique.

a. indication
b. Imperfection
c. Breach
d. Division

174. What are points where chlorine is introduced in reformers, water is added in overhead systems, etc. called

a. Primary process points
b. Level bridle points
c. Injection melting
d. Graphitization

175. What is the loss of ductility and notch toughness in susceptible low-alloy steels such as 1.25 and 2.5 Cr., due to prolonged exposure to high-temperature service called?

a. creep
b. Temper embitterment
c. Incipient melting
d. Graphitization

176. Secondary process piping is small-bore (less than or equal to ____________) process piping downstream of normally closed block valves.

a. NPS 3/4
b. NPS 1
c. NPS 2
d. NPS 3

177. A test point is an area defined by a circle having not greater than _________ inches for a line diameter not exceeding 10 inches or not greater than ___________________ inches for larger lines.

a. 3,4
b. 2, 3
c. 1, 2
d. 3/4 , 1

178. When making a repair utilizing a welded full encirclement repair sleeve and the sleeve material is different from the pipe material, you should:

a. Consult the piping engineer
b. Use a weld rod matching the higher strength material
c. Use a weld rod matching the lower strength material
d. Use a weld rod such as Inco-A

179. What type of electrode should be used when welding a full encirclement repair sleeve?

a. low-hydrogen electrode
b. low-phosphorus electrode
c. low-chrome electrode
d. low-nitrogen electrode

180. Which of the following welding electrodes is low-hydrogen?

a. E6010
b. E7016
c. E7011
d. E7014

181. When welding a small repair patch, the diameter of electrodes used should not exceed:

a. 1/8”
b. 3/16”
c. 5/32”
d. 1/4’’

OPEN BOOK QUESTIONS

182. An industry-qualified UT examiner may be qualified by:

a. API
b. ASNT
c. An equivalent qualification approved by the owner/user
d. Either a or b, above

183. An FFS assessment for general metal loss must conducted to ____________

a. RP 578, Section 4
b. RP 579, Section 4
c. RP 579, Section 5
d. RP 579, Section 6

184. The difference between “retirement” thickness and “required” thickness is:

a. Retirement thickness includes corrosion/loading allowances
b. Required thickness includes corrosion/loading allowances
c. One is actual thickness – the other is measured thickness
d. Retirement thickness is when the pipe must be removed from service.

185. PMI testing is defined as:

a. Alloy analysis using an alloy tester
b. Spark testing
c. Any physical evaluation that confirms the alloy
d. A qualitative test to confirm carbon content

186. A 14” O.D pipe has a corroded area on it. What is the maximum size of a small repair patch that may be used to cover the corroded area?

a. 3.5”
b. 7”
c. 6”
d. 6.5”

187. A NPS 4 Schedule 80 (0.337” wall) branch is welded into a NPS Schedule 40(0.406” wall) header. What size cover fillet weld (t_c) is required over the full penetration groove weld? (Express answer to nearest hundredth)

a. 0.578”
b. 0.286”
c. 0.334”
d. 0.236”

188. A NPS 6 (6.625” od) seamless pipe made from ASTM A335 Grade P2 material operates at 800psi and 600 degrees F. The conditions require that a corrosion allowance of 0.125” be maintained. Calculate the minimum required thickness for thickness for these conditions.

a. 0.290”
b. 0.343”
c. 0.631’
d. 0.524”

189. A NPS 14 (14.00” od) seamless pipe made from ASTM A 106 Grade A material operates at 300psi and 600 degrees F. The pipe must cross a small ditch and it must be capable of supporting itself without a visible sag. A piping engineer states that the pipe must be at least 0.375” to support itself and the liquid product. He also states that a 0.125” corrosion allowance must be included. Calculate the minimum required thickness for the pipe.

a. 0.778’
b. 0.567”
c. 0.642”
d. 0.600”

190. A 10’ long carbon steel pipe is welded to a 10’ 18-8 stainless pipe and is heated uniformly to 475 degrees F. from 70 degrees F. Determine its total length after heating.

a. 20.067’
b. 20.156’
c. 20.234’
d. 20.095’

191. A blank is required between two NPS 10, class allowance of 0.175” is required. The inside diameter of the gasket surface is 9.25”. The blank is ASTM A516 Grade 70 material with no weld joint. Calculate the pressure design thickness required for the blank ASTM A 516 Grade 70 material with no weld joint. Calculate the pressure design thickness required for the blank.

a. 0.789”
b. 0.692”
c. 0.556”
d. 0.768”

192. A NPS 14 (14.00" od) seamless pipe made from ASTM A53 Grade B material operates at 60 psi 600 degrees F. Calculate the pressure design thickness for these conditions, using the formula:

a. 0.243"
b. 0.442"
c. 0.205'
d. 0.191"

193. A NPS 6 piping system is installed in December 1989. The installed thickness is measured at 0.719". The required thickness of the pipe is 0.456". It is inspected December 1994 and the measured thickness is 0.608". An inspection in December 1995 reveals a 0.025" loss from the December 1994 inspection. During December 1996 the thickness was measured to be 0.571" What is the long term corrosion rate of this system?

a. 0.01996"/year
b. 0.02567"/ year
c. 0.02114" /year
d. 0.03546" year

194. Using the data in question # 193, calculate the short term corrosion rate in mils per year (M/P year)

a. .0012 M/P year
b. .012 M/P year
c. .12 M/p year
d. 12 M/p year

195. Using the information in questions #193 and #194, determine the remaining life of the system.

a. 18 years
b. 5.44 years
c. 1.2 years
d. 6 years

196. Using the information in question #193-#195 and assuming an injection point in a Class 2 system with 7 years estimated until the next inspection, what would the next UT interval be?

a. 10 years
b. 5 years
c. 3 years
d. 2.72 years

197. A seamless NPs 10pipe, ASTM A106 Grade B material, operates at 750 psi and 700 degrees F. maximum. Considering only pressure design thickness, what minimum thickness is required?

a. 0.24”
b. 0.20’
c. 0.28”
d. 0.17’

198. A seamless NPS 16 pipe, ASTM A135 Grade a material operates at 550 psi and 600 degrees F. maximum. The thickness of the pipe as determined by the last inspection is 0.40”. The pipe has been in service for 8 years. The original thickness at installation was measured to be 0.844” Two years previous to the 0.40” measurement the thickness of the pipe was found to be 0.54”. Determine the greatest corrosion rate, i.e. short or long term in mils per year (M/P year)

a. 55 M/P year
b. 70 M/P year
c. 70 M/P year
d. 700 M/P year

199. A seamless NPS 12 pipe, ASTM A106 Grade B material operates at 750 psi and 700 degrees F. maximum. The thickness of the pipe as determined by the last inspection is 0.305”. The pipe has been in service for 13 years. The original thickness at installation was measured to be 0.405” . Two years previous to the 0.305” measurement the thickness of the pipe found to be 0.316”. The next planned inspection is scheduled for 8 years. Using the appropriate corrosion rate determine what the pipe will withstand at the next inspection period.

a. 720 psi
b. 499 psi
c. 611 psi
d. 550 psi

200. A seamless NPS 6, ASTM A106 Grade A pipe operates at 300 degrees F and 765 psi. The allowable stress is 16,000 psi. using the Barlow equation, determine the required thickness for these conditions.

a. 0.446”
b. 0.332”
c. 0.231”
d. 0.155”

201. A seamless NPS 8, ASTM A106 Grade A pipe operates at 300 degrees F. and 741 psi. The allowable stress is 16,000 psi. The owner-user specified that the pipe must have 0.125” for corrosion allowance. Using the B31.3 equation, determine the required thickness for these conditions.

a. 0.295”
b. 0.195”
c. 0.321”
d. 0.392”

202. A NPS 4 schedule 80 (0.337” wall) branch connection is welded into a NPS 6 Schedule 40 (0.280” wall). A .375” reinforcing pad is used around the branch connection. The fillet weld sizes are as required by the Code. The branch connection is inserted into the header. The material of the branch and header is ASTM A672 Grade B70. What thickness would be used to determine whether heat treatment of the this connection is required? (Express answer to nearest hundredth)

a. 0.768”
b. 0.891”
c. 0.998’
d. 0.567”

203. An Inspector finds a thin area in the body of a NPS 8, 600 1b. Gate valve body. The body is made from ASTM A216 WCB material. The system operates at 900 psi and 750 degrees F. Using a corrosion allowance of 0.152”, what minimum required thickness must the valve body have to continue to safety operate?

a. 0.492”
b. 0.617”
c. 0.510
d. 0.345

204. A seamless NPS 10pipe, ASTM A106 Gr. B material, operates at 750 psi and 700 degrees F. (maximum). The thickness of the pipe as determined by the last inspection is 0.30”. The pipe has been in service for 10 years. The original thickness (measured when installed) was 0.365”. Two years previous to the 0.30” measurement the thickness of the pipe was measured to be 0.31”. Determine the greatest corrosion rate, i.e., short or long term.

a. 0.0050 inches per year
b. 0.0065 inches per year
c. 0.0100 inches per year
d. 0.0130 inches per year

205. A seamless NPS 10 pipe, ASTM A106 Gr. B material, operates at 750 psi and degrees F. (maximum). The thickness of the pipe as determined by the last inspection is 0.30”. The pipe has been in service for 10 years. The original thickness (measured when installed) was 0.365”. Two years previous to the 0.30” measurement the thickness of the pipe was measured to be 0.31”. The next planned inspection is scheduled for 7 years. Using the worst corrosion rate (short or long term) determine what pressure the pipe will withstand at the end of its next inspection period?

a. 920 psi
b. 663 psi
c. 811 psi
d. 750 psi

API 570 PRACTICE QUESTIONS

ANSWER KEY

1. c. API 570, 1.1.1.
2. b. API 570, 1.1.2.
3. a. API 570, 1.1.3.
4. b. API 570, 1.2.1.
5. b. API 570, 1.2.1.
6. b. API 570, 4.3.4
7. b. API 570, 4.1
8. a. API 570, A.2.1
9. d. API 570, 5.1
10. d. API 570, 5.1
11. a. API 570, 5.3
12. b. API 570, 5.3.1
13. c. API 570, 5.3.1
14. a. API 570, 5.3.1
15. b. API 570, 5.3.1
16. a. API 570, 5.3.1
17. c. API 570, 5.3.1
18. c. API 570, 5.3.2
19. c. API 570, 5.3.2
20. d. API 570, 5.3.2
21. c. API 570, 5.3.3
22. c. API 570, 5.3.3
23. d. API 570, 5.3.3.1
24. c. API 570, 5.3.3.2
25. b. API 570, 5.3.4
26. d. API 570, 5.3.4
27. b. API 570, 5.3.5
28. b. API 570, 5.3.6
29. a. API 570, 5.3.6
30. c. API 570, 5.3.7
31. d. API 570, 5.3.7
32. d. API 570, 5.3
33. d. API 570, 5.3.8
34. a. API 570, 5.3.8
35. c. API 570, 5.3.9
36. b. API 570, 5.3.9
37. b. API 570, 5.3.9
38. a. API 570, 5.3.10
39. b. API 570, 5.3.10
40. b. API 570, 5.3.11
41. a. API 570, 5.3.12
42. d. API 570, 5.4
43. c. API 570, 5.4.1
44. c. API 570, 5.4.1
45. b. API 570, 5.4.2
46. b. API 570, 5.4.2
47. a. API 570, 5.4.3
48. b. API 570, 5.4.3
49. a. API 570, 5.4.3
50. d. API 570, 5.4.5
51. b. API 570, 5.5.1
52. b. API 570, 5.5.2
53. c. API 570, 5.5.2
54. c. API 570, 5.5.2
55. c. API 570, 5.5.2
56. b. API 570, 5.5.3
57. a. API 570, 5.5.3
58. b. API 570, 5.5.3
59. c. API 570, 5.5.3
60. c. API 570, 5.5.3
61. b. API 570, 5.6
62. d. API 570, 5.6
63. a. API 570, 5.6
64. d. API 570, 5.6

65. a. API 570, 5.7
66. a. API 570, 5.7
67. c. API 570, 5.7
68. d. API 570, 5.7
69. d. API 570, 5.7
70. b. API 570, 5.7
71. c. API 570, 5.7
72. d. API 570, 5.7
73. c. API 570, 5.7
74. d. API 570, 5.8
75. d. API 570, 5.9
76. c. API 570, 5.10
77. b. API 570, 5.10
78. d. API 570, 5.10
79. b. API 570, 5.11
80. c. API 570, 5.11
81. c. API 570, 5.11
82. b. API 570, 6.2
82. (1) a. API 570, 6.1
82. (2) c. API 570, 6.1
82. (3) a. API 570, 6.1
83. d. API 570, 6.1.1
84. d. API 570, 6.1.2
85. b. API 570, 6.2.3
86. b. API 570, 6.2
87. b. API 570, 6.2
88. a. API 570, 6.4
89. a. API 570, 6.4
90. c. API 570, 6.3
91. d. API 570, 6.4
92. c. API 570, 6.5.1
93. b. API 570, 6.6.2
94. a. API 570, 6.6.3
95. a. API 570, 7.1.1
96. a. API 570, 7.1.1
97. c. API 570, 7.1.1
98. b. API 570, 7.1.2
99. c. API 570, 7.1.3
100. a. API 570, 7.2
101. b. API 570, 7.3
102. b. API 570, 7.4
103. b. API 570, 7.4
104. c. API 570, 7.5
105. c. API 570, 7.6
106. b. API 570, 7.6
107. a. API 570, 8.1
108. b. API 570, 8.1.1
109. c. API 570, 8.1.1
110. c. API 570, 8.1.1
111. b. API 570, 8.1.1
112. d. API 570, 8.1.2
113. a. API 570, 8.1.2
114. c. API 570, 8.1.2
115. d. API 570, 8.1.3.1
116. a. API 570, 8.1.3.1
117. c. API 570, 8.1.3.1
118. d. API 570, 8.1.3.2
119. d. API 570, 8.1.4
120. b. API 570, 8.1.4
121. c. API 570, 8.1.4
122. d. API 570, 8.2
123. c. API 570, 8.2
124. a. API 570, 8.2.1
125. d. API 570, 8.2.1

126. c. API 570, 8.2.2.1
127. b. API 570, 8.2.2.2
128. d. API 570, 8.2.3
129. b. API 570, 8.2.3
130. c. API 570, 8.2.3
131. c. API 570, 8.2.3
132. b. API 570, 8.2.4
133. d. API 570, 8.2.5
134. d. API 570, 8.2.6
135. b. API 570, 8.2.6
136. b. API 570, 8.2.6
137. b. API 570, 8.2.6
138. a. API 570, 8.2.6
139. a. API 570, 8.3
140. c. API 570, SEC. 9
141. b. API 570, 9.1.1
142. c. API 570, 9.1.2
143. b. API 570, 9.1.3
144. a. API 570, 9.1.5
145. a. API 570, 9.1.6
146. b. API 570, 9.2.1
147. c. API 570, 9.2.2
148. b. API 570, 9.2.3
149. c. API 570, 9.2.4
150. a. API 570, 9.2.5
151. c. API 570, 9.2.6
152. d. API 570, 9.2.6
153. d. API 570, 9.2.6
154. b. API 570, 9.2.7
155. b. API 570, 9.2.7
156. d. API 570, 9.2.7
157. d. API 570, 9.2.7
158. a. API 570, 9.2.7
159. d. API 570, 9.3.1
160. c. API 570, 9.3.2 & 9.4
161. b. API 570, 3.1
162. d. API 570, 3.3
163. c. API 570, 3.4
164. c. API 570, 3.5
165. c. API 570, 3.6
166. b. API 570, 3.8
167. d. API 570, 3.9
168. d. API 570, 3.10
169. b. API 570, 3.11
170. b. API 570, 3.12
171. b. API 570, 3.13
172. a. API 570, 3.14
173. a. API 570, 3.15
174. c. API 570, 3.1
175. b. API 570, 3.44
176. c. API 570, 3.40
177. b. API 570, 3.46
178. a. API 570, APP. C
179. a. API 570, APP. C
180. b. API 570, APP. C
181. c. API 570, APP C

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182. d. API 570, 3.53
183. b. API 570, 7.4
184. a. API 570, 7.1 & 7.3
185. c. API 570, 3.51
186. b. API 570, APP C-2
187. d. B31.3, 328.5.4 (c)
188. a. B31.3, 304.1.1
189. c. B31.3, 304.1.1
190. a. B31.3, Table C-1
191. b. B31.3, 304.5.3
192. a. B31.3, 304.1.1
193. c. API 570, 7.1.1
194. d. API 570, 7.1.1
195. b. API 570, 7.1.1
196. d. API 570, 6.3
197. a. B31.3, 304.1.1
198. b. API 570, 7.1.1
199. b. API 570, 7.2
200. d. B31.3, 304.1.1
201. c. B31.3, 304.1.1
202. b. B31.3, 331.1
203. b. API 574, 11.2
204. b. API 570, 7.1 & 7.2
205. b. API 570, 7.1 & 7.2