

Standard Practice

Refinery Injection and Process Mix Points

This NACE International standard represents a consensus of those individual members who have reviewed this document, its scope, and provisions. Its acceptance does not in any respect preclude anyone, whether he or she has adopted the standard or not, from manufacturing, marketing, purchasing, or using products, processes, or procedures not in conformance with this standard. Nothing contained in this NACE standard is to be construed as granting any right, by implication or otherwise, to manufacture, sell, or use in connection with any method, apparatus, or product covered by letters patent, or as indemnifying or protecting anyone against liability for infringement of letters patent. This standard represents minimum requirements and should in no way be interpreted as a restriction on the use of better procedures or materials. Neither is this standard intended to apply in all cases relating to the subject. Unpredictable circumstances may negate the usefulness of this standard in specific instances. NACE assumes no responsibility for the interpretation or use of this standard by other parties and accepts responsibility for only those official NACE interpretations issued by NACE in accordance with its governing procedures and policies which preclude the issuance of interpretations by individual volunteers.

Users of this NACE standard are responsible for reviewing appropriate health, safety, environmental, and regulatory documents and for determining their applicability in relation to this standard prior to its use. This NACE standard may not necessarily address all potential health and safety problems or environmental hazards associated with the use of materials, equipment, and/or operations detailed or referred to within this standard. Users of this NACE standard are also responsible for establishing appropriate health, safety, and environmental protection practices, in consultation with appropriate regulatory authorities if necessary, to achieve compliance with any existing applicable regulatory requirements prior to the use of this standard.

CAUTIONARY NOTICE: NACE standards are subject to periodic review, and may be revised or withdrawn at any time in accordance with NACE technical committee procedures. NACE requires that action be taken to reaffirm, revise, or withdraw this standard no later than five years from the date of initial publication and subsequently from the date of each reaffirmation or revision. The user is cautioned to obtain the latest edition. Purchasers of NACE standards may receive current information on all standards and other NACE publications by contacting the NACE *FirstService* Department, 15835 Park Ten Place, Houston, TX 77084-5145 (telephone +1 281-228-6200).

Approved 2014-06-26
NACE International
15835 Park Ten Place
Houston, Texas 77084-5145
+1 281-228-6200

ISBN 1-57590-284-2
©2014, NACE International

Foreword

Corrosion at locations where two streams mix has caused significant failures in the petroleum refining industry over the years. This NACE standard addresses the unique nature of injection points and process mix points, in both design and inspection. This standard discusses typical material selection, corrosion concerns, and successful design and inspection practices used in petroleum refinery injection point and process mix point systems.

This standard was originally prepared as a technical committee report in 2001 by NACE Task Group (TG) T-8-21, "Refinery Additives Injection Facilities," administered by Group Committee T-8, "Petroleum Refining and Gas Processing." In 2014, TG 174 (formerly T-8-21) prepared this standard to replace the previous technical committee report NACE Publication 34101. TG 174 is administered by Specific Technology Group (STG) 34 (formerly Group Committee T-8), "Petroleum Refining and Gas Processing." This standard is issued by NACE under the auspices of STG 34.

In NACE standards, the terms *shall*, *must*, *should*, and *may* are used in accordance with the definitions of these terms in the *NACE Publications Style Manual*. The terms *shall* and *must* are used to state a requirement, and are considered mandatory. The term *should* is used to state something good and is recommended, but is not considered mandatory. The term *may* is used to state something considered optional.

NACE International Standard Practice

Refinery Injection and Process Mix Points

Contents

1. General	1
2. Definitions	1
3. Design Guidelines	2
4. Implications of Injection and Process Mix Points	6
5. Hardware Design	6
6. Injection and Mix Point Location	10
7. Guidelines for Typical Refinery System	11
8. Performance Verification and Monitoring	14
9. Inspection of Equipment	15
References	16
Appendix A: Variables Affecting Mixing/Dispersion (Nonmandatory)	17
Appendix B: Case Histories (Nonmandatory)	21
Appendix C: Sample Injection Point Data Sheet (Nonmandatory)	27
Appendix D: Hardware Design Philosophy (Nonmandatory)	28
Appendix E: Considerations for Typical Refinery System Injection Designs (Nonmandatory)	32
FIGURES	
Figure 1: Configurations of Injection Devices	9
Figure 2: Injection Device and Nozzle Orientations	9
Figure 3: Injection Nozzle Discharge Orientations	9
Figure A1: Flow Regimes in Horizontal Piping	18
Figure A2: Vertical Up-Flow Regimes	18
Figure A3: Baker Plot Prediction of Flow Regimes for Horizontal Two-Phase Flow	19
Figure A4: Hewitt and Roberts Two-Phase Up-Flow in Gas-Liquid Flow Streams in Vertical Piping. Regime Map	20
Figure A5: Change in Flow Regime as a Function of Inclination	20
Figure B1: Hydrodesulfurizing Unit Separator Overhead Piping Isometric	21
Figure B2: Atmospheric Crude Column Overhead Piping Isometric	22
Figure B3: Light Ends Recovery Piping Isometric	23
Figure B4: Location of Crack in Process Mix Point at Heat Exchanger Bypass	23
Figure B5a: Isometric of De-Ethanizer Line at Pipe Failure Location	24
Figure B5b: Failure Downstream from Intermittent Injection Point	25
Figure B5c: Failure at Extradors from Downstream Elbow	25
Figure D1: Chemical Dosing Alternatives	29
Figure D2: Retractable Quill Assembly	29
Figure D3: Hollow-Cone and Full-Cone Spray Distribution	30
Figure D4: Radial Sparger	31
TABLE	
Table E1: Guidelines for Wash Water Quality	36

Section 1: General

Injection points and process mix points for several typical refinery process streams are addressed in detail. The discussion of process mix points is limited to primary process streams, and considers only changes in temperature, pH, phase changes, and the concentration of corrosive species. Additional information is included in the Appendixes A through E (Nonmandatory).

Section 2: Definitions

Caustic Compounds or Caustic—caustic, or caustic soda, or more formally, sodium hydroxide is a strong ionic chemical base. Other bases, such as potassium hydroxide, also fall into the category of caustic compounds.

Carrier or Diluent—a nonreactive stream that is combined with an injected chemical (e.g., amine neutralizer) to increase the volume flow through an injection device, improving control, distribution, mixing, and/or reducing injection device fouling.

Drop Size Distribution—the size distribution of drops, typically expressed by the size vs. cumulative volume (in percent).

Chemical Injectant—process additive or other process stream that is added to a process stream in small quantities, for control of corrosion, fouling, pH, or other chemical property of a process stream. Wash water is also a chemical injectant, but is typically added in larger quantities than other process additives.

Injection Point—locations where chemicals, or process additives, are introduced into a process stream. Corrosion inhibitors, neutralizers, process antifoulants, desalter demulsifiers, hydrogen, oxygen scavengers, caustic, and water washes are most often recognized as requiring special attention during injection point design.

Mix Points—mix points are points of joining of process streams of differing composition and/or temperature where additional design attention, operating limits, and/or process monitoring are utilized to avoid damage mechanisms (e.g., corrosion). See also definition for Process Mix Point.

Mixing Quill/Quill—hardware, including piping that intrudes into the main process stream, designed to optimize distribution of the injectant into the process stream. The quill itself is a thin hollow probe designed to deliver an injectant into a pressurized receiving stream, promoting improved dispersion/absorption of the injectant into the receiving stream.

Process Mix Point—the locations where two process streams of differing chemical or physical (e.g., temperature, pressure, and phase) properties join at a piping tie-in.

Reynolds Numbers (Re)—dimensionless parameter used to characterize flow regimes, such as laminar flow, which occurs at low Re numbers where viscous forces are dominant, or turbulent flow, which occurs at high Re numbers where inertial forces are dominant. Software programs are available that facilitate calculating Re.

Shock Condensation—condensation of liquid phase out of a vapor stream as the result of mixing a lower-temperature stream with a higher-temperature vapor stream. When the resultant local temperature drops below the water or acid gas dew point of the combined stream, condensation may occur, which may result in localized or general metal loss.

Sparger—a perforated pipe designed to promote even distribution of gas in a liquid stream.

Spray Nozzle—a precision device that facilitates dispersion of liquid into a spray. Nozzles are used for three purposes: increase liquid surface area to enhance evaporation/dispersion/mass transfer; to distribute a liquid over a cross-sectional area; and/or to wet pipe walls downstream from the injection point.

Thermal Fatigue—a cracking mechanism caused by repeated thermal cycling.

Water Wash Injection—injection of water into process streams on a continuous or intermittent basis to: introduce water upstream from the salt deposition temperature, remove salt deposits that foul and/or can cause corrosion, or dilute a condensing stream to make it less corrosive.

Section 3: Design Guidelines

3.1 Process Considerations—Injection and process mix points are process tie-ins. They differ from other process tie-ins because they have the potential to compromise mechanical integrity. They typically meet one or more of the following criteria:

- (a) Mix two distinctly separate streams;
- (b) Promote chemical or physical reactions when mixing the constituents of two or more process streams;
- (c) Scrub or extract constituents of one stream by contact with another stream;
- (d) Heat or cool one process stream by direct contact with another stream (including flashing or quenching);
- (e) Adding chemical additives to a process stream to adjust pH or improve on process operations; or
- (f) Wetting internal surfaces of process equipment to inhibit corrosion.

3.1.1 During initial process design, injection points and process mix point systems (including fabrication details) shall be reviewed in detail. A thorough safety review (e.g., hazard and operability [HAZOP]) should be conducted. A data sheet should be generated for all injection points. A sample is provided in Appendix C. The owner shall ensure that injection system equipment is adequate and meets plant standards. It is also the owner's responsibility to ensure that mechanical integrity of the equipment be maintained.

3.1.2 Engineering design guidelines shall be based on successful industry and user experiences. Computational fluid dynamic (CFD) simulations of injection or process mix points may be used to improve understanding of the design's impact on system integrity.

3.1.3 Process simulation of refinery operating environments may be necessary to determine the impact of the mixing of the streams on variables important to the corrosiveness of the stream (e.g., mass flow, temperature, pressure drop, nozzle positioning and orientation, fluid type, and fluid density).

3.2 Continuous vs. Intermittent Water Wash Injection

3.2.1 When corrosion control is the primary consideration, continuous water injection shall be used. Continuous water wash in overhead lines has the advantage of requiring less operator interaction, continuously washing away corrosive agents, and avoiding wet/dry cycling in high corrosion potential zones. The disadvantage is that although water was injected to reduce the concentration of corrosive species, the system is now continuously wet, allowing corrosion, albeit at lower rates, to be continuous.

3.2.2 If fouling control is the only objective, wash water availability is limited, and where there is little risk of corrosion, intermittent injection rather than continuous injection may be sufficient. When process system pressure drop limitations exist, intermittent wash water injection may be used. The use of intermittent injections, though, must consider the potential impact of increased corrosion during the cycle of injection and for the potential build-up of corrosive salts and subsequent under-deposit corrosion.

3.2.3 When water is injected into a vapor stream, designs should ensure that sufficient liquid water remains after flashing to dilute corrosive species to a manageable level at the process maximum operating temperature. Typical targets are 25% of the injected water remaining liquid after the injection point.

3.3 Carrier or Diluent Fluids

3.3.1 If limiting the injectant chemical concentration is critical, or if increasing total volumetric flow of the injectant stream is required to obtain good dispersion, then a carrier (diluent) fluid shall be used.

3.3.2 Carrier fluids should be nonreactive and maintain sufficient phase stability within the injection device. Light gas oil, heavy naphtha, water, and steam have been used successfully for various applications. Reflux slip-streams often are used as carrier fluids for injection into overhead systems.

3.3.3 Controlled carrier fluid flow rates should be maintained to promote dispersion, to improve injection concentration control in the receiving stream, and to prevent problems such as excessive quenching, which can be caused by excessive carrier fluid flow. One method of doing this is to use a carrier pump that restricts the flow rate to within the control band of the injection pump.

3.3.4 Thermodynamic properties should be considered when choosing a carrier fluid. The temperature of the carrier fluid should not be cold enough to promote shock condensation. Additionally, if a carrier fluid flashes across a valve or nozzle, local process temperatures can be lowered, promoting local condensation. If water condenses, subsequent acid gas absorption can promote high corrosion rates.

3.3.5 Injection devices shall be sized to handle the increased throughput and pressure drop caused by the addition of carrier fluid.

3.3.6 Hydrocarbon carrier streams or steam should be used when the stream temperature is hotter than 150 °C (302 °F), and where the potential exists for enhanced corrosion/erosion as a result of an undiluted injectant.

3.4 Compatibility

3.4.1 The compatibility of the carrier fluid and the chemical injectant with the process stream shall be considered during design. While the chemical injectant may be soluble when fully dispersed in a process stream, it may be insoluble at the higher concentrations that occur at the injection point, and may promote fouling and/or corrosion.

3.4.2 If the carrier fluid or chemical injectant solubility is dependent on process stream variables, the piping configuration design should allow for the removal of accumulated carrier fluid/chemical injectant.

3.5 Flow Regime

3.5.1 Injection point and process mix point systems shall be designed to obtain the required mixing/dispersion. In systems in which the potential for significant damage has been identified, the design should utilize industry and company experience to assess the effect of changes in flow regime on mixing/dispersion. The rate of mixing depends on the flow regime at, and downstream from the injection/mix point, and is a function of process stream mass flow velocity, pipe orientation, the number of phases present, and the relative densities of the chemical injectant/carrier and receiving streams. These factors determine the flow regime, how quickly the combined stream comes to equilibrium, and where potential issues may occur. Flow regimes are defined and correlations that allow prediction of flow regimes for mixed gas-liquid streams are available. Refer to Appendix A.

3.6 Temperature Effects

3.6.1 Designers shall consider the impact of temperature changes that may occur as a result of the mixing of different streams.

3.6.2 To reduce the potential for thermal fatigue, thermal sleeves should be considered when mixing hot and cold streams with temperature differentials greater than 167 °C (300 °F). In corrosive environments, corrosion-assisted fatigue has been reported for temperature differentials less than 167 °C (300 °F). In these cases the potential for thermal fatigue should be investigated.

3.6.3 Temperature changes affect phase relationships, such as evaporation and condensation, and can determine the location and extent of corrosion damage. Under transient conditions, shock condensation may occur, even if the bulk temperature is above the water dew point.

3.6.4 When exothermic or endothermic reactions (e.g., heat of mixing) are expected, the design should be satisfactory at all expected temperatures.

3.6.5 Temperature changes can affect the mechanical properties and corrosion resistance of materials at process mix points, as well as changing the corrosiveness of the fluid. Temperature changes as a result of mixing hot and cold streams (e.g., temperature control bypass valves) should be considered.

3.6.6 The possibility of chemical injectant decomposition and/or polymerization at high temperatures should be considered. High-temperature process streams can promote thermal decomposition or polymerization of the chemical injectant reducing its effectiveness or increasing fouling potential.

3.7 Miscible and Immiscible Fluids

3.7.1 For liquid-liquid mixing of miscible fluids, the process design should maximize the volume ratio of the injectant stream to process stream, and the piping configuration should promote mixing. Dispersion and dissolution are time-dependent processes, and adequate dispersion may not be obtained until the mixed stream has moved 100 pipe diameters or more downstream.

3.7.2. Velocity should be maximized, or in-line mixers should be used to promote dispersion for immiscible streams. Immiscible streams may remain as separate phases in the mixed stream, or a new phase may form downstream from the injection or process mix point. The flow regime that develops in the multiphase mixed stream depends on the velocity of the stream, the relative amounts and densities of present phases, and the size and orientation of the line.

3.8 Mixing Zone Materials

3.8.1 Materials selection for the mixing zone shall consider local erosion, erosion-corrosion, and corrosion rates that may be strongly influenced by flow regime and turbulence. The likelihood of liquid impingement at downstream elbows and tees in the mixing zone shall be considered. The potential for flow-induced pressure fluctuations and vibrations should be considered in the design of the injection or process mix point.

3.9 Causing a Chemical or Physical Reaction

For mixing systems intended to promote chemical or physical reactions, adequate residence time should be provided to facilitate complete mixing. Use of a purpose-designed mixing device or sufficient downstream piping should be considered.

3.10 Heating or Cooling (Flashing or Quenching)

3.10.1 Material selection in systems designed to quench the process stream, (e.g., hydrogen quench in hydroprocessing) should take into account materials degradation of chemical injection/mix point system components as a result of conduction of heat back into the injectant line. In the case of sulfidic corrosion, refer to API⁽¹⁾ 939-C.¹ In the case of high-temperature hydrogen attack (HTHA), refer to API 941.²

3.10.2 Injectant chemical concentration can increase in systems where flashing occurs. Designs should verify that adequate solvent is available to inhibit concentration to higher levels where damage may occur as a result of injectant chemical concentration (e.g., NaOH in scrubber systems).

3.11 Wetting of Piping Surfaces

3.11.1 Where wetting is required, process designs should provide stable flow regime to promote full dispersion of injectant streams, and to assure contact with the pipe wall. In gas-liquid mixed streams, annular, churn, bubble, and froth flow favor continuous wetting of the walls by the liquid phase. Stratified and wavy flow should be avoided when wetting is the intent because these flow regimes do not allow the liquid phase to wet all surfaces.

3.11.2 Wetting agents may be added to refinery process streams, promoting interaction between corrosion inhibitors and filming agents.

3.11.3 Co-current injection should be used when wetting is required, as resultant larger droplet sizes promote more effective wetting.

3.12 Design Considerations to Assure Mechanical Integrity

To verify the physical condition and/or for repairing injection and mix point equipment and hardware, appropriate permanent access should be provided for all retractable systems. Other types of injection points should be easily accessible with temporary equipment (e.g., "manlifts" or scaffolding).

3.13 Alloying Considerations

3.13.1 Materials of construction for the injection/mix devices should be compatible with the injectant, the process stream, and the combined stream during steady state operation and at transient conditions that may occur during mixing, start-up/shut-down.

⁽¹⁾ American Petroleum Institute (API), 1220 L St. NW, Washington, DC 20001.

3.13.2 To maintain the availability and reduce the risk of poor performance, a more corrosion-resistant alloy for the overall injection and process mix point systems shall be considered. When wet H₂S environments are anticipated, the requirements of NACE MR0103³ shall be considered.

3.13.3 When process conditions change at an injection point or process mix point, the materials used should be reevaluated.

3.13.4 Dissimilar metal welds⁽²⁾ should be avoided when possible, especially in regions where electrochemical corrosion occurs. In most cases, where transitions between two crystallographically different materials (e.g., austenite/ferrite) are required, mechanical joints (e.g., flanges) are preferred. If dissimilar welds are used, the recommended practices outlined in Section 6.2 of API 582⁴ shall be adopted.

3.14 General Factors Impacting Corrosion in Injection and Mixing Systems

3.14.1 If the separate streams at chemical injection or process mixing points have large temperature differences, or react exothermically (heat of mixing), the materials of construction should be corrosion resistant at all anticipated temperatures.

3.14.2 Increased corrosiveness can occur when either the chemical injectant or main process streams are heated. The entire operating temperature envelope should be considered when assessing the thermal stability and corrosiveness of injection chemicals.

3.14.3 Corrosion-resistant materials should be used to fabricate injection point/process mix point systems when temperature decreases resulting from injection/mixing of cold streams or by evaporation of injectant/carrier can promote localized condensation of corrosive species.

3.14.4 Process designs should verify that the gas stream Reynolds number (Re) at the point of liquid injection should be > 4,000 to promote turbulence and better dispersion, reducing the possibility of localized high concentrations of injectant, and thus corrosion at the pipe wall. However, values of Re high enough to promote impingement/erosion and erosion-corrosion should be avoided.

3.14.5 Injection device material selection should consider fouling that can occur during “not normally flowing” (NNF) conditions.

3.14.6 Intermittent injection systems, including pumps, flow lines, valves, and injection devices should have provisions for purging potentially corrosive and/or fouling compounds before shutdown.

3.14.7 Injection systems shall be designed to prevent injectant freezing or thickening of injection fluids in winter climates. Piping for injection systems is commonly heat traced. Mixing tanks and pumps for chemical injectants should be kept in a heated building.

3.14.8 When used, heat tracing/insulation design shall consider temperature sensitive degradation and polymerization mechanisms of the chemical injectant, higher corrosion rates, and cracking mechanisms (e.g., heat tracing impact on carbon steel in caustic systems). Provisions should be made to prevent overheating injectant chemicals (such as filming inhibitors) left in piping during periods of nonuse (including shutdowns). Options may include using stand-offs, turning off heat tracing, and utilizing temperature control.

3.14.9 Injectant supply piping including gaskets, instrumentation, and valves should be fabricated using materials compatible with the chemical injectant under all operating conditions.

3.15 Pressure Boundary Components—Injection Points

3.15.1 Pressure boundary components associated with refinery injection point systems shall be designed to comply with the piping design and fabrication code (e.g., ASME⁽³⁾ B31.3⁵) in the appropriate jurisdiction.

3.15.2 In accordance with API 570,⁶ “Injection Point Inspection” section, the injection point systems shall include:

⁽²⁾ The term *dissimilar metal weld* is intended to describe a weld that joins metals with two distinctly different crystallographic structures (e.g., 300 series SS [γ] and carbon steel [α]). Welds between different grades of 300 series stainless steels or between carbon and low-alloy steels are not included in the scope of this definition.

⁽³⁾ ASME International (ASME), Three Park Ave., New York, NY 10016-5990.

- (a) upstream process piping equivalent to 300 mm (12 in) or three times the piping diameter, whichever is greater; and
- (b) for downstream piping, the second change in flow direction past the injection point, or 7.6 m (25 ft) beyond the first change in flow direction, whichever is less. In some instances it may occur at the next piece of pressure equipment.
- (c) The injection point system shall also include:
 - the injection device (e.g., quill) chemical injectant piping back to the first upstream block valve; and
 - other areas where corrosion/erosion has been identified as being associated with an injection point.

3.15.3 Materials of construction for pressure boundary components shall consider corrosion conditions promoted by changes in flow regime and increase/decrease in local temperatures anticipated for all design cases, including start-ups and shut-downs.

3.15.4 Injection devices should be oriented to minimize coalescence of the small injectant droplets as a result of gravity.

3.15.5 Piping designs should promote aerosol or bubble flow. Injection into annular or stratified flow regimes should only be considered after a detailed analysis, including computational fluid dynamics, has been undertaken. Injection streams with intermittent flow regimes, either plug flow or slug flow, should be avoided. These considerations may be applied to piping modifications depending on the user's needs.

3.16 Pressure Boundary Components—Process Mix Points

3.16.1 A process mix point shall include appropriate upstream and downstream piping from the mix point to the effective boundary of the respective damage mechanism. This may be local to the mix point as in the case of thermal fatigue. However, where corrosion is the primary concern, the extent may expand to the limits associated with injection points (see Paragraph 3.15.2).

3.16.2 Materials of construction for pressure boundary components shall consider corrosion conditions promoted by changes in flow regime and local temperature increases/decreases anticipated for all design cases, including start-ups and shut-downs.

Section 4: Implications of Injection and Process Mix Points

4.1 Design of refinery injection systems and process mix points shall involve the same detailed engineering practices associated with any other process system. Some unsuccessful designs (case histories) are described in Appendix B. Successful designs have considered the following:

4.1.1 Temperature and Material Specification Breaks

4.1.1.1 Temperature breaks should occur in materials that can accommodate the expected temperatures at that location.

4.1.1.2 A temperature increase caused by the conduction of heat and/or a change in operating temperature can impact the corrosion resistance of materials at a piping materials change (specification break), and shall be considered in the piping design.

4.1.1.3 Material specification changes may be made with mechanical joints (i.e., flanges) or dissimilar welds. The design shall consider the implications of either method including leak potential, thermal design, local degradation, and future inspection requirements.

Section 5: Hardware Design

5.1 General

5.1.1 Injection device designs may include piping tees, quills, spray nozzles, and/or static mixers. Injection devices range in configuration from simple (pipe nipples) to the relatively complex (atomizing spray nozzles). (Refer to Figure 1 for diagram.) The choice of configuration depends on the desired result, and shall be determined on a case-by-case basis.

5.1.2 Designs shall be engineered to meet the specific process requirement (e.g., distribution, scrubbing, quenching).

5.1.3 Injection system designs should be consistent with the criticality of the application, including reliability safeguards (e.g., redundancy, retractable quills, filters, etc.).

5.1.4 Continuous and intermittent injection systems shall include a double block and bleed arrangement or other positive shut-off system to mitigate leakage of chemical injectant into the process when the process or injectant system is out of service/not flowing, and when leakage is deemed detrimental to the integrity of the system.

5.1.5 Main process lines containing nozzles and/or injection devices should be configured to be self-draining, without pockets and dead legs, mitigating possible accumulation of liquids/solids that can cause plugging or corrosion. Piping branches of tees should be oriented in the vertical *down* position. If this is not possible, the branch should be in the horizontal plane. Vertical *up* orientations should be avoided (Figure 2). Piping designs should include separator vessels when carry-over or condensation liquid is anticipated.

5.1.6 Match marking or other precautions shall be used to assure that injection devices are installed with the correct orientation, and that the proper orientation can be verified visually without disassembly. Flow direction arrow(s) for the process stream and the injection device stream direction should be clearly marked on the exterior portion of the flange. Retractable injection devices should include indicator marks that verify full retraction, insertion, and orientation.

5.1.7 Backflow protection shall be provided for on all injectant streams in injection point systems.

5.1.8 Injection devices with reduced opening size should be protected from plugging by filters in injectant supply lines. Filter screen mesh should be sized in accordance with the maximum free passage diameter opening of the nozzle.

5.1.9 Fixed injection devices should be used in high-pressure systems where potential leakage of the packing gland associated with retractable designs are a concern. These devices are most commonly used when the fluids are clean, and the service has a history of reliable operation.

5.2 Injection Devices

5.2.1 Tee Connections

5.2.1.1 Tee connections are the simplest injection devices, and should only be used to combine streams where corrosion, as a result of large temperature changes (e.g., heat of mixing, Joule-Thompson cooling), and thermal fatigue are not a concern.

5.2.1.2 Injection through tee connections should only be considered when downstream pipe runs or equipment provide adequate residence time, or injection at pump inlets is possible.

5.2.2 Quills

5.2.2.1 Quills should discharge co-currently into the center of the receiving stream to enhance dispersion and prevent contact of undiluted injectant with the pipe wall. Quills can affect the process stream by creating eddies, and while the turbulence created has typically been viewed as beneficial (promoting mixing), excessive turbulence can promote premature failure as a result of fatigue or erosion.

5.2.2.2 Quill designs shall include flow calculations to determine the natural frequency and whether fatigue is an issue.

5.2.2.3 Quills with beveled ends should be considered, as they promote better dispersion and mitigate potential corrosion or fouling caused by concentrating chemical injectants at the pressure boundary. When beveled, the angle should range from 30° to 45°. The longer end of the quill should be slotted to serve as the central point of dispersion. Quills with slotted ends enhance dispersion of the injectant. When used, the slot thickness should range between 2 to 3 mm (0.08 to 0.11 in) in width, and 10 to 13 mm (0.4 to 0.5 in) in length.

5.2.2.4 Retractable injection devices, normally sealed in a packing gland, can be advantageous in situations in which fouling of the injection device may occur during service (Figure D2). However, the disadvantages of retractable injection devices are the increased potential for leaks during insertion, operation (especially in hydrogen service), and removal, and the potential for incorrect insertion.

5.2.2.5 For gaskets and packing glands, graphitic materials (and fluorocarbons where fire resistance is not a consideration) should be considered, as their track record in preventing loss of containment is good.

5.2.2.6 Retractable quill designs shall include retraction stops and a protective blow-out device (e.g., chains).

5.2.2.7 When the pipe orientation is horizontal, a fully inserted quill should penetrate at least 150 mm (6 in) from the inboard pipe wall or to the centerline, whichever is less. In a vertical line, the quill should be inserted to the centerline.

5.2.2.8 Retractable quill isolation valves shall be clearly labeled, indicating that the quill passes through the valve, and that closure of the valve when the quill is not retracted results in the inability to remove the quill, damage to the quill, and/or increases the possibility of leaks when removed.

5.2.2.9 A thorough design review shall be undertaken when upgrading a pipe tee to a quill injection as this may not be sufficient to reduce localized corrosion problems.

5.2.3 Spray Nozzles

5.2.3.1 Spray nozzles should be considered for injecting liquids into gas streams or when the injectant is required to coat/wet the pipe wall. Spray nozzles are used to more rapidly disperse the injectant stream and increase its contact area with the receiving stream, promoting quick mixing, reaction, or evaporation. Commercially available designs provide a wide variety of spray patterns (e.g., full cone, hollow cone, fan, etc.), some of which are shown in Figures D3a through D3d in Appendix D.

5.2.3.2 Co-current injection is suggested when wetting is the desired result. For most applications, co-current injection with a full cone spray nozzle should be used.

5.2.3.3 Counter-current injection (Figure 3b) with hollow cone spray may be used when an increased spray zone is desired.

5.2.3.4 Cross-flow injection should be avoided because it results in impingement on the pressure boundary wall. Upgrading the material of construction or installation of a liner should be considered when cross-current injection cannot be avoided (Figure 3c).

5.2.3.5 Impingement can also occur when injection is too close to a change in direction (Figure 3d).

5.2.3.6 Selection of the spray nozzles in wash water systems shall consider the properties of the water and process stream, the pressure drop across the spray nozzle, and the flow and pressure drop ranges over which the nozzle is designed to operate.

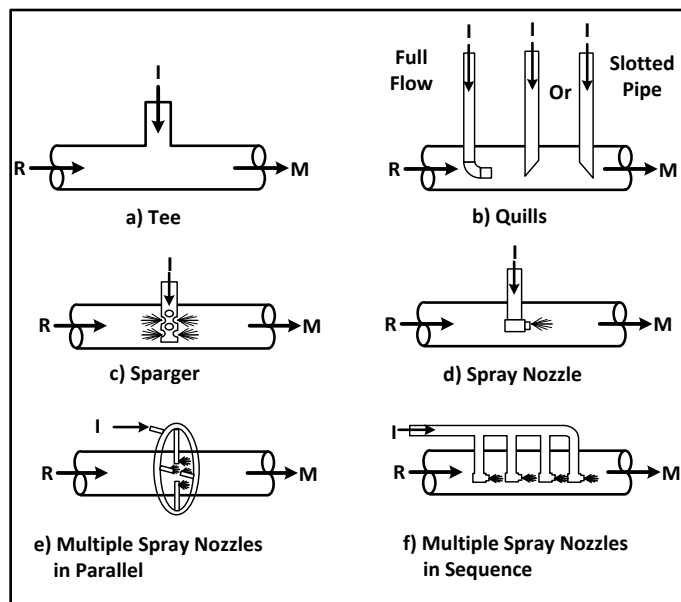
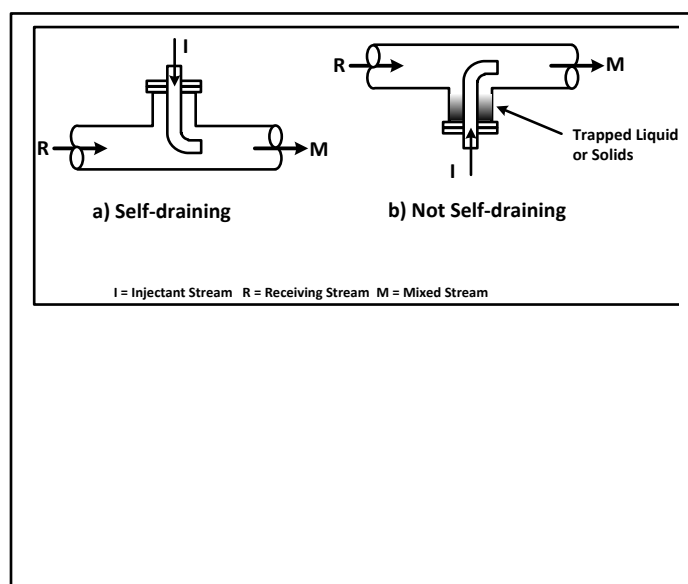


Figure 1: Configurations of Injection Devices



I = Injectant, R = receiving Stream, M = Mixed Stream

Figure 2: Injection Device and Nozzle Orientations

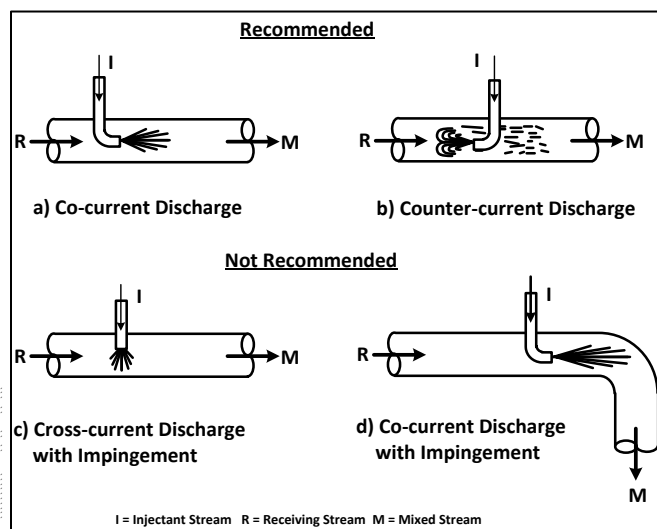


Figure 3: Injection Nozzle Discharge Orientations

5.2.4 Thermal Sleeves

5.2.4.1 Thermal sleeves should provide an adequate “gap” between the liner (thermal barrier) and the pipe to protect the pressure boundary.

5.2.4.2 Thermal sleeve designs should consider thermal fluctuations upstream and downstream from the mix point and, depending on the system, may require detailed design simulation (e.g., computational fluid dynamics, finite element analysis).

5.2.4.3 Thermal sleeve design shall consider trapped fluids/solids in the annular gap, and include an appropriate materials selection.

5.2.4.4 When corrosion mechanisms are sensitive to wall shear stress (flow turbulence), high alloy piping, a high-alloy liner, or a corrosion-resistant overlay shall be used.

5.2.5 Static Mixer

5.2.5.1 If good mixing is essential, a static mixing element should be installed downstream from the injection point.

5.2.5.2 In fouling services, provisions shall be made to permit cleaning the mixer without shutting down the unit. The static mixer should be fabricated from corrosion-resistant alloys.

5.2.6 Tanks

5.2.6.1 Storage of chemical injectants may require tankage. Unpressurized chemical storage tanks (or temporary totes) should be vented to the atmosphere to allow vapor displacement as a result of filling and emptying, and preventing pressure increases or decreases as temperature and atmospheric pressure change. Vents should be configured to prevent rainwater from getting into the tank.

5.2.6.2 If the chemical injectant contains a volatile organic compound, or is reactive in the air, tanks should be blanketed with inert gas.

5.2.6.3 If the tank contains concentrated acids, the tank should be blanketed with an inert gas or use inline desiccant traps to inhibit the ingress of moisture from the atmosphere. Localized dilution of concentrated acids can promote high corrosion rates. If a desiccant system is used, the regular change-out of the desiccant should be included in the refinery maintenance program.

5.2.6.4 Chemical tanks shall be properly labeled, identifying the chemical composition of tank contents and identifying hazards associated with exposure to the liquid inventory.

5.2.6.5 Tanks shall be included in a mechanical integrity management program. Local laws and regulations covering tank design and spill containment shall be adhered to.

5.2.6.6 Spill containment requirements also apply to totes.

5.2.6.7 When a dilution step is required, either a separate charge tank or in-line dilution system shall be used. See Appendix D for examples.

5.2.6.8 Tanks shall be compatible with fluid being stored at the expected storage conditions. Atmospheric temperature fluctuations (once-in-a-decade highs) can be sufficient to cause damage issues with polymer tanks.

Section 6: Injection and Mix Point Location

6.1 General

6.1.1 Several selection criteria (process, mechanical, accessibility for inspection and maintenance, and economy) should be considered when the injection or process mix point location is chosen. As a minimum, the following two factors should be considered in the selection of injection or mix point locations: mixing time, reactivity/corrosiveness of the chemical injectant, process stream, and the mixed stream. Wetting is a factor isolated to injection points only.

6.1.1.1 When mixing is the intent or when nondispersed, concentrated injectants are corrosive, the distance to the next injection point, elbow, valve, or process equipment should be maximized.

6.1.1.2 When wetting efficiency is the main concern, the injection device should be positioned close to the target components. Positioning injection devices farther upstream than necessary promotes coalescence of injected spray drops, reducing dispersion, and should be avoided.

6.1.1.3 Injection devices for corrosion control should be located upstream from where high corrosion rates are expected. If this is not possible, the section upstream from the injection device may require material upgrade. A cost benefit (or life-cycle cost) analysis should be performed to identify the best option.

6.2 Piping Configuration

6.2.1 After the injection point or mix point location has been determined, the exact piping configuration should be selected.

6.2.2 Chemical injection points should be installed in a straight run of pipe, instead of elbows, tees, reducers, or other pipe fittings. Straight pipe runs promote easier and more consistent mixing, as well as more repeatable results.

6.2.3 Distance between the injection or mix point location and the next change in direction or pipe components (valves, thermowells, etc.) should be maximized. Downstream changes in direction is a critical design variable. To the extent practical, the local flow regime caused by upstream piping configuration should also be considered.

6.2.4 Injection point locations should provide access to the entire pipe circumference, and also provide enough room for inspection devices (e.g., automatic ultrasonic testing [UT] crawlers/probes). The location should also allow safe access for inspection personnel.

6.3 Elbows/Changes in Direction

6.3.1 If concentrated chemical injectants can be corrosive and installation of an injection/mix point at a pipe fitting/elbow is unavoidable, the materials of construction should be critically reviewed, including the elbow/pipe fitting, injection quill, injectant pipe branch, immediate downstream piping, valves, and associated instrumentation. Injection into a pipe fitting/elbow can increase the potential for accelerated corrosion as the result of turbulence and unpredictable flow patterns. Inspection at elbows is often less effective than in a straight run of pipe.

6.3.2 In gas injection systems (e.g., steam into a fired heater pass), where gas is injected into an elbow, the injectant flow should be directed into the center of the flowing stream.

6.4 Pump Suction

6.4.1 Injection points in pump suction piping may be used when mixing is the desired end result, and the fluids involved are not corrosive, or when pumps with corrosion-resistant materials are used. Injection into pump suction lines promote more rapid dispersion than could be produced by turbulent flow in downstream piping alone, and eliminates the need for an in-line static mixer or a more costly design (quill or spray nozzle) design.

Section 7: Guidelines for Typical Refinery System

Detailed practices that are typical of injection and mix points in petroleum refineries can be found in Appendix E, "Considerations for Typical Refinery System Injection Designs."

7.1 Caustic Injection for Overhead Chloride Control

7.1.1 Purpose

(a) Caustic converts magnesium and calcium chlorides to sodium chloride, which is more difficult to hydrolyze. This limits the net amount of HCl that can condense in the crude column overhead system.

(b) Caustic injection systems (including associated process piping) should be designed to avoid the risk of caustic gouging, caustic embrittlement, increased fouling, and/or effects on downstream unit operation and product quality. Important parameters include caustic concentration, using slip streams, materials, and post-weld heat treatments. NACE SP0403⁷ can provide direction to avoid caustic cracking.

(c) Dilute caustic is typically injected into the crude oil downstream from the desalter vessels to inhibit the formation of emulsions, and downstream from the crude preheat train to prevent fouling.

7.2 Crude Overhead Injections—Neutralizer Injection

7.2.1 Purpose

(a) Addition of neutralizers into preflash and atmospheric tower overhead systems is used to control pH of condensed water and reduce corrosion rates.

(b) Neutralizer injection maintains condensate pH within a specified range at the accumulator.

(c) The pH control range varies based on the type of neutralizer used and the type and concentration of acidic compounds present. Most applications control the pH of water in the overhead accumulator water to values greater than 5.0 to limit acid corrosion. An upper pH limit of 7 is typically imposed to prevent overdosing with amine, and to inhibit amine salt fouling.

(d) The neutralizer is typically injected directly into column vapor overhead streams, into reflux slip streams, or into wash water or dilution water lines at the top of the column. Steam is sometimes used to atomize the neutralizer.

7.2.2 Type of Neutralizer

7.2.2.1 Ammonia (NH_3) or a blend of organo-amine neutralizers are used to neutralize the acidic compounds present in tower overhead condensing systems.

7.2.2.2 Aqueous ammonia provides the ease of controlling liquid dosage by positive displacement pumps compared to using gaseous ammonia flow control components.

7.2.2.3 When a neutralizer is selected, the overhead system design, especially wash water/no wash water, temperature, as well as dew point pH control, and salt-forming tendencies, should be considered. Potential downstream and recycle effects should also be understood.

7.3 Crude Overhead Injections—Filming Corrosion Inhibitors

7.3.1 Organic filming corrosion inhibitors (sometimes called filmers) are injected into tower overhead systems to provide corrosion protection by forming a protective film on the metal surface.

7.3.2 Filming inhibitors are typically nonvolatile, high-molecular-weight heterocyclic nitrogen compounds injected in conjunction with a carrier stream. Because the goal of a filmer is to wet the pipe walls, the injection device should promote atomization.

7.4 Crude Unit Overhead Water Wash

7.4.1 Purpose

- (a) To scrub salt-forming compounds from preflash and atmospheric tower overhead vapors;
- (b) To wash away salts that may have already deposited; and
- (c) To introduce water ahead of the naturally occurring water dew point, thereby limiting pH reduction as a result of condensation.

7.4.2 In water wash systems, water should be injected ahead of the location where corrosion is likely to occur.

7.4.3 Availability and quality of water used should be carefully evaluated. Typical sources are recirculated condensate from the atmospheric tower overhead drum, stripped sour water, boiler feed water, or other sources of condensate. Because dissolved oxygen can promote high corrosion rates, wash water should come from a deoxygenated source.

7.4.4 Adequate water should be injected to ensure that 25% of the water remains liquid after injection and subsequent vaporization.

7.4.5 If facility constraints inhibit the proper design and/or maintenance of the water wash system, not using a water wash should be considered, because a poorly designed and/or poorly maintained system can exacerbate corrosion problems.

7.5 Wash Water in Hydrocracker/Hydrodesulfurizer Reactor Effluent Streams

7.5.1 Water wash injection is used in hydrocracker and hydrodesulfurizer reactor effluent systems to prevent ammonium salt deposition, and dilute salt concentrations in the aqueous phase to reduce the corrosion. These salts are formed by the reaction of vapor phase ammonia (NH_3) with vapor phase hydrogen chloride (HCl) and/or hydrogen sulfide (H_2S). Reaction products ammonium chloride (NH_4Cl) and ammonium bisulfide (NH_4HS) can desublimates from the vapor phase to a solid

phase at temperatures below the “salt deposition temperature.” For other measures to control corrosion in hydroprocessing unit reactor effluent systems see API 932.⁸

7.5.2 Water should be injected before the location where the reactor effluent cools to the salt-deposition temperature.

7.5.3 Minimum required wash water flow rate should be that required to ensure that adequate free water is present at the injection point or that required to control ammonium bisulfide concentration to acceptable levels, whichever is greater. Without adequate water injection, ammonia salts can deposit on cooler piping surfaces (e.g., uninsulated pipe spools) and exchanger surfaces resulting in increased corrosion, pressure drop, and loss of heat transfer. This standard covers only the water wash injection system. Guidance in obtaining the minimum required wash water rate can be found in Appendix E, Paragraph E6.1.2.

7.5.4 The choice of intermittent or continuous water wash should consider the amount of water required in accordance with Paragraph 7.5.3, the system capacity for storing/removing water, and the ability to sustain that wash water rate.

7.5.5 The evaluation of the water source should consider the same precautions stated in Paragraph 7.4.3.

7.6 Polysulfide Injection in Fluidized Catalytic Cracking (FCC) and Delayed Coking Units (DCU) Systems

7.6.1 Purpose

(a) Addition of ammonium polysulfide (APS) into FCC and DCU overhead systems can be used to control cyanide concentration, thus mitigating corrosion of downstream equipment.

(b) These overhead systems contain O₂, NH₃, H₂S, HCN, and organic acid contaminants of varying concentrations.

(c) Most of these contaminants can be removed with adequate water washing of the process streams. APS is often added to react with the CN⁻ dissolved in the water to prevent cracking as a result of wet H₂S in the equipment and piping.

(d) APS should be injected with a wash water carrier. Wash water pH should be controlled to maintain APS stability. The temperature of the APS should be controlled to avoid freezing and thermal degradation.

7.7 Injection of Steam into Hydrocarbon Streams

7.7.1 Steam is used for many varied applications in refineries, including the following: an aid for separation in fractionation, a process feed in hydrogen reformer units, to increase hydrocarbon velocity, to control dew point in overhead systems, a carrier for process chemicals, to remove and/or dilute contaminants, to create vacuum, to fluidized catalyst. Steam pressures used are dependent on the process, and may vary from 207 kPa to 4,137 kPa (30 psig to 600 psig).

7.7.2 Steam injected into hot hydrocarbon streams should be superheated to prevent flashing of condensed water.

7.8 Chlorine into Catalytic Regeneration Systems

7.8.1 In the catalytic reforming and isomerization process, chloride must be adsorbed on the catalyst to produce the desired reactions. In order to accomplish this, HCl or organic chlorides are added to the hydrocarbon and hydrogen feed. Because chlorides are being continuously consumed in the process, they need to be continuously replenished.

7.8.2 Injection rates of the organo-chloride throughout all phases of operation need to be considered to assess HCl in the injection device, and whether corrosion is occurring as a result of HCl.

7.8.3 Injection into hot systems shall consider the high-temperature corrosiveness of the injections and should consider appropriate alloying of the injection system.

7.9 Hydrogen Mixing and Hydrogen Quench Systems

7.9.1 Purpose—Hydrogen (H₂) injection is typical in refinery hydroprocessing units such as catalytic reforming units, hydrocrackers, and hydrotreating units. The hydrogen is used for various purposes.

(a) In these units, H₂ is mixed with hot hydrocarbon streams before flowing through a reactor catalyst bed, promoting various high-temperature reactions, such as reforming, hydrocracking, desulfurization, and denitrification.

(b) Hydrotreating and hydrocracking are exothermic, and require H₂ as a quench either between reactor beds or between reactors.

7.9.2 H₂ mixing shall consider the requirements for materials resistance to HTHA and thermal fatigue.

7.10 Process Mix points

7.10.1 Purpose/Overview—As a result of a history of localized corrosion and thermal fatigue cracking, process mix points are an important consideration in refinery piping design. Corrosion rates can increase when local temperatures increase as a result of the lack of mixing; local temperatures are decreased resulting in shock condensation, or when streams containing reactants combine to form corrosives (i.e., water and chlorides). Mechanical damage (fatigue cracks) can occur when thermal fluctuations promote alternating thermal strains.

Process Mix Points include:

- Temperature control bypasses (around heat exchanger bypasses);
- Dry stream containing chlorides mixing with a wet stream; and
- Process streams with differential temperatures greater than 167 °C (300 °F).

7.10.2 The same considerations for injection point design should be applied to process mix points.

Section 8: Performance Verification and Monitoring

8.1 Process Stream Monitoring and Analysis

8.1.1 Injection system performance should be monitored either directly or remotely during service to assure that it is achieving its process objective and not adversely affecting the process or equipment.

8.1.2 Process stream monitoring and analysis protocol should be established and continuously monitored by operations to achieve the intended purpose of the injection and mixing, as well as to assure the integrity of the system. Minimum and maximum limits, their criticality (either as critical, standard, or target), and a prescribed response plan should be established for each parameter.

8.1.3 Receiving stream temperature, pressure, and flow rate should be monitored, as these parameters directly affect the physical state and chemical composition at the injection/mix point.

8.1.4 Depending on the specific objective of injection/mix point, process simulation and/or sampling/analysis of the combined stream may be required to determine dew point and concentration of corrosives (HCl, NH₃, H₂S).

8.1.5 The following chemical analysis should be considered for water injections: dissolved oxygen, pH, total suspended solids (TSS), hardness (and/or alkalinity), metals (e.g., iron, chromium, etc.), and contaminant concentration (e.g., chloride, ammonia, etc.).

8.1.6 For tower overhead water washes, the combined effluent streams should be analyzed to provide an indicator of system performance. Examples include sour water concentration in separator vessel boots, and amount of water (saturated or entrained) in separator vessel overheads.

8.1.7 Injectant stream flow rate is a key parameter and shall be monitored and controlled. In split injection systems, individual flows should be monitored.

8.1.8 Carrier stream temperature and flow rate shall be monitored and controlled if shock condensation could promote corrosion and/or fatigue.

8.1.9 Chemical injectant flow rate shall be monitored and controlled.

8.1.10 In tower overhead water wash systems, both fresh make-up and recycle water flow rates should be monitored and controlled separately. The practice of using fresh make-up and assuming recycle volume by measuring outgoing water should not be relied on.

8.1.11 Temperatures downstream from the injection device should be monitored in water wash systems, especially if there are multiple parallel injections, to assure equal distribution of the injectant.

8.1.12 Pressure differentials across spray nozzles and other mixing devices (e.g., static mixer) should be monitored to assure proper spray pattern and mixing efficiency, and to indicate the potential of fouling in or erosion of the mixing device.

8.1.13 Temperature should be monitored in systems where injection/mix point can cause significant temperature change.

8.1.14 In tower overhead water wash applications, effluent water flow rate should be monitored to allow a water mass balance to be conducted.

8.1.15 Flow meters or differential pressure gauges should be used to monitor flow rates. Comparisons with initial flow rates can be used to indicate deterioration in pump performance.

8.2 Online Corrosion Monitoring

8.2.1 Online monitoring of some degradation mechanisms may also be used to complement inspection, but should not be used in place of inspection.

8.2.2 Corrosion coupons (sacrificial coupons), online electrical probes, hydrogen flux monitoring, or other corrosion monitoring technologies may be used, where possible, to monitor corrosiveness of the process stream. The location of monitoring probes is critical, and should be considered carefully during the system design.

Section 9: Inspection of Equipment

9.1 Inspection of Pressure Boundaries Associated with Injection and Process Mix Points

9.1.1 Refinery injection systems should be inspected on a regular basis. The inspection should include the components listed in Paragraph 3.15.2.

9.1.1.1 As a minimum, injection point inspection should be conducted to detect corrosion (general and localized) as well as unique problems associated with some refinery injections. Inspection of injection points should be in accordance with API 570 recommendations because of the potential susceptibility to accelerated or localized corrosion.

9.1.2 Mix points should be evaluated for susceptibility of degradation, including corrosion, HTHA, thermal or mechanical fatigue, sulfide stress cracking (SSC), etc. If mix points are identified to have potential degradation issues, inspections should be performed in a manner similar to some or all of the components listed in Paragraph 3.16.1, and those required for injection points in accordance with API 570 requirements.

9.1.3 If localized corrosion is expected, radiography or automated ultrasonic techniques, such as A-scan, B-scan, and C-scan should be used. Localized corrosion can easily be missed when manual ultrasonic thickness measurements are performed.

9.2 Injection Quill and Spray Nozzle Inspection

9.2.1 Injection quills and spray nozzles should be visually inspected periodically for fatigue damage and loosening of joints. Penetrant testing should be used to identify cracks in components that are susceptible to fatigue.

9.2.2 Injection quills should be visually inspected regularly for fouling and corrosion. In systems where configuration allows, radiography may be used to determine the condition, but this inspection should not be considered an alternative to visual inspection when the injection device is taken out of the process piping.

9.2.3 Spray nozzles should be visually inspected for wear (corrosion/erosion) of the nozzle orifice. In hollow-cone spray nozzles, wear often results in inhomogeneous spray patterns, often showing heavy streak patterns on the pipe wall. In full-cone spray nozzles, wear typically results in a distribution pattern concentrated at the center of the pipe.

9.2.4 Spray nozzles should be flow tested to verify desired spray patterns, especially after a major process change.

9.2.5 The flow direction of the spray nozzles shall be verified during installation and subsequent maintenance reinsertions.

9.2.6 Anti-blowout features of retractable injection hardware (e.g., packing) should be periodically inspected for damage.

9.2.7 Thermography may be used to verify flow distribution where there is a temperature difference between the injectant and the process stream.

9.3 Inspection of Static Mixers

9.3.1 Static mixers should be inspected for damage to internal vanes and/or fouling.

9.3.2 In systems where configuration allows, radiography may be used to evaluate the condition, but this inspection should not be considered an alternative to visual inspection when the static mixer is taken out of the process piping.

9.3.3 Static mixers should be periodically inspected for functional deterioration. Comparing normalized pressure drop (calibrated for flow across the static mixer) to the design pressure drop should be considered for corrosive services.

9.4 Inspection of Thermal Sleeves

9.4.1 Thermal sleeves shall be regularly visually inspected to confirm mechanical integrity of the sleeve. This may require some form of external inspection technique (e.g., RT), intrusive inspection technique (e.g., boroscope) or when possible by its design, actual removal.

9.4.2 Inspection for thermal fatigue should be performed on a periodic basis. This would require the use of an inspection technique that is sensitive to cracking.

References

1. API 939-C (latest revision), Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries" (Washington, DC: API).
2. API 941 (latest revision), "Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants" (Washington, DC: API).
3. NACE Standard MR0103 (latest revision), "Materials Resistant to Sulfide Stress Cracking in Corrosive Petroleum Refining Environments" (Houston, TX: NACE).
4. API 582 (latest revision), "Recommended Practice and Supplementary Welding guidelines for the Chemical, Oil, and Gas Industries" (Washington, DC: API).
5. ASME B31.3 (latest revision), "Process Piping Design" (New York, NY: ASME).
6. API 570 (latest revision), "Piping Inspection Code: In-service Inspection, Repair, and Alteration of Piping Systems" (Washington, DC: API).
7. NACE SP0403 (latest revision), "Avoiding Caustic Stress Corrosion Cracking of Carbon Steel Refinery Equipment and Piping" (Houston, TX: NACE).
8. API 932-B (latest revision), "Design, Materials, Fabrication, Operation, and Inspection Guidelines for Corrosion Control in Hydroprocessing Reactor Effluent Air Cooler (REAC) Systems" (Washington, DC: API).
9. D. Baker, "Simultaneous Flow of Oil and Gas," *Oil Gas J.* 53, 11 (1954): pp. 183-195.
10. G.F. Hewitt, D.N. Roberts, "Studies of Two-Phase Flow Patterns by Simultaneous X-Ray and Flash Photography," United Kingdom Atomic Energy Authority (UKAEA),⁽⁴⁾ Atomic Energy Research Establishment (AERE) Technical Report, AERE-M2159 (Oxfordshire, UK: UKAEA, 1969).

⁽⁴⁾United Kingdom Atomic Energy Authority (UKAEA), Culham Science Centre, Abingdon, Oxfordshire, OX14 3DB, UK.

Appendix A Variables Affecting Mixing/Dispersion (Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

A1 Mixing

A1.1 Mixing is the uniform dispersion of an injected substance into a receiving stream, and is dependent on the turbulence of the mixed stream and the configuration of the injection apparatus.

A1.2 Mixing is relatively easy if the two streams are miscible, as they tend to dissolve into each other forming a single phase (e.g., injecting concentrated sulfuric acid into water producing a diluted acid stream). If they are immiscible (e.g., hydrocarbon and water), they remain separated, and mixing is the result of dispersion of particles.

A1.3 Sometimes mixing is promoted to cause a chemical or physical reaction (e.g., injection of gas oil and steam into the recirculating catalyst stream in a catalytic cracker). Knowing that dispersion and dissolution are time-dependent processes, complete mixing may not occur until the combined stream has moved 100 pipe diameters or more downstream.

A1.4 Flow eddies have a tendency to disperse injectant streams into the receiving stream. Increasing injectant stream velocity facilitates rapid mixing. In practice, this has been accomplished by use of a quill, sparger, or spray nozzle. The quill should be oriented for co-current injection.

A1.5 The rate of mixing depends on the flow regime at and downstream from the injection point. Flow regime depends on the mass flow (velocity) of the receiving stream, the number of phases present, and the relative density of the injectant and process streams. Increasing the velocity of the injectant stream facilitates rapid mixing. The rate of exchange of mass and energy (mixing) between phases in a multiphase system is a function of flow geometry and interfacial area, and is therefore dependent on flow pattern. Pipe size and process line orientation (horizontal or vertical) have an effect on mixing. The approximate flow regime of multiphase streams can be validated by use of empirical expressions.

A1.6 Figures A1 and A2 illustrate the two-phase gas-liquid flow regimes that can exist in horizontal and vertical up-flow piping configurations, respectively. The flow regimes in horizontal and vertical runs are different at the same parameters because of the effect of gravity.

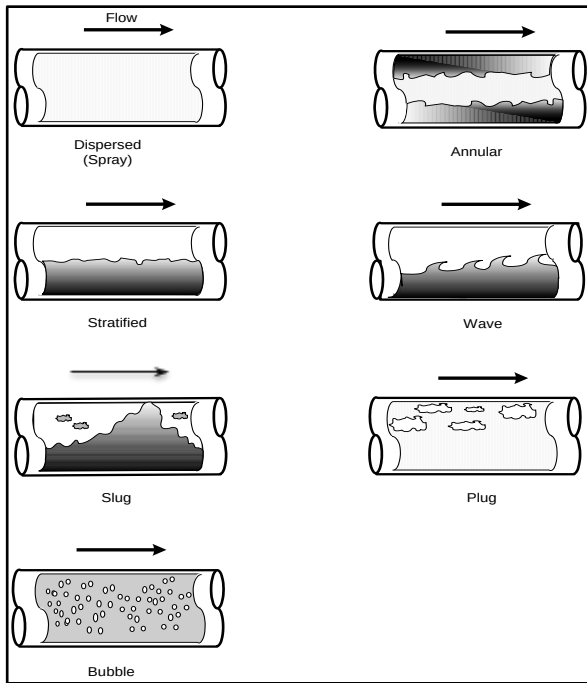


Figure A1: Flow Regimes in Horizontal Piping

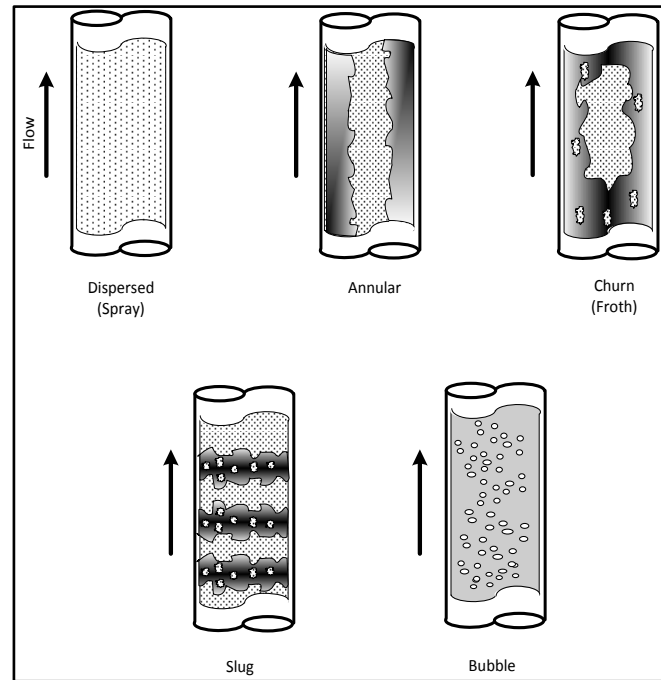


Figure A2: Vertical Up-Flow Regimes

A2 Flow Regimes

A2.1 In multiphase flowing systems within horizontal pipe runs, dense phases tend to settle to the bottom of the line, causing stratification, inhibiting mixing, and may prevent injectants from coming into contact with the intended stream.

A2.2 In bubble flow, the liquid phase is continuous and the gas phase is distributed as small bubbles, mostly toward the top of the pipe.

A2.3 In plug flow, gas bubbles are large, and their sizes can approach that of the pipe, although elongated in the direction of the flow.

A2.4 In stratified flow, gas and liquid phases are separated: the liquid phase on the bottom of the pipe, and gas phases on top.

A2.5 Wavy flow is defined as an extension of stratified flow where shear forces, as a result of the gas velocity, produce waves in the stratified liquid phase.

A2.6 Slug flow is an extension of wavy flow where shear forces, as a result of gas velocity, produce wave crests to reach the top of the pipe, resulting in alternating zones of completely gas and completely liquid phases.

A2.7 Annular flow is defined by the presence of a liquid film on the entire surface of the pipe, with gas phase in the annulus. The width of the liquid phase is typically thicker at the bottom of the pipe than elsewhere.

A2.8 Dispersed flow is the opposite of bubble flow, with a continuous gas phase and dispersion (mist/aerosol) of liquid droplets.

A2.9 In a worst-case scenario, slug flow can occur, increasing the potential of downstream piping or equipment damage as a result of momentum transfer.

A2.10 Figure A3 shows the Baker chart for gas-liquid flow regimes (nonflashing) in horizontal piping. The Baker plot use requires an understanding that the pressure drop is small, supporting the basis of a single vapor density and flow regime for the entire line.⁹

A2.11 Churn flow (not advisable) is not common in horizontal pipe runs, but can be in vertical up-flow runs. Churn flow is an intermediate regime between slug flow and annular flow. Its pattern is unstable, with the liquid traveling up and down the pipe in an oscillatory mode, but with a net upward flow. Instability results from competition between gravity and the liquid inertia.

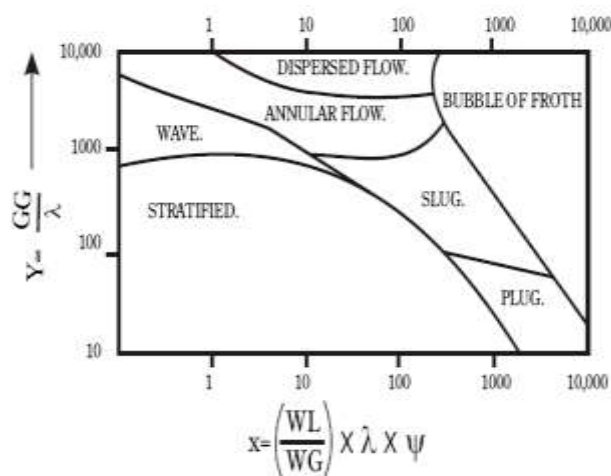
A2.12 Another flow pattern specific to vertical up-flow systems is wispy annular flow, which is characterized by entrained droplets in transient clouds or wisps of liquid in a vapor core.

A2.13 In gas-liquid flow with a continuous liquid phase, froth or churn flow regimes are conducive to rapid mixing. In gas-liquid streams with continuous gas phase, dispersed/aerosol/mist flow regimes that maximize interfacial area should be used.

A2.14 It is important to maintain a constant pipe run orientation in the mixing zone. It has been shown that inclination changes of 0.5° can affect flow patterns. Upward inclinations enhance slug flow, while downward inclinations enhance stratified flow.

A2.15 A two-phase (gas-liquid) flow pattern map for vertical up-flow was developed by Hewitt and Roberts¹⁰ (Figure A4). Note that the effects of gravity are not present, and no wavy flow exists.

A2.16 Changes in pipe system orientation can affect the flow regime, and thus affect the corrosion behavior. This is depicted in Figure A5. If such deviations to normal fluid flow exist, special attention must be paid to corrosion considerations when chemical injections rely on flow regime.



WL = liquid mass flow rate, lb/h
 Gg = Wg/A, lb/ft²-h
 Wg = gas mass flow rate, lb/h
 A = internal cross sectional area of pipe (ft²)
 WL = liquid mass flow rate, lb/h
 pg = gas density, lb/ft³
 ρL = liquid density, lb/ft³
 δ = surface tension, dyne/cm
 $\psi = [1.147/\delta][\mu L / \rho L]^{1/3}$
 $\lambda = 0.463(pg \cdot \rho L)^{0.5}$

Figure A3: Baker Plot Prediction of Flow Regimes for Horizontal Two-Phase Flow⁹

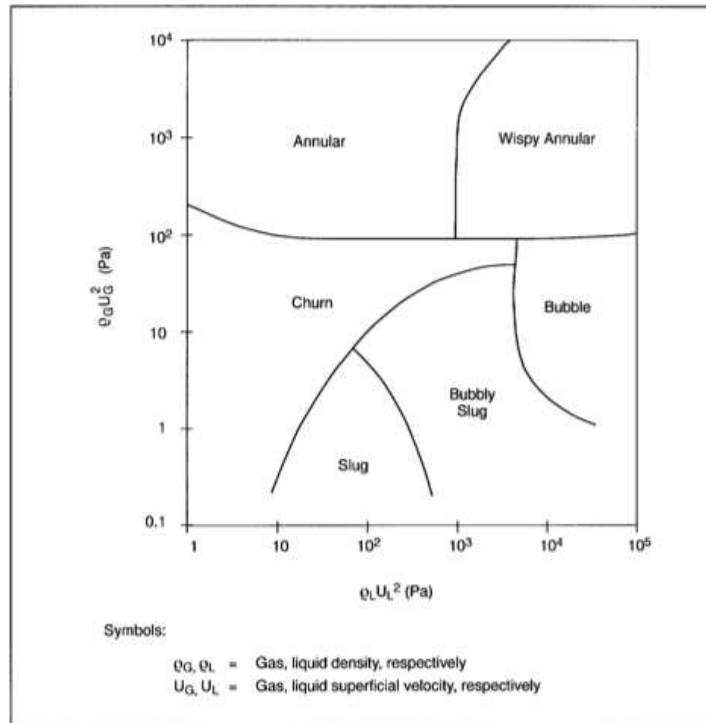


Figure A4: Hewitt and Roberts Two-Phase Up-Flow in Gas-Liquid Flow Streams in Vertical Piping.¹⁰ Regime Map

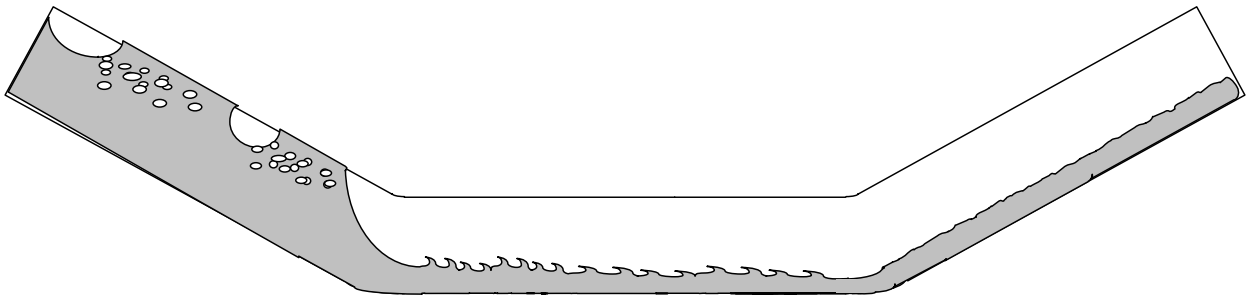


Figure A5: Change in Flow Regime as a Function of Inclination

Appendix B Case Histories (Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

Appendix B contains case histories, each a representative example of the common problems with refinery injection and mix points.

B1 Hydrodesulfurizing Unit Separator Overhead

B1.1 Water is usually injected into this hydrogen and light hydrocarbon stream to control ammonium salt fouling and corrosion. In nine cases reported, water injection into this type of processing stream led to localized corrosion problems. One case history discussed below provides a good example of both process and water-type injection point problems that are typical of the problems reported with this type of injection point.

B1.2 Figure B1 is a piping isometric of the water injection point into a naphtha hydrotreating unit hot separator overhead stream ahead of the effluent coolers. This dry hot naphtha and hydrogen stream contained ammonia, H_2S , and chlorides. Boiler feed water was injected as wash water.

B1.3 Injection was through a small connection into the main 250 mm (6.0 in) carbon steel piping. Two near-failures were reported in this facility (see detail in Figure B1). Initially, the outer radius of the elbow downstream from both the water wash and hydrogen recycle injection points suffered accelerated corrosion. An initial revamp of the piping was made, moving the hydrogen recycle injection to a point upstream from the water injection. This was partially successful. It was later found that the downstream tee that splits the flow before entering an air fin was suffering corrosion of 0.38 mm/y (15 mpy) in a localized zone just 75 mm (3.0 in) on one side of the tee. Flow rates were balanced, and subsequent corrosion rates were considered moderate. Corrosion is being managed by inspection at 12-month intervals vs. the balance of the line, which is inspected at 36-month intervals.

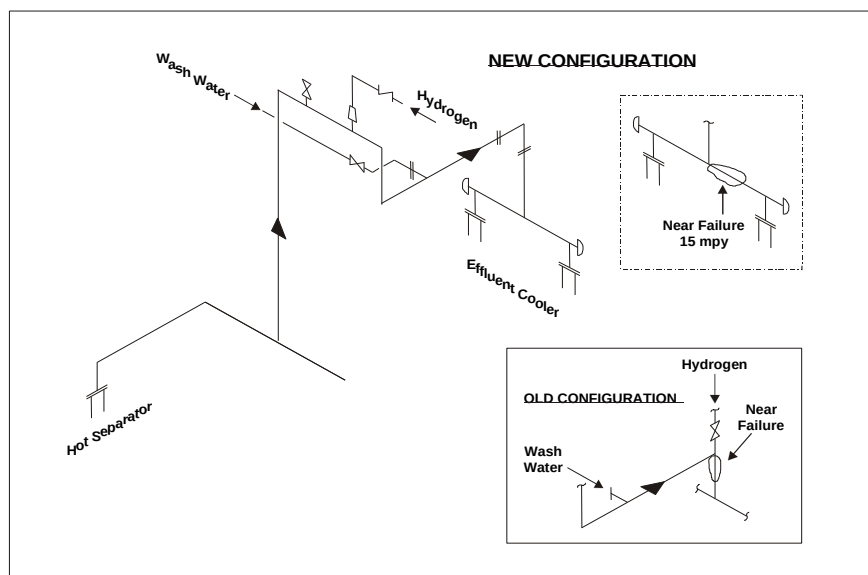


Figure B1: Hydrodesulfurizing Unit Separator Overhead Piping Isometric

B2 Atmospheric Crude Column Overhead Chemical Injection

B2.1 It is quite common to inject neutralizing and filming amine chemicals into this service to help combat corrosion associated with overhead acids, particularly in the downstream cooling and condensing exchangers. The case history discussed below reported localized corrosion that was typical of problems reported in 11 cases.

B2.2 Figure B2 is a piping isometric that summarizes the combined filming and neutralizing amine injection point into the atmospheric crude column overhead. Neat chemical was injected directly through a 19 mm (0.75 in) small carbon steel pipe connection into the carbon steel 500 mm (20 in) nominal pipe size (NPS) main line. A 0.0026 m² (4.0 in²) localized corrosion area, corroding at 0.63 mm/y (25 mpy), was reported on the main line 50 mm (2.0 in) downstream on the same side as the injection. Additional corrosion was reported on the downstream elbow located just 150 mm (6.0 in) away from the injection point. Corrosion was attributed to the neat chemical impinging on the carbon steel. Increased inspections and an upgrade were reported as being used to manage this problem. The injection device was changed to a straight quill type. After five years, no additional localized corrosion has been reported.

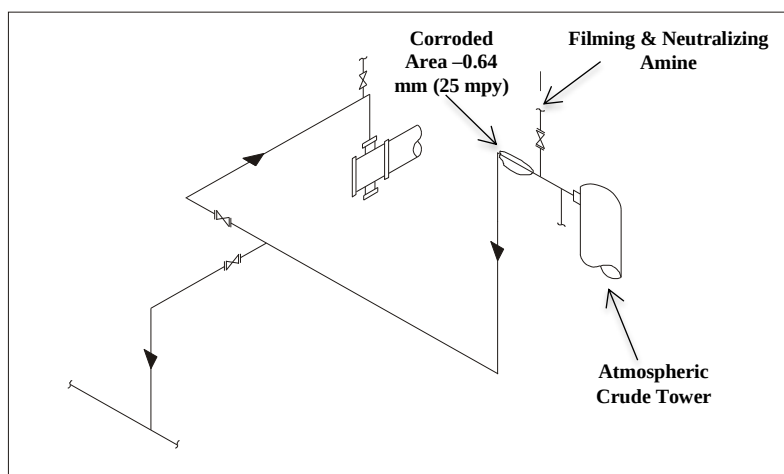


Figure B2: Atmospheric Crude Column Overhead Piping Isometric

B3 Light Ends Recovery Process Mix Point

B3.1 It is not uncommon to combine various sources of light hydrocarbons to be subsequently processed together in a refinery. Depending on the process source, each stream can contain different potential corrodents. By itself, each stream's corrodents may not cause corrosion, but when combined at the injection point, localized corrosion can occur. A common problem reported was the mixing of a catalytic reformer hydrogen or hydrocarbon stream containing chlorides with a water-containing stream from another plant. The combination leads to localized corrosion. Seven such cases have been reported in the initial NACE survey. The case history reported below is typical of such cases.

B3.2 Figure B3 is a piping isometric showing a location where liquid petroleum gas (LPG) from a catalytic reformer was injected into a fluid catalytic cracking unit (FCCU) light ends recovery unit. The 38 mm (1.5 in) NPS and 50 mm (2.0 in) NPS piping was of carbon steel construction. Localized corrosion at 1.5 mm/y (60 mpy) in a 0.0026 m² (4.0 in²) area downstream from the catalytic reformer LPG injection point was reported. (1 mpy = 0.0254 mm/y). Corrosion was also reported up to 60 m (200 ft) from the injection point, as well as in a downstream surge drum. Corrosion was attributed to the dry chlorides associated with the catalytic reforming stream combining with the water in the wet FCCU stream to cause HCl corrosion.

B3.3 Inspection at 12-month intervals (vs. 24 months on the remainder of the piping) was reported as helpful in managing this problem. Upgrades are being planned to move the catalytic reformer stream to upstream from a caustic wash tower and to upgrade the injection point material of construction to UNS⁽⁵⁾ N04400.

⁽⁵⁾ Unified Numbering System for Metals and Alloys (UNS). UNS numbers are listed in *Metal & Alloys in the Unified Numbering System*, 10th ed. (Warrendale, PA: SAE International and West Conshohocken, PA: ASTM International, 2004).

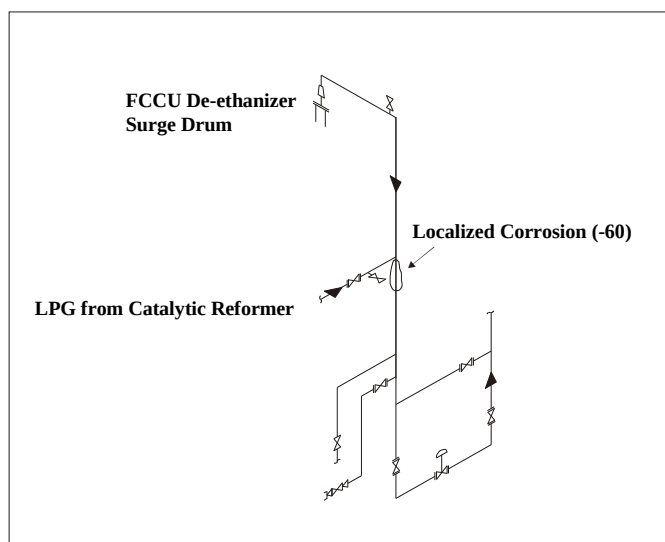


Figure B3: Light Ends Recovery Piping Isometric

B4 Mix Point Failure in H₂ Steam Methane Reforming Heat Recovery Train

B4.1 In refinery hydrogen manufacturing units, where the feed gas streams have been refinery off-gas streams, cracking of UNS S30403 has occurred at the bypass tees around syngas/deaerator feed heat exchangers (Figure B4). Cracking occurred where the mixing of two streams, two-phase, and at different temperatures, and was the result of corrosion fatigue. Cracking morphology was similar to what has been associated with chloride-induced SSC, but replicated in laboratory testing under conditions of measured corrosion potential and cyclic strain. A remedy to this problem included reorienting the tees, such that the two streams do not meet head to head in the run of the tee, reducing cyclic thermal strains. Additionally, fabricating the tees from higher alloys (e.g., UNS S31803/S32205 or UNS N06625) was recommended to eliminate the contributing corrosion element.

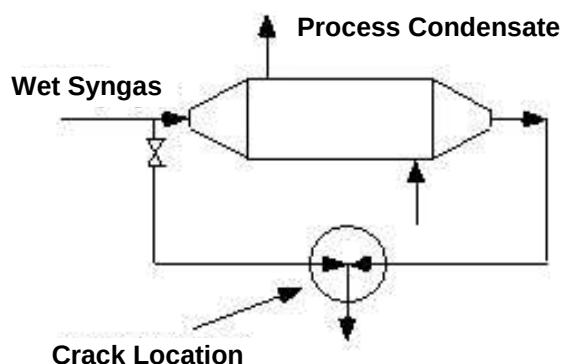


Figure B4: Location of Crack in Process Mix Point at Heat Exchanger Bypass

B.5 Saturate Gas Plant (SGP) Overhead Water Injection Point Failure

This case study describes a failure in a 150 mm (6 in) pipe in a saturate gas plant (SGP) unit that processes light hydrocarbons from refinery catalytic reformer and desulfurization units. The combined SGP feed streams contained high levels of ammonia, chloride, and hydrogen sulfide (H₂S) contaminants. The de-ethanizer overhead line (see Figures 5a, 5b, and 5c) failed near an intermittent water wash location.

The original unit design included facilities to water wash the SGP feed streams to remove inorganic salts that can promote corrosion and contamination of the products. At some time later, an additional water wash was added to the de-ethanizer

overheads system to flush out soluble deposits (hydrates) causing blockage in the overhead system. The injector was installed at an existing vent, and was not designed to industry practice, as it had no injection quill to disperse the flow, and was located close to a 90° elbow.

While exact operational history of the de-ethanizer overhead water wash could not be confirmed, operators indicated that the de-ethanizer overhead water wash was used on an intermittent basis to clear salts. It is understood that the original water wash was also used in a continuous mode for periods of time.

Inspection history showed that the de-ethanizer tower, overhead exchangers, and reflux drum were inspected regularly for corrosion. A risk-based inspection analysis of the piping was completed and inspection plans to inspect piping in the failed area were developed. Unfortunately, the pipe failed before implementation of these plans. It should be noted that the point of failure had not been identified as an active continuous/intermittent injection point.

In most refinery gas-processing units there is sufficient ammonia in overhead streams to neutralize H_2S . As a result of alkaline conditions, corrosion is not an issue unless the resultant ammonium bisulfide (NH_4HS) concentration, fluid velocity, and turbulence are high. This SGP location is probably unique in the refining industry because ammonia is virtually eliminated by the efficient feed water wash injection; however, very little H_2S was removed. Consequently, corrosion in the de-ethanizer overhead carbon steel piping was caused by acidic sour water.

In summary, the investigation revealed that failure was attributable to:

- Internal corrosion associated with a water wash injection location;
- The damage mechanism was acidic sour water corrosion as a result of the significant concentration of H_2S ;
- The injector location wasn't included in the refinery injection point management system and its operation was unknown; and
- The de-ethanizer overhead water injection location was not designed to industry standards.

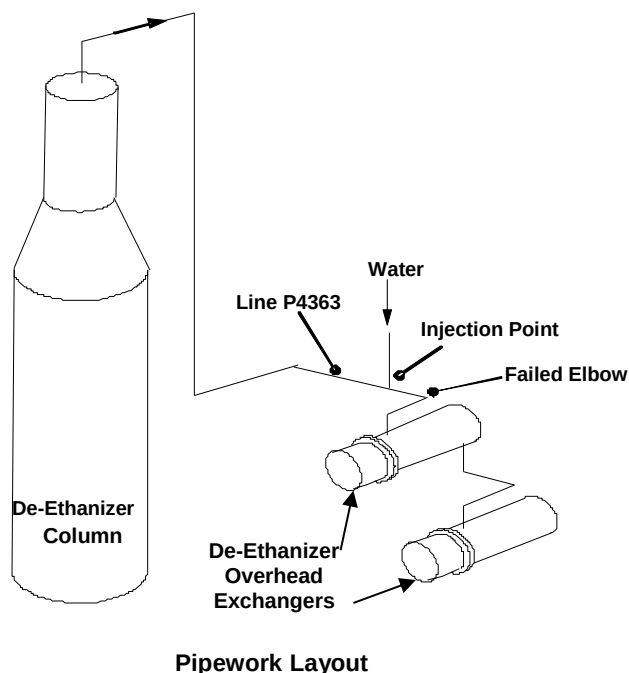


Figure B5a: Isometric of De-Ethanizer Line at Pipe Failure Location



Figure B5b: Failure Downstream from Intermittent Injection Point



Figure B5c: Failure at Extrados from Downstream Elbow

Appendix C
Sample Injection Point Data Sheet
(Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

INJECTION POINT DATA SHEET				NUMBER
PROJECT:		UNIT:		SHEET 1 OF 2
DEPARTMENT:		PRIORITY:		DATE:
NAME:	TELEPHONE:	EMAIL:		
CONTACT IF OTHER THAN ABOVE:				
PURPOSE OF INJECTION SYSTEM:				
1. RECEIVING STREAM DESCRIPTION				
NAME:				
STREAM CHARACTERISTICS: _____ CHEMICAL COMPOSITION (SPECIFY COMPONENTS & AMOUNTS)				
PHASE (G = GAS, L = LIQUID, S = SOLID)				
☐ G ☐ L ☐ G/L ☐ L/L ☐ G/S ☐ L/S OTHER _____				
IF MULTIPHASE, ESTIMATE PHASE VOLUME FRACTIONS _____				
IF SOLIDS PRESENT, ESTIMATE SIZE RANGE & COMPOSITION _____				
OPERATING TEMPERATURE: _____ °C (°F)		OPERATING PRESSURE: _____ MPA (PSIG)		
LINE SPECIFICATION: (SIZE, MATERIAL, ETC.)				
FLOW RATES (LB/HR)	NORMAL:	MIN:	MAX:	OPTIMUM:
BASIS FOR RATE ESTIMATES _____				
UPSTREAM EQUIPMENT _____		DOWNSTREAM EQUIPMENT _____		
IDENTIFICATION NO: E-XXX or PV-XXX, etc.		IDENTIFICATION NO: E-XX or PV-XX, etc.		
2. INJECTANT STREAM DESCRIPTION				
NAME:				
STREAM CHARACTERISTICS				
CHEMICAL COMPOSITION (SPECIFY COMPONENTS & AMOUNTS): _____				
PHASE (G = GAS, L = LIQUID, S = SOLID)				
☐ G ☐ L ☐ G/L ☐ L/L ☐ G/S ☐ L/S				
IF MULTIPHASE, ESTIMATE PHASE VOLUME FRACTIONS _____				
IF SOLIDS PRESENT, ESTIMATE SIZE RANGE & COMPOSITION _____				
OPERATING TEMPERATURE: _____ °C (°F)		OPERATING PRESSURE: _____ MPA (PSIG)		
INJECTION RATES (L/MIN [GPM])	NORMAL:	MIN:	MAX:	OPTIMUM:
BASIS FOR RATE ESTIMATES _____				
☐ CONTINUOUS INJECTION		☐ INTERMITTENT INJECTION		
DESCRIPTION OF INTERMITTANT INJECTION FREQUENCY				
LINE SPECIFICATION: (SIZE, MATERIAL, ETC.)				
UPSTREAM EQUIPMENT _____				
IDENTIFICATION NO: E-XX or PV-XX, etc.				
ATOMIZATION GAS (Y/N)? _____ NAME OF GAS: _____				
FLOW RATE (LB/HR): _____				
GAS TEMPERATURE AND PRESSURE UPSTREAM FROM INJECTION POINT		°C (°F)	MPA (PSIG)	
P & ID NO.	REV:	(ATTACH COPY IF AVAILABLE)		
NOTES				

	INJECTION POINT DATA SHEET TITLE	NUMBER
		SHEET 2 OF 2
3. INJECTION HARDWARE		
INJECTION POINT TYPE: NUMBER:	☐ INTERNAL QUILL ☐ INTERNAL SPRAY ☐ TEE CONNECTION ☐ SINGLE ☐ MULTIPLE	
INJECTION IS FROM OF VERTICAL PIPE	☐ TOP ☐ BOTTOM ☐ SIDE OF HORIZONTAL PIPE ☐ N ☐ E ☐ W ☐ S ☐ OTHER (DESCRIBE) _____	
DIRECTION OF INJECTION : ☐ COCURRENT ☐ COUNTERCURRENT ☐ CROSSCURRENT		
FLOW MEASUREMENT SYSTEM: _____		FLOW CONTROL SYSTEM: _____
IF VENDOR HARDWARE IS USED, DESCRIBE _____ ATTACH ANY AVAILABLE INFORMATION		
DISTANCE TO NEAREST DOWNSTREAM ☐ BEND, ☐ TEE, ☐ REDUCER, ☐ ORIFICE, ☐ THERMOWELL, ☐ OTHER INJECTION POINT, ☐ OTHER : DISTANCE _____ IF INJ. PT., DESCRIBE _____		
4. CHEMICAL AND PHYSICAL INTERACTIONS		
ANTICIPATED CHEMICAL REACTION (Y/N)? DESCRIBE: _____ ANTICIPATED PHYSICAL INTERACTION (PHASE CHANGE, EROSION, HEATING, ETC.) (Y/N)? DESCRIBE: _____		
5. STARTUP, SHUTDOWN, AND TURNDOWN OPERATION		
DESCRIBE STARTUP PROCEDURE: _____		
STARTUP FLOW RATE: _____		TURNDOWN FLOW RATE: _____
DESCRIBE INJECTION SYSTEM OPERATION WHEN FLOW RATE OF RECEIVING STREAM IS ABOVE OR BELOW DESIGN RATE: _____ _____		
DESCRIBE SHUTDOWN PROCEDURE: _____ _____		
DESCRIBE PROPOSED FREQUENCY, LOCATIONS, AND METHODS OF INJECTION POINT INSPECTION: _____ _____		
NOTES/SKETCH (ATTACH ADDITIONAL SHEETS IF REQUIRED)		

Appendix D Hardware Design Philosophy (Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

D1 Injectant Dilution Strategies

D1.1 When injecting an agent that requires dilution, two basic systems are used: (Figures D1 and D2).

(a) A charge tank with a manually operated valve on the incoming chemical or diluent stream, a mixer or air sparger, and a pump/piping delivery system. Often, chemicals are dumped into the tank, which is then filled with diluent, mixed, and finally metered into the process stream. Its main disadvantage is that it requires operator involvement during the batch addition and mixing step. The batch nature of the process increases the risk of improper dosage as a result of variability of blending.

(b) This more controlled method meters the injectant into a diluent slip-stream, straight from its shipping/storage container. Automatic control of both dosing and dilution ratios can be achieved by altering the pump settings in the diluent pump, the dosing pump, or both pumps. This second approach reduces dosing inconsistencies.

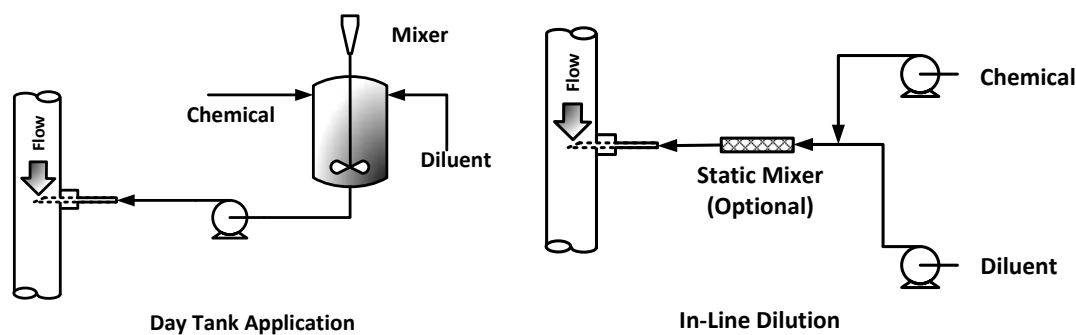


Figure D1: Chemical Dosing Alternatives

D2 Mixing Apparatus Components

D2.1 Retractable injection devices, normally sealed in a packing gland, can be advantageous in situations in which fouling of the injection device can occur during service (see Figure D2). The disadvantages of retractable injection devices are the potential for leaks because of packing problems and the potential for incorrect operation. Also, in hydrogen service, because of the small size of gas molecules, leakage at the packing gland can be anticipated.



Figure D2: Retractable Quill Assembly

D2.2 While injection through a spray nozzle is preferred to other methods and should be used when possible, quills are typically used primarily in very low-flow applications.

D2.3 Quills can be made of carbon steel for benign services, and alloys UNS S31603 to UNS N10276 for corrosive environments. Nonmetallic materials, typically polyvinylidene fluoride (PVDF), polyvinylchloride (PVC), and chlorinated polyvinyl chloride (CPVC), can be used, but chemical compatibility and code pressure ratings must be determined. If cast materials are specified, volumetric examination (e.g., radiographic examination) should be used.

D2.4 If UNS S30403/UNS S30408 (e.g., 300-series stainless steels) are being considered, use of the dual grades is beneficial as the low carbon concentration inhibits intergranular stress corrosion cracking (SCC), while maintaining the benefits of higher allowable strengths for nonelevated temperature service. Alternatively, the use of chemically stabilized grades of stainless steels (e.g., UNS S32100 or UNS S34700) offers the same advantages.

D2.5 The injection quill is a common component for metallurgical upgrade, mostly to austenitic stainless steels, and sometimes to Ni-Cr-Mo alloys. The materials of construction shall be compatible with the additive being injected (e.g., UNS N04400 and other copper-bearing alloys are not compatible with amines).

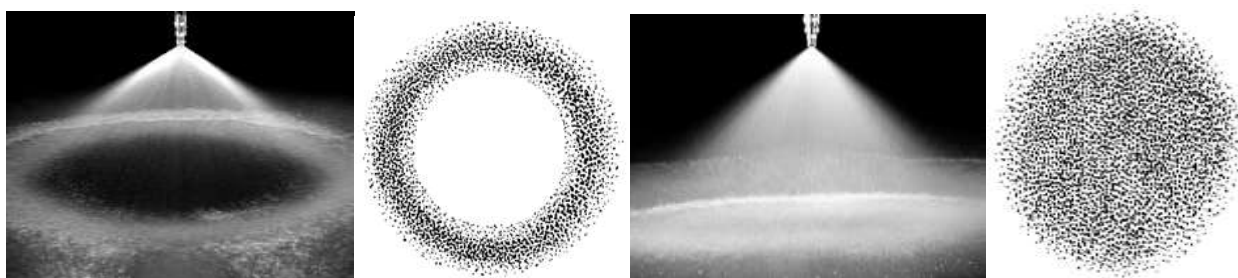


Figure D3: Hollow-Cone and Full-Cone Spray Distribution

D3 Spray Nozzles

D3.1 Factors that affect spray nozzle performance are spray pattern (Figure D3), droplet size, injection device pressure and process pressure (i.e., ΔP), and volume delivery.

D3.2 Droplet size is defined as the size of individual droplets in a spray pattern, each pattern exhibiting a range and distribution of droplet sizes. For some applications, creating small droplet size through the use of an atomizing nozzle using a coinjectant or diluent to further break up the injectant can be advantageous. The smallest droplets are produced by gas atomizing nozzles, and the largest droplets by full cone nozzles.

D3.3 Pressure drop effects droplet size. An increase in pressure drop reduces droplet size, while lowering pressure drop increases droplet size. Each spray nozzle has a minimum allowable pressure drop. Below that minimum pressure drop, the spray pattern collapses, adversely impacting performance. The user should consult with the nozzle manufacturer for determining the minimum allowable pressure drop.

D3.4 Injectant viscosity and surface tension increases the energy requirement for atomization. An increase in these properties increases the droplet size.

D3.5 Spray nozzles in multiple nozzle headers should be designed to have an orifice pressure drop large enough (typically 10:1 min. compared to header pressure drop) such that there is equal flow of injectant out of each nozzle, again promoting equal dispersion. When gas (e.g., steam) is used to enhance the dispersion of liquid injectants, the injection device should be sized to handle the increased throughput and pressure drop.

D3.6 Generally, the nozzle manufacturers' droplet size data is based on laboratory tests using water. Nozzle selection (droplet size) should account for the effect of the actual properties of the injectant, and any carrier/diluent, at the process conditions.

D3.7 Spray nozzles for wash water systems should produce full cone patterns with spray angles between 30 and 120°. Spray angle affects droplet size; increasing spray angles reduces average droplet sizes, and reducing spray angles increases droplet size.

D4 Static Mixers

D4.1 Static mixers are in-line flow devices that use the energy of the flow stream to create mixing between two or more fluids. Static mixers use a series of fixed elements, typically, but not always helical, enclosed within a cylindrical housing, typically a flanged pipe section. Static mixer designs produce patterns based on flow division and radial mixing, achieving high rates of mixing with the lowest possible pressure drop. Effective mixing of two streams in laminar flow requires the use of a static mixer. The number and geometry of the mixing elements are based on the viscosity of the fluids to be mixed and the Reynolds number of the process stream.

D4.2 In noncorrosive environments, the mixing elements in static mixers may be fabricated from carbon steel, stainless steel, or polymeric materials. In corrosive environments, stainless steel, Ni-Cr-Mo alloys, or polymeric materials should be used.

D5 Spargers

D5.1 Spargers (Figure D4) can be used to distribute the injectant stream at the point of injection over a wide cross section of the receiving stream. This promotes more rapid mixing than can be achieved using a single mix point.

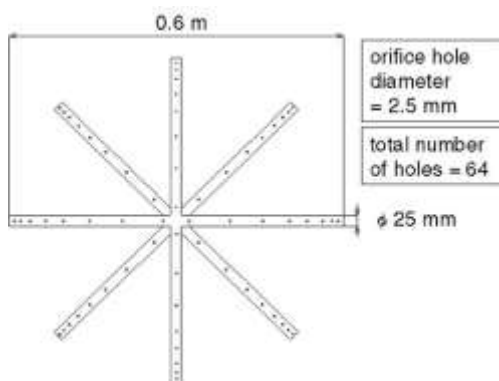


Figure D4: Radial Sparger

D5.2 A rule of thumb associated with sparger design is that the small sparger delivery holes should be designed with a pressure drop that is at least 10 times the pressure drop across the length of the sparger to assure an even distribution of injectant.

D6 Pumps

D6.1 Injection pumps are usually, but not always, the metering type. Flow rates can be controlled automatically by pneumatic actuators or electric motors that change the pump stroke length, or by variable speed drives. Turndown to 10% of the maximum flow rate is achievable.

D6.2 Pump outlet pressure has to be set to overcome the maximum operating pressure of the receiving process or coinjectant stream, and all of the injection system pressure losses (hydrostatic, friction, etc.), but lower than the maximum design pressure of the refinery process loop.

D6.3 Pumps are typically equipped with an internal bypass or an external kick-back loop to prevent system over-pressurization and/or pump damage.

D6.4 Metering pumps, depending on the size, should be equipped with in-line pulsation dampeners. Acceleration of fluid in pump discharge lines may affect the pump's maximum pressure capacity or cause the relief valve to momentarily lift. Pulsation dampeners can minimize acceleration-induced pressure pulses, reducing harmonic resonances in the piping circuit.

D6.5 Process fluid wetted pump parts should be made from materials that are compatible with the injectant. The diaphragms are typically made of polytetrafluoroethylene (PTFE)-coated steel, stainless steel, or higher alloys. The check valves and seats are made of similar compatible materials, including austenitic stainless steel and ceramics.

D7 Flow Meters

D7.1 Flow meters are necessary elements in the sustainability of quantifiable injection rates. Types of flow meters include rotameters, differential pressure flow meters (e.g., orifice, venturi), turbine meters, and mass flow meters.

D7.2 Each of these flow meters has advantages and disadvantages. For example, rotameters and differential pressure flow meters are the least expensive, and although they have been known to plug, offer acceptable flow measurement for most fluids and gases.

Appendix E Considerations for Typical Refinery System Injection Designs (Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

E1 Caustic Injection

E1.1 Caustic

E1.1.1 Caustic should be added in a dilute form typically as a 3 to 5 wt% aqueous solution. Only fresh, low-chloride caustic (NaOH) should be used.

E1.1.2 Spent caustic should not be used since it has variable amounts of “free” or available NaOH to neutralize the HCl formed. Spent caustic usually contains unknown reaction products that can contribute to overhead corrosion.

E1.1.3 Caustic concentration should be controlled to limit the risk of caustic embrittlement and to minimize impact to downstream equipment, associated piping, and processes, such as DCU heater fouling, coke quality, and FCCU and catalyst deactivation because of sodium (Na) in downstream reduced crude.

E1.2 Injection Location Considerations

E1.2.1 Caustic solutions should be injected immediately after the desalter or crude preheat flash vessel, preferably via a quill into the suction of the desalted or flashed crude pump. An alternative location is in a straight section of the piping, immediately downstream from the desalted crude pump, through an injection quill to disperse the solution and keep it away from the pipe wall. Typically, desalted crude temperatures can be expected to exceed 150 °C (300 °F), promoting the possibility of caustic embrittlement and caustic gouging (corrosion) at elbows and tees unless proper precautions are taken. A robust system to minimize the potential for caustic damage includes taking a small slipstream off the main crude line, injecting the caustic solution, and pumping the stream through a mechanical mixer (static in-line mixer) before returning it to the hot crude line.

E1.3 Design Considerations

E1.3.1 Materials of construction for any components of the system that can be exposed to caustic solutions at temperatures above 50 °C (122 °F), or those that are heat traced, shall be either stress-relieved carbon steel or an alloy resistant to caustic embrittlement (e.g., UNS N10276). Electric heat tracing can be controlled to a low enough temperature that stress relieving may not be required. This is more difficult with steam tracing.

E1.3.2 Freeze protection may be required depending on the strength of the caustic and the refinery location. The type of heat tracing used should be evaluated during selection of materials to ensure that the two are consistent.

E1.3.3 Positive shut-off of caustic lines should be considered to prevent damage during abnormal operations.

E2 Crude Overhead Injections—Neutralizer Injection

E2.1 Location

E2.1.1 Single-Stage Systems

E2.1.1.1 Neutralizer shouldn't be coinjected with the filming inhibitor because of possible chemical reactions between these chemicals and because injection point design criteria are different for neutralizers and filmers.

E2.1.1.2 Neutralizer injection location should be upstream from the location where the gas stream reaches the water dew point. In the case where water wash is used to force the water dew point the neutralizer should be injected with the water wash; however, when maldistribution of water wash is expected, injection via this method may impact distribution of the neutralizer in overhead circuits. The neutralizer location varies with system design and operation. Single-stage atmospheric tower overhead systems (without water wash) are typically treated by neutralizer additions into the vapor line leaving the top of the column, generally well upstream from elbows and tees, to reduce the potential for impingement and erosion-corrosion.

E2.1.1.3 When estimating water dew points, it is important to include all sources of water, but primarily stripping steam from the atmospheric column and side strippers. For units that do not have a preflash tower with overhead condensers and water draw, water from desalter carryover and caustic injection should also be considered. It is important to evaluate the water dew point over the full range of unit operating conditions (i.e., the full range of overhead water rates and hydrocarbon rates) and to consider the potential for shock condensation on cold tube walls and the colligative effects of impurities on the dew point.

E2.1.2 Multiple-Stage Systems

E2.1.2.1 For overhead systems with two or more condensing stages, a careful evaluation of the first-stage overhead system should be performed to determine whether the aqueous dew point occurs. The same factors should be considered for estimating water dew point in multistage systems as for single-stage condensing systems.

E2.1.2.2 No neutralizer should be injected into a dry condensing stage to avoid buildup of neutralizer salt deposits and resultant under-deposit corrosion.

E2.1.3 Equipment

E2.1.3.1 The neutralizer should be injected using a quill or spray nozzle to get good distribution in the overhead vapor.

E2.1.3.2 Corrosion-resistant alloys should be used to ensure that neutralizer distribution does not deteriorate over time. A material such as UNS N10276 is typically used. Injection is typically into the center of the pipe in the direction of flow.

E2.1.3.3 A carrier/coinjectant stream (such as steam) can be used to improve dispersion and vaporization of the neutralizer into the overhead vapor stream.

E3 Crude Overhead Injections—Filming Corrosion Inhibitors

E3.1 Types of Filming Corrosion Inhibitors

E3.1.1 Filming inhibitors can be formulated for injection as oil-soluble, water-soluble, or water-dispersible additives.

E3.1.2 The type of filming inhibitor selected should be consistent with the type of carrier stream used, as well as the design of the overhead system.

E3.2 Location

E3.2.1 Filming inhibitor injection points are generally well upstream from pipe elbows/tees to reduce the potential for impingement and erosion/corrosion, and are typically injected upstream from the first point of water condensation (aqueous dew point). It is injected at one or more selected locations to ensure adequate distribution to all parallel banks of overhead condensers.

E3.2.2 In many cases, multiple filming inhibitor injection locations are used to achieve adequate distribution because of the size and complexity of the overhead system.

E3.3 Specific Design Considerations

E3.3.1 Carrier Streams

The filming inhibitor compounds have high molecular weights, and when deposited in bulk quantities, cause fouling and corrosion of metal surfaces. The carrier stream provides a liquid phase to foster the distribution of the filming inhibitor while avoiding bulk deposition. A carrier stream shall be used for filming inhibitors. Injection rates should be measured and controlled in accordance with supplier recommendations (typically in the range of 20:1 to 100:1 carrier-to-inhibitor ratios). Use of a warm diluent should be used to minimize the risk of shock condensation. The diluent should not flash significantly when injected into the overhead system to avoid concentrating the filmer and causing local cooling in the overhead stream.

E4 Crude Unit Overhead Water Wash

E4.1 Water Wash Considerations

E4.1.1 If the overhead vapor velocity is greater than 31 m/s (100 fps), water wash should not be used because of the increased risk of erosion-corrosion.

E4.1.2 If water wash is used in a high-velocity system, special design precautions may be required to minimize the erosion-corrosion risk.

E4.1.3 If the process stream velocity is too low, water wash distribution may be poor, especially in horizontal pipe or exchanger tubes.

E4.1.4 When water wash is employed, the quantity should provide at least 25% excess water, beyond what is required to bring the atmospheric tower overhead stream to the aqueous dew point at the injection point.

E4.1.5 Overhead vapor temperatures have a strong influence on the quantity of wash water required. As the overhead process stream temperature increases, the fraction of injected water that vaporizes also increases. Therefore, increased wash water requirements should be based on maximum operating temperature to ensure excess water targets are achieved under all operating conditions.

E4.1.6 Insufficient wash water quantity can lead to poor scrubbing efficiency and/or creation of corrosive water-wetted salts.

E4.1.7 Water recycled from the atmospheric tower overhead drum is a common source of wash water. Stripping steam and/or entrained water from the desalter provides a continuous source of fresh condensate to purge contaminants from the system. Boiler feed water, although costly, is high-quality wash water. Another possible water source is stripped sour water. The concentration of oxygen, NH_3 , H_2S , and other acids is low with a good sour water stripper operation.

E4.1.8 Fresh water such as well water, surface water, raw water, cooling water, and cooling tower blowdown should not be considered as water sources because they can be saturated with oxygen and scale-forming minerals. Other refinery process condensates containing significant levels of corrosives should not be used as a source of wash water. These sources include hydrotreater sour water, FCCU and coker waters (both of which can contain ammonium bisulfide and cyanides), and water from caustic treatment units.

E4.1.9 A properly designed continuous water wash is typically preferred over an intermittent water wash. A well-designed continuous water wash system should always experience less corrosion than intermittent wash water systems. There may be times, however, when constraints, such as accumulator boot water handling capacity or pumping capacity, prevent using continuous water washes.

E4.1.10 Contrary to other systems, in crude tower overhead systems intermittent water washes should be minimized because intermittent washing promotes continuously wetted salts, and increases the risk of under-deposit corrosion. Intermittent water washing requires operator attention to assure complete salt removal, and to initiate subsequent washes at the appropriate time. If intermittent water wash is used, a self-draining design and positive isolation, either double-block and bleed, or blinds, shall be used to ensure the water does not leak into the process when not in use.

E4.1.11 There also are options that combine continuous and intermittent water wash that can be considered. One option continuously injects wash water into the main overhead line, and then intermittently washes at the inlet of each bay of the air cooler. Some units with wash water limits have automated cycles to continuously wash individual banks of exchangers one at a time to ensure that each part of the system is routinely washed.

E4.2 Location

E4.2.1 Water wash injection locations are generally selected to either maximize vapor/water contact time and scrubbing efficiency or to get the best possible distribution. If contact time and scrubbing efficiency is the goal, then wash water should be injected into the center of the pipe via a spray nozzle in the downstream direction so that the spray pattern is maintained as long as possible.

E4.2.2 Wash water should be injected into the vertical run of the overhead line at least 10 pipe diameters upstream from the first-stage overhead (reflux) condensers and from any changes in flow direction such as elbows or tees.

E4.2.3 With respect to overhead condensing systems with multiple banks of air-cooled or shell and tube exchangers, poor distribution of wash water in unbalanced piping configurations is a major source of corrosion failures. For best distribution, wash water should be injected at the inlet to each bank of exchangers or each air cooler bay.

E4.2.4 For a double drum overhead configuration that operates dry, water wash is normally injected upstream from the second-stage condensers. When the first-stage overhead drum operates wet, water can be injected into the atmospheric tower overhead line upstream from the first-stage overhead (reflux) condensers, at the inlet to each bank of exchangers or each air cooler bay, as well as upstream from the second-stage condensers.

E4.2.5 All of the considerations discussed previously would apply to both injection locations in this situation.

E4.2.6 In some cases, low velocity and poor distribution may be resolved by the installation of wash water injection nozzles in the condenser shell. These wash nozzles can be used intermittently or continuously.

E4.3 Specific Design Considerations

E4.3.1 All system components, especially the pump, spray nozzles, and accumulator boot should be designed for the full required capacity. Improper design can lead to inadequate capacity and/or poor performance.

E4.3.2 The injection nozzle should be sized for sufficient pressure drop to minimize droplet size and to provide some turndown without collapsing the spray cone, typically around 20 psi (140 kPa).

SP0114-2014

E4.3.3 To minimize plugging, the nozzle should have a single bore, maximizing the free passage for a given pressure drop. In addition, filters or strainers may be used to trap solids and prevent plugging.

E4.3.4 Injection quills or spray nozzles are generally provided and constructed with a corrosion-resistant material such as UNS N10276 (Alloy C-276). For heavy-walled, low-stress nozzles leaner alloys such as UNS S31603 may be used. Carbon steel is normally sufficient for other components in the system.

E5 Desalter Water Wash

E5.1 Wash water can be injected upstream from the raw crude preheat train or just upstream from the mix valve in front of the desalter.

E5.2 Wash Water

E5.2.1 Water usage rate should be adequate for the gravity of crude being processed, typically 3 to 5 vol% of the crude charge rate for light crudes and 6 to 12% for heavy crudes. Ideally, wash water should be neutral pH or slightly acidic, and low in ammonia, chlorides, oxygen, tramp amines, hardness, and solids.

E5.3 Location

E5.3.1 The most common location for a water wash on single-stage desalters is just upstream from the mix valve. The mix valve serves to bring oil and water into intimate contact, promoting mass transfer of chlorides into the bulk water phase.

E5.3.2 For crudes with significant amounts of crystalline salts, or with very little free water, consideration should be given to injecting all or part of the wash water at the front end of the crude preheat train. The purpose is to maximize contact time for removing crystalline salts and to prevent crystalline salt formation that results when all the free water in "dry" crude dissolves into the oil as the crude is heated.

E5.3.3 For two-stage desalters, fresh make-up water should be injected upstream from the mix valve in front of the second stage. The water from the second stage is then cascaded back to the first stage, either upstream from the mix valve or at the front end of the unit as discussed previously.

E5.4 Specific Design Considerations

E5.4.1 No special measures are normally taken when injecting desalter wash water into crude oil.

E5.4.2 Injection quills or spray nozzles are not typically used to enhance oil/water mixing. Instead the mix valve or turbulence in the crude preheat train are relied on to carry out that function. There are special low-shear mixing devices sometimes used to enhance mass transfer without making it difficult to break emulsions. These devices can be static mixers or other proprietary devices.

E6 Wash Water in Hydrocracker/Hydrodesulfurizer Reactor Effluent Streams

E6.1 Wash Water Considerations

E6.1.1 Quality

The preferred source from a quality standpoint is steam condensate, or deaerated boiler feed water before boiler water treatment chemicals are added. Another acceptable source is stripped sour water (only from a sour water stripper dedicated to hydroprocessing units). This reduces the demand for boiler feed water/condensate makeup. Table E1 provides wash water quality guidelines.

Table E1
Guidelines for Wash Water Quality

Property	Maximum Recommended	Suggested Targets
Oxygen (ppbw)	50	15
pH	9.5	7.0 – 9.0
Total Hardness (ppmw as Ca hardness)	2	< 1
Dissolved Iron (ppmw)	1	0.1
Chlorides (ppmw)	100	5
H ₂ S (ppmw)	< 1,000	
NH ₃ (ppmw)	< 1,000	
Free Cyanide (ppmw)	–	0
Total Suspended Solids (ppmw)	0.2	Nil

E6.1.2 Amount:

E6.1.2.1 The hydrocracker/hydrodesulfurizer wash water injection rate shall be controlled to meet the more restrictive of either the maximum allowable ammonium bisulfide concentration or the minimum % free water at the injection point. The maximum allowable ammonium bisulfide should be 2 wt% in the separator water for carbon steel reactor effluent systems or 10% for alloy systems. An alternative to these fixed limits is to use more detailed corrosion modeling based on actual unit design and operating conditions to set limits based on maximum allowable corrosion rates.

E6.1.2.2 The fraction of wash water that remains in the liquid phase after injection into the effluent is important for ensuring adequate “wetting” of the downstream equipment/tubes. Enough water should be injected to ensure that a minimum of 25% of the injected water remains as liquid at the inlet of the exchanger. Insufficient water in the aqueous phase leads to higher frequency of localized corrosion.

E6.1.3 Continuous vs. Intermittent

E6.1.3.1 Continuous water injection is preferred to control NH₄HS salt-deposition corrosion and fouling. Intermittent water injection should only be used for NH₄Cl salt-deposition corrosion and fouling control and where the NH₄HS concentrations are very low such that salt deposition is unlikely or very slow. It is not preferred, but intermittent water wash may also be used when insufficient water supply or handling capacity is available to meet continuous injection rate requirements.

E6.1.3.2 If intermittent water wash is used, positive isolation, either double block and bleed or blinds, shall be used to ensure that water does not leak into the process when not in use. Downstream sour water should be measured for a reduction in salts to determine the intermittent injection intervals.

E6.1.4 Location

E6.1.4.1 The continuous water wash injection location should be located upstream from where NH₄HS salt deposition occurs, typically in front of the effluent air or water cooler.

E6.1.4.2 The intermittent water wash location should be just upstream from the exchanger where NH₄Cl deposition is expected to occur, typically near the end of the reactor feed/effluent heat exchange train.

E6.1.4.3 Continuous metered injection through a single point into a balanced (symmetrical) piping system (inlet and outlet) should be used.

E6.1.4.4 When the inlet and outlet piping is not balanced and symmetrical, a separate water injection point for each air cooler nozzle or shell and tube inlet is preferred. Flow monitoring for each injection location is required. The injection piping should be manifolded so that each bay can be periodically slugged with a high rate of water to remove any accumulated salts or scale. This injection location should be upstream at least 10 pipe diameters from any change in direction in the piping system. The preferred location for the injection point is in the vertical run. If adequate distance is not available, the use of static mixers is an option. It is often beneficial (and most practical) to inject close to the header box to help ensure that droplets are carried into all the tubes.

E6.1.4.5 Water should be injected co-currently into the middle of the process stream through an injection device to ensure the water is thoroughly dispersed within the process stream.

E6.1.5 Specific Design Considerations

E6.1.5.1 Injection equipment (spray nozzle/static mixer) should be constructed of a corrosion-resistant alloy (e.g., UNS N10276 or UNS N06600). The recommended nozzle type is a narrow full-cone spray width, providing a wide enough angle to get good distribution across the pipe without directly impinging on the pipe wall. Carbon steel is normally adequate for piping and other injection system components.

E7 Polysulfide Injection in Fluidized Catalytic Cracking (FCC) and Delayed Coking Units (DCU) Systems

E7.1 CN^- limits the formation of a passivating layer of FeS reaction by complexing with ferrous ions in the aqueous solution (Equation E1). APS reacts with CN^- , converting it to innocuous SCN^- ion, which is a much weaker complexing agent).



E7.2 It is typical for the CN^- concentration in wash water to become slightly elevated after APS is injected as it helps to remove additional CN^- from the hydrocarbon stream. Prussian blue tests may be performed on the sour water to confirm the presence of ferrocyanide complexes. While this test confirms the presence of ferrocyanide, it does not provide a measurement of the blistering potential.

E7.3 Care should be taken to not inject the APS at too high a rate, as high APS concentrations may result in water/oil separation problems and precipitation of sulfur.

E7.4 The design should be made to first maximize the use of wash water to remove the contaminants and then to use APS to treat any remaining CN^- issues. Water wash is typically continuous but the APS injection rate may be intermittent or varied based on the unit feeds and operation. The APS may not always be needed.

E7.5 Water Wash Quality

E7.5.1 In water at pH as low as 7, APS is unstable and decomposes into NH_3 , H_2S , and elemental sulfur. The preferred source of wash water is alkaline sour water ($\text{pH} > 8$), as it promotes APS stability.

E7.5.2 The wash water should be free of oxygen and should not add contaminants to the system.

E7.6 Location

E7.6.1 The location of the APS injection point and water wash injection can vary. Injection points for wash water and APS shall be ahead of the first condensation point of water. This location varies with system design and operation and may require more than one APS injection location.

E7.6.2 The injection location shall be far enough upstream from the dew point location to ensure that adequate mixing and distribution occurs before the water separator. The injection location shall be at least 10 pipe diameters (20 pipe diameters is preferred) from any change in process flow direction or downstream equipment.

E7.6.3 The location shall also consider the temperature of the process stream, limiting the temperature to 110°C (230°F), thus preventing thermal decomposition of APS into NH_3 , H_2S , and elemental sulfur, the first two of which can promote corrosion of carbon steel.

E7.6.4 Wash water removes contaminants from the hydrocarbon, and the water is then removed from the unit via the water boot of the accumulator drums.

E7.6.5 Overhead water pH depends on system design and operation and may vary from below 6 to above 8.

E7.6.6 It is critical that all the water be separated from the hydrocarbon and removed at the drums before the hydrocarbon is heated. Without good separation, the resultant dry point in an exchanger may have a high corrosion rate as a result of the NH_3 being driven off first and the remaining water becoming very acidic.

E7.7 Equipment

E7.7.1 The APS and wash water should be injected co-currently into the middle of the process stream through a mixing quill to ensure the water is thoroughly dispersed within the process stream. A static mixer may be installed downstream from the quill to assist with mixing or if there is an inadequate distance downstream as detailed in Paragraph 5.25.

E7.7.2 Injection equipment (spray nozzle/static mixer) should be constructed of a corrosion-resistant alloy (such as UNS N08020 or UNS N08825, or even UNS S31603 in low-chloride environments), and visually inspected during each turnaround. The nozzle type that should be used is a narrow full-cone spray with a wide enough angle to get good distribution across the pipe without directly impinging on the pipe wall. Carbon steel is normally adequate for piping and injection system components.

E7.7.3 As with other chemical storage tanks, APS storage tank design should include a blanketing system to mitigate corrosion in the vapor region of the tank and to limit product contamination.

E7.7.4 Below 3 °C (38 °F), APS tends to precipitate out of concentrated solutions. Above 54 °C (130 °F), APS starts to break down. Electric heat tracing (not steam) and insulation should be used to maintain the temperature above 10 °C (50 °F) for APS storage and delivery systems to maintain APS solution stability. Vapor emissions from the storage tank, off-loading equipment, and leaks must be evaluated and controlled. Decomposition of APS results in H₂S and NH₃ vapor leakage. Vapor recovery has been required in some installations.

E7.8 Water Handling Capacity

E7.8.1 When designing or changing the operation of the water wash system, it is important to consider the capacity of all the key components in the system, especially the pump, spray nozzles, vessel internals, and accumulator boot.

E7.8.2 If the water wash rate decreases, the nozzle spray pattern could collapse, resulting in ineffective mixing. If the rate increases significantly, the increase in pressure drop may prevent achieving the desired rate.

E7.8.3 If the accumulator and its boot are inadequate for the amount of water that needs to be handled, water could be entrained in the hydrocarbon, resulting in carryover of water-soluble contaminants back to the process or to downstream units.

E8 Injection of Steam into Hydrocarbon Streams

E8.1 Failures have been reported when liquid water entered a hydrocarbon stream that was either hot or being heated. The water flashed to steam with a large, rapid increase in volume and pressure resulting in a rupture of the piping or vessel.

E8.2 The addition of steam to hydrocarbon streams is the largest user of steam in many refineries and one of the potential areas to add contaminants to the hydrocarbon stream. The quality of the steam must be maintained to prevent additional corrosion issues. Possible steam contaminants are CO₂, O₂, NH₃, sodium, and various amines. Most of these contaminants are in low enough quantities that they do not become an issue.

E8.3 The locations and specific installations for steam injection into the process are too numerous to describe in this standard; therefore, only the basic concepts that are central to most of the installations are discussed. In all cases, care should be taken to maintain an adequate pressure and temperature differential between the steam and the hydrocarbon stream to prevent steam condensation in the mixing elbow, quill, and/or spray nozzle.

E8.4 Steam Quality

E8.4.1 Steam should always be generated using high-quality (low-solids) deaerated or demineralized water and when attemperated, only high-quality deaerated boiler feed water without chemical additives should be used.

E8.4.2 The softening processes or demineralization may purify the water, and no preference is given to either one for pressures up to 4,000 kPa (600 psig). Boilers with pressures above 4,000 kPa (600 psig), require demineralized water.

E8.4.3 Contamination typically occurs from the process condensate, steam system corrosion control chemicals, corrosion products in the condensate system, and from ingress in the condensate system at condensate pots and pumps.

E8.5 Location

A comprehensive list of refinery injection locations is beyond the scope of this standard. Injection point locations vary with system design and operation. The injection location should be far enough upstream to ensure adequate mixing and distribution, typically 10 to 20 pipe diameters upstream from the first change in piping direction or entering a process vessel. Steam should be injected in the direction of process flow, and not perpendicular to it.

E8.6 Equipment

E8.6.1 Steam should be injected into piping co-currently into the middle of the process stream through a mixing quill or spray nozzle to promote good distribution and mixing in the entire pipe diameter, without impinging on the pipe wall. Steam also may be injected directly into the process equipment through nozzles, spray nozzles, and spargers.

E8.6.2 Injection equipment typically is constructed of a corrosion-resistant alloy (such as UNS S31603 or higher), and inspected each turnaround for erosion or corrosion at the spray tip. Carbon steel is normally adequate for piping and other injection system components.

E8.6.3 If steam is injected into a gas or vapor stream, a spray nozzle shall be used. The nozzle shall have a pressure drop high enough to prevent liquid water from carrying over into the hydrocarbon stream.

E8.6.4 The design also shall take into consideration the possibility of flash condensation and accelerated corrosion if the steam comes in contact with a cooler wall of the pipe.

E8.6.5 If liquid water injected into the process could cause damage or equipment failure, a steam trap located just upstream from the injection point should be used to remove water from the steam. Steam venting systems also have been used to eliminate liquid water before injecting it into the hydrocarbon stream.

E9 Chlorine into Catalytic Regeneration Systems

E9.1 Process Design

E9.1.1 Liquid-phase chloriding agents, such as organic chloride compounds, have been preferred because HCl gas is more difficult to inject into the stream, and because of its toxic and corrosive nature.

E9.1.2 In many catalytic reformers, chlorinated hydrocarbons, such as trichloroethylene (TCE) or perchloroethane (PCE) are continuously injected ahead of the reactors to maintain catalyst activity by replacing chloride lost from the catalyst during operation. Upon being injected into the hot process stream, these chloriding agents decompose into HCl and hydrocarbon, and the HCl adsorbs onto the reactor catalyst.

E9.1.3 Chloriding can be done either continuously or intermittently. The chloride adsorbed on the catalyst acts as an acid site for the reaction.

E9.2 Chloriding Agent Quality

E9.2.1 The agents are shipped as a very high-quality clean product.

E9.2.2 Tank blanketing should be maintained while in operation and during outages to avoid contamination from oxygen or water, which may cause corrosion at or downstream from the injection point.

E9.3 Location

E9.3.1 Mixing quills should be placed in the piping, immediately ahead of the reactors or on the feed side of the heater. The quill shall be pointed downstream to prevent mixing in the quill that may result in quill failure during operation.

E9.3.2 Mixing quills may be installed downstream from the heaters to avoid accumulation of chlorides in the heater tubes, mitigating chloride-induced SCC.

E9.3.3 The mixing quill should be near the center of the flow to mitigate the chloriding agent flowing along the pipe wall and to improve mixing.

E9.3.4 It is important that the process be hot enough at the injection point to decompose the chloriding agent and form HCl and mix the stream before reaching the catalyst.

E9.3.5 The location should allow access to the injection point for routine monitoring and maintenance. The mixing quill may be installed downstream from the heaters to avoid accumulation of chlorides in the heater tubes, mitigating the risk of chloride-induced SCC of equipment.

E9.3.6 The injection quill and related piping should be fabricated of UNS N06600 because of its low susceptibility to chloride SCC. The injection equipment (tanks, meters, pumps, and piping) may be made of UNS S31603 stainless steel. However, because of exposure to moisture during downtimes, components made from this alloy have been susceptible to chloride-induced SCC in this service.

E9.3.7 Carbon steel has been successfully used for the equipment in this service. It is critical that no moisture enters the system during down time or the carbon steel experiences a high corrosion rate.

E10 Hydrogen Mixing and Hydrogen Quench Systems

E10.1 Process Design

E10.1.1 In sulfur removal sections upstream of hydrogen reforming units, the ratio of hydrogen to hydrocarbon is relatively small. In this service, hydrogen can be added directly into the hydrocarbon stream.

E10.1.2 The local metal temperatures at the injection point shall not exceed the design temperature of the process line. Introduction of hydrogen into the process stream can result in localized hot spots, possibly promoting a local reduction of strength below the allowable fabrication code value.

E10.1.3 When mixing colder streams (quench hydrogen), heat conduction from the hot process stream pipe back into the cooler hydrogen stream piping shall be considered. The pipe material specification break shall be at a location where the metal temperature in the hydrogen feed stream is below the threshold for high-temperature hydrogen attack (HTHA) at the design hydrogen partial pressure.

E10.1.4 If there is a significant temperature difference between hydrogen and the hydrocarbon, a concern for thermal fatigue may exist if the quenching is intermittent. If the temperature difference is greater than 167 °C (300 °F), the use of an internal thermal sleeve should be considered.

E10.1.5 The use of static mixers downstream from injection points can minimize the effects of differential temperatures on downstream piping and equipment and improve mixing.

E10.2 Hydrogen Quality

E10.2.1 In hydroprocessing units, make-up hydrogen should be injected between the effluent air cooler and the cold high-pressure separator. The make-up hydrogen may contain HCl that can cause downstream corrosion problems. This injection point allows absorption of HCl into the water phase, and chlorides exit the separator with the sour water, while hydrogen exits the top of the separator. In some cases, it may be necessary to up-alloy the injection point area to minimize corrosion.

E10.2.2 The hydrogen quality may be improved by use of a membrane separation hydrogen recovery unit that increases the purity. This high-purity hydrogen can then be used as the entire supply, or more typically, as a slip-stream that is mixed with the other feed hydrogen.

E10.3 Injection Location

E10.3.1 The hydrogen injection point should be installed in a straight pipe run, with a minimum of 10 to 20 pipe diameters upstream from the first change of direction.

E10.3.2 In ferritic steel piping systems containing corrosive hydrocarbons, locating the hydrogen addition point near changes of direction such as piping elbows can promote higher localized corrosion rates.

E10.4 Equipment

E10.4.1 Hydrogen feed for hydrotreating should be introduced using a mixing quill, oriented in the direction of the fluid flow. The length of downstream pipe should allow adequate mixing of the hydrogen or a static mixer should be installed.

E10.4.2 If a quill is not used, the use of a thermal sleeve is required. The thermal sleeve acts to lengthen the conduction path for heat, lowering temperature of the pressure boundary materials, mitigating HTHA concerns in low-alloy steels and carbon steels. The thermal sleeve also minimizes the potential for thermal fatigue.

E10.4.3 There are many different designs for hydrogen injection equipment that require different materials and configurations. In all cases, the materials of construction shall meet API 941 ("Steels for Hydrogen Services at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants") to resist HTHA. In applying API 941, the local metal temperature at the design hydrogen partial pressure should be used during selection of materials of construction.

E10.4.4 Materials used in injection service associated with catalytic reforming units should be selected on a basis of high-temperature strength and resistance to HTHA. Low-alloy steels (e.g., 1-1/4 Cr-1/2 Mo and 2-1/4 Cr-1 Mo) should be used.

E10.4.5 Corrosion-resistant alloys should be considered when corrosion as a result of contaminants in the hydrocarbon feed stream is of concern.

E10.4.6 If corrosion resistance is required, hydrogen may be delivered using UNS S34700 or UNS S32100 SS, since they have good strength at elevated temperatures and are less susceptible to sensitization than UNS S30403 or UNS S31603 SS.

E10.4.7 In high-temperature hydrogen services the presence of naphthenic acids requires a minimum of 2.5% molybdenum. If strength considerations do not permit the use of UNS S31703 or carbon steel with stainless steel overlay, UNS S34700 SS that is weld overlayed with UNS S31700 stainless steel has been used. This composite structure has the strength of the carbide-stabilized alloys and the corrosion resistance of the molybdenum-containing grades.

E10.4.8 Fracture toughness, and thus the fatigue resistance of materials in hydrogen service, is lower than that in nonhydrogen service. The mixing apparatus configuration should be designed to minimize notches (stress intensity) and resist crack initiation as a result of alternating pressure and temperature of the process stream.

E11 Antifoaming Agents

E11.1 Antifoaming and defoaming agents in amine systems are typically silicones and polyols that break down foam and inhibit the stabilization of the bubbles. Suspended solids in amine units from mill scale, iron oxide, amino acids, and heat-stable salts can cause corrosion and erosion of process equipment, and fouling and plugging of downstream process equipment. Foaming of lean amine solutions is caused by surfactants but can be more severe when suspended solids are present. Some plants have included process control, using pressure transmitters to measure differential pressure, and when the differential pressure (DP) in the amine absorber increases to a level above a threshold value, the pumps are energized, dosing the unit with antifoam chemicals.

E11.2 In DCU, foaming occurs because of the asphaltenes and resins in the system that act as foam stabilizers. Foam carryover into downstream equipment has caused plugging and fouling, and thus has reduced refinery unit efficiencies. The injection of polysiloxane compounds can be used to inhibit foam formation in the DCU. The amount of antifoam used in the DCU should be kept to a minimum as the resultant silica compounds may adsorb on, and deactivate catalysts in downstream hydroprocessing units.

E11.3 Process Design

E11.3.1 Most antifoaming agents are injected neat without diluents.

E11.3.2 Antifoams have a limited shelf life depending on the type.

E11.3.3 Filters may be used within the installation to limit contamination with polyol antifoams, and also used as guard beds to adsorb silicon compounds.

E11.4 Location

E11.4.1 In the acid gas recovery units, the antifoam chemicals should be injected into the lean amine system upstream from the amine absorber vessel. If the antifoam is injected into the suction of the lean amine booster pump to improve mixing, no mixing quill is required.

E11.4.2 Defoamers have been added to the coke drum hydrocarbon nozzles in the side of the coke drum and at the top of the drum(s) to inhibit fouling of downstream equipment. Maintenance of the nozzles is a primary design concern for selection of injection nozzles and their location. Side nozzles can effectively spray the defoamer at the foam head, but they tend to foul easier than the top nozzles. Top nozzles are more commonly used because of fouling. The injection pipes in a top installation should be positioned to minimize carryover into the outlet vapor stream.

E11.5 Equipment

E11.5.1 The antifoam agents are not typically corrosive, so the materials for construction of equipment should be based on the minimum pipe specification for the stream where the chemical is injected.

E11.5.2 No mixing quill or mixers are required for antifoam injection into the suction of lean amine booster pumps. Generally, antifoams work better with larger droplet size so the mixing should be done for equal distribution and not for making small bubbles. High-shear situations should be avoided as they can deactivate the antifoam.

E11.5.3 The typical DCU injection device nozzle is fabricated from a straight pipe with 90° cut at the end. Injection quills that extend into the coke drums have been damaged during the coke cutting operation, and should not be used.

E12 Process Mix points

E12.1 Heat Exchanger Bypass Piping

E12.1.1 Purpose/Overview

E12.1.1.1 Heat exchanger bypass piping has been a known source of problems in heat recovery trains that contain both liquid and vapor phases. Corrosion and fatigue occur where a controlled bypass regulates the temperature of heat exchanger effluent streams. The two scenarios can be looked at as a hot stream bypassing a cooler and being mixed with the colder stream or a cold stream bypassing a heater and being mixed with the hotter stream.

E12.1.1.2 Either of the scenarios can result in corrosion or serious fluid flow disturbances. Thermal fatigue may be an issue when the two mixing streams have a temperature difference greater than 167 °C (300 °F), although problems have been identified in corrosive services when the temperature differential has been as low as 50 °C (122 °F). Also, mechanical fatigue cracking can be promoted by streams of two phases that create a hydraulic hammer from collapsing bubbles or slug flow. If cooler liquid water or hydrocarbon is being mixed with the high-temperature stream, rapid flashing can occur. The resulting increase in pressure and volume may result in lifting pressure-relief devices or equipment failure.

E12.1.1.3 Corrosion can occur from precipitation of salts and/or solids from the streams, flash condensation, local acid attack, or attack from reactive gasses. The bypass also may result in liquid water dropping out of one of the streams. The corrosion and fatigue may be combined into corrosion-assisted fatigue where the two elements accelerate the damage.

E12.2 Process Design

E12.2.1 The bypass design should look at all flow scenarios for potential corrosion or flow disturbances. This should be done at all flow and temperature ranges in the design.

E12.2.2 Installation of static mixers or thermal sleeves may be required to mitigate corrosion or thermal fatigue.

E12.3 Injection Location

E12.3.1 The streams typically meet at a pipe tee and mix without aid of additional devices (e.g., thermal sleeves or static mixers).

E12.3.2 If possible, the hot stream should enter through the branch of the tee, mixing with the cooler stream entering one leg of the two main branches.

E12.3.3 The two streams should not meet head-to-head in the tee.

E12.4 Equipment

E12.4.1 As a minimum, exchanger bypass piping shall follow the pipe specification of the more corrosive service.

E12.4.2 If corrosion in the mixed stream is higher than either of the original streams, higher-alloy stainless steel (UNS S31803/S32205) and nickel alloys (UNS N06625) should be chosen to mitigate potential damage.

E12.5 Mixing Streams of Different Chemical Compositions

E12.5.1 When streams with different chemical compositions are introduced, the compatibility of these streams must be well understood to provide a satisfactory design. The streams may initially have the same physical characteristics (e.g., temperature, pressure), but reactions such as heat of mixing or precipitation may result in temperature changes that can change the local corrosion rates. Additionally, these changes can affect the flow regime, and may produce changes that result in deposition and fouling (see Appendix A).

E12.5.2 Changes in the physical properties of the stream may result in precipitation/condensation of corrosive species that were not stable in the parent streams. This scenario can produce severe metal loss depending on concentration and temperature.