

Integrity Operating Windows

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Introduction

In today's operating environment, it is not enough to base future inspection plans only on prior recorded/known history of equipment condition. A fundamental understanding of the process/operating conditions and resulting damage mechanisms are required to establish and maintain an inspection program that yields the highest probability of detecting damage. Inspection plans should be dynamic and account for changing process conditions and current equipment condition. A fundamental step is to frequently rationalize and align the developed degradation knowledge base of the materials of construction with the operation of the equipment, its inspection history, measured corrosion rates and known industry problems. Whether utilizing time-based or risk-based methodology for determining inspection intervals, Integrity Operating Windows (IOWs) are useful to identify and track process information that either validates or might cause changes to existing inspection plans.

In order to maintain the integrity and reliability of pressure equipment in industry, multiple process safety management (PSM) systems may be necessary. Many of those management systems are oriented toward having a rigorous inspection program, as well as the supportive engineering activities. This may include the implementation of IOWs which can supplement process safety and inspection programs by identifying key process parameters potentially affecting mechanical integrity.

In addition to the application of industry codes, standards, and recommended practices, a number of other PSM systems are vital to support a rigorous inspection and mechanical integrity program in order to predict/avoid/prevent pressure equipment damage/corrosion; leaks and failures; and improve reliability. Three key elements of those supporting PSM programs include:

- the establishment, implementation, and maintenance of IOWs. See paragraph 3.6;
- an effective transfer of knowledge about unit specific IOWs to all affected personnel; and
- an effective MOC program to identify any changes to the process or the physical hardware that might affect the integrity of pressure equipment.

In order to operate any process unit, a set of operating ranges and limits ~~needs to~~ should be established for key process variables, to achieve the desired results (i.e. product within specification, safe operation, reliability, etc.). These limits are generally called operating limits or operating envelopes. IOWs are a specific subset of these key operating limits that focus only on maintaining the integrity or reliability of process equipment. Typically, IOWs address issues that involve process variables that, when not adequately monitored or controlled, can impact the likelihood and rates of damage mechanisms, which may result in a loss of containment.

For purposes of this document, maintaining the integrity of the process unit means avoiding breaches of containment, and reliability means avoiding malfunctions of the pressure equipment that might impact the performance of the process unit (meeting its intended function for a specified time frame). In that sense, integrity is a part of the larger issue of pressure equipment reliability, since most breaches of containment will impact reliability. IOWs are those preset limits on process variables that need to be established and implemented in order to prevent potential breaches of containment that might occur as a result of not controlling the process sufficiently to avoid unexpected or unplanned deterioration or damage to pressure equipment. Operation within the preset limits should result in predictable and reasonably low rates of degradation. Operation outside the IOW limits could result in unanticipated damage, accelerated damage and potential equipment failure from one or more damage mechanisms.

Pressure equipment is generally fabricated from the most economical materials of construction to meet specific design criteria based on the intended operation and process conditions. The operating process conditions should then be controlled within preset limits (IOWs) to avoid unacceptable material degradation and achieve the desired economic design life of the assets.

A properly structured, efficient, and effective inspection program may be supplemented (made more effective) by IOWs being established and implemented to adjust and improve inspection planning and to avoid unanticipated impacts on pressure equipment integrity. Inspection plans are typically based on historic damage mechanisms and trends and are not generally designed to look for unanticipated damage resulting from process variability and upsets. Inspection plans generally assume that the next inspection interval (calculated based on prior damage rates from past operating experience) are scheduled based on what is already known and predictable about equipment degradation from previous inspections. Without a set of effective and complete IOWs and feedback loop into the inspection planning process, inspections might need to be scheduled on a more frequent interval just to look for anything that might potentially occur from process variability.

Integrity Operating Windows

1 Purpose and Scope

1.1 The purpose of this recommended practice (RP) is to explain the importance of IOWs for process safety management and to guide users in how to establish and implement an IOW program for process facilities. Its express purpose is to minimize unexpected equipment degradation that could lead to loss of containment. It is not the intent of this document to provide a complete list of specific IOWs or operating variables that might need IOWs for the numerous types of ~~hydrocarbon~~ process units in the industry (though some examples are provided in the text and a list of process variables for some example process units is included in Annex A); but rather to provide the user with information and guidance on the work process for development and implementation of IOWs to help strengthen the Mechanical Integrity (MI) program for each process unit.

The key goals of an IOW program are:

1. Defining IOW limits which will result in predictable and acceptable levels of equipment degradation to meet reliability expectations.
2. Enabling effective communication of equipment limits and exceedances between key Process, Operations, Maintenance, and other MI stakeholders to facilitate safe and reliable process operation and management.
3. Facilitating the reliable operation of equipment without ~~loss of containment or the need for~~ unplanned maintenance activities between scheduled outage or shutdowns.

1.2 The scope of this standard includes:

- definitions of IOWs and related terminology;
- creating and establishing IOWs;
- data and information typically needed to establish IOWs;
- descriptions of the various types and levels of IOWs needed for process parameters;
- risk ranking IOWs;
- documenting and implementing IOWs;
- monitoring and measuring process variables within established IOWs;
- communication of IOW exceedances;
- reviewing, changing, and updating IOWs;
- integrating IOWs with other risk management practices;
- roles and responsibilities in the IOW work process; and
- knowledge transfer to affected personnel.

1.3 This RP outlines the key elements in defining, monitoring and maintaining IOWs as a vital component of integrity management (materials degradation control) and assisting in the inspection planning process, including Risk-Based Inspection (RBI). Other Process Safety systems may be affected by or involved with the IOW program, including management of change (MOC), process safety information (PSI), and training. For purposes of this RP, these systems are only addressed to the extent of mentioning the integration aspects that are needed with the IOW program.

1.4 This RP does not cover operating windows established for normal process control, such as for the purpose of maintaining product quality. It also does not cover operating windows for other PSM issues, including avoidance of operating error, that do not relate to control for the purpose of maintaining equipment integrity and reliability. However, IOWs should be integrated into a common system for managing all operating variables and limits.

Examples of equipment types, damage mechanisms and operating conditions that are typically not addressed by IOWs:

- **Design limits for vessels and piping (i.e., design pressure and temperature limits).**
- Rotating equipment, instrumentation, and electrical hardware. IOWs established within the scope of this RP typically cover only fixed equipment, but can be extended to other types of equipment at the option of the site. Product quality or product specification limits.
- Some damage mechanisms that can occur or are strongly influenced by unanticipated short-duration upsets are not typically controlled by IOW limits. They are controlled by proper materials selection, design, by operations and /or maintenance procedures. Examples include:
 - Brittle fractures that may occur during hydrotest
 - Stress corrosion cracking (SCC) of sensitized stainless steels at downtimes controlled by soda ash treatment,
 - Chloride SCC at low point drains in stainless steel equipment during unit start-ups controlled by pre-start-up draining and drying of stainless systems.

2 Normative References

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) applies.

1. API Recommended Practice 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*
2. API Recommended Practice 581 Risk Based Inspection (3rd Ed, Second Addendum Part 2 Annex B “Determination of Corrosion Rates”, 10/2020)
3. API Recommended Practice 970, *Corrosion Control Documents*
4. ~~ANSI/ISA-18.2, *Management of Alarm Systems for the Process Industries*~~
5. ~~ISA-84.00.01, *Functional Safety: Safety Instrumented Systems for the Process Industry*~~
6. API 579-1/ ASME FFS-1, (Annex 2B)
7. ASME PCC-3 Inspection Planning Using Risk-Based Methods (Chp 6 Damage Mechanisms and Failure Modes)

3 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1 Alarms

An audible sound (e.g. horn, buzzer, beep, etc.) along with a visual signal (e.g. flashing light), in the control room that alerts operators to a deviation in a process condition that may require immediate attention.

3.2 Alerts

A secondary level of communication to key stakeholders (i.e. operations, technical SMEs) that signifies a condition that will need resolution to avoid a potential operating condition that could lead to process safety or reliability impacts.

NOTE 1 Generally, alerts can be addressed over a longer time than alarms. Alerts may include visual signals, and/or audible sounds, and/or other real-time process tracking charts/graphs with limits identified, e-mail notifications, etc.

NOTE 2 For this RP, alerts are related primarily to Standard IOW limit exceedances but may also be implemented for Informational IOWs.

3.3 Corrosion Control Document (CCD)

A document or other repository or system that contains the necessary information to understand materials damage susceptibility issues in a specific type of operating process unit at a plant site.

NOTE: Generic CCDs can also be developed that provide generic guidance upon which to build a unit-specific CCD, but generic CCDs are not as useful as unit-specific CCDs that are based on actual hardware configurations, actual process conditions and actual materials of construction.

NOTE: See API RP 970 "Corrosion Control Documents" which outlines a work process for development and maintenance of CCDs.

3.4 Corrosion Materials Diagram (CMD)

A modified process flow diagram (PFD) or database list containing relevant equipment and piping damage mechanisms, operating conditions, materials of construction, systems/circuits, and other information that ~~the CCD Team may be determined~~ to be useful for each portion of a process unit, ~~as well as the usual PFD information.~~

3.5 Corrosion Materials Specialist

A person acceptable to the operator-user who is knowledgeable and experienced in the specific process chemistries, degradation mechanisms, materials selection, corrosion mitigation methods, corrosion monitoring techniques and their impact on equipment.

3.6 Integrity Operating Window (IOW)

Established limits for process variables (parameters) that can affect the integrity of the equipment if the process operation deviates from the established limits for a predetermined length of time (includes Critical, Standard and Informational IOWs).

3.7 IOW Critical Limit

An established IOW level that if exceeded could result in rapid deterioration such that the operator is required to take immediate predetermined actions to return the process variable back within the IOW to prevent significant defined risks of potential equipment damage or hazardous fluid release.

NOTE Other terminology has been used in place of critical limit, such as safe operating limit or safety critical limit.

3.8 IOW Standard Limit

An established IOW level defined as one that if exceeded over a specified period of time could cause increased degradation rates or introduce new damage mechanisms beyond those anticipated.

NOTE: Other terminology for standard limits has been used such as key operating limit or reliability operating limit. Since the timing of the impact from an exceedance of a IOW Standard Limit can vary significantly, the notification and response to an exceedance can also vary. For higher risk exceedances, alarms or alerts are potentially needed and the operator may have some predetermined actions to take. For lower risk exceedances, alerts may only be needed for eventual interaction with operating supervisors or appropriate technical personnel and subject matter experts (SMEs).

3.9 IOW Informational Limit

An IOW Informational limit is a parameter that may be used to predict a change in corrosion potential. It may simply be trended rather than having a specified limit or range. Informational IOWs are used for parameters that cannot be controlled by operators."

NOTE Other terminology can be used in place of an IOW Informational Limit, such as corrosion control limit or reliability limit.

3.10 Management of Change (MOC)

A documented management system for review and approval of changes in process, equipment or piping systems prior to implementation of the change.

NOTE For purposes of this RP, MOC may apply to making changes to or creating IOWs.

3.11 Mechanical Integrity (MI)

The management systems, work practices, methods, and procedures established in order to protect and preserve the integrity of operating equipment i.e. avoid loss of containment because of equipment damage mechanisms. MI is typically one part of a process safety program.

3.12 Notifications

A message to an operator and/or SME that an IOW exceedance has occurred which may not necessarily have an alarm associated with it but may require a specific required action and response from an operator or SME.

3.13 Operating Limits / Envelopes (OEs)

A set of operating ranges and limits established for key process variables to achieve the desired results (i.e. product within specification, safe operation, reliability, etc.).

NOTE: IOWs are a specific subset of these key operating limits that focus only on maintaining the integrity or reliability of process equipment that can be affected by credible damage mechanisms that may occur in the process unit.

3.14 Process Flow Diagram (PFD)

A simplified diagram of a process unit showing the main pieces of equipment and piping, with limited details of process design parameters.

3.15 Process Hazards Analysis (PHA)

A work process to assess and document the hazards and risks associated with operating a process unit, and to make recommendations on what actions may be necessary to mitigate unacceptable risks.

3.16 Process Variables

Parameters of the process fluids (chemical and physical) and equipment operational parameters (e.g. metal temperature) that need to be controlled.

3.17 Process Safety Management (PSM)

The implementation of all the work practices, procedures, management systems, training, and process safety information that are necessary in order to prevent the release of hazardous substances from process equipment.

3.18 Pressure Equipment

Stationary, static, or fixed equipment for containing process fluids under pressure, which for the purpose of this document does not include rotating equipment.

EXAMPLE Pressure equipment includes, but is not limited to such items as piping, vessels, heat exchangers, reactors, tanks (static head pressure), pressure relief devices, columns, towers, heater tubes, and filters.

3.19 Rationalization (Alarm Rationalization)

Rationalization is the process of ensuring an alarm meets the requirements set forth in the alarm philosophy, including the tasks of prioritization, classification, settings determination, and documentation.

3.20 Risk-Based Inspection (RBI)

A risk assessment and management process that is focused on inspection planning for loss of containment of pressurized equipment in processing facilities, due to material deterioration. These risks are managed through inspection and IOW monitoring in order to influence the probability of failure.

3.21 Subject Matter Expert (SME)

One who has in-depth knowledge and experience on a specific subject as it relates to IOWs and is considered acceptable to the Operator-User.

NOTE: Various SMEs are necessary to establish IOWs for each process unit, e.g. corrosion/materials SME, process SME, operations SME, equipment type SME, inspection SME, etc.

3.22 Stakeholder

An individual, group, or organization that may affect, be affected by, or perceive itself to be affected by, the IOW issue.

3.23 Total Acid Number (TAN)

A measure of various acids, including organic acids, in hydrocarbon streams. This is typically determined via an ASTM procedure involving titration of a hydrocarbon sample.

3.24 Work Process

A series of activities or steps aimed at achieving a set objective, with inputs and outputs. e.g. the IOW work process to establish IOW limits on operating parameters.

4 Parameters that May Require Different Types and Levels of IOWs

Parameters that may influence the mechanical integrity or reliability of the equipment fall into two types: chemical and physical. IOWs should also be classified in different levels, based on risk, to prioritize notifications (including alarms, alerts, and other notifications) and timing of actions needed when IOWs are exceeded. In this RP, three primary levels of IOWs: “critical”, “standard”, and “informational”, are described based on the predicted change in damage rate to equipment during an exceedance and the ability of the operator to take corrective action.

4.1 Chemical and physical parameters noted below are not all inclusive but provide examples of the process parameters that may need IOWs established.

4.1.1 Chemical parameters are those that relate to the chemistry and fluid content of the process. Examples include pH, water content, acid gas loading, sulfur content, salt content, NH₄HS content, NH₃ content, TAN, acid strength, amine strength, inhibitor concentration, chloride contamination levels, oxygen content, etc.

4.1.2 Physical (mechanical, operational) parameters are those that are not chemical in nature but include all other aspects of a process design that are vital to maintaining control within established design parameters. Examples include design and operating pressure and temperature, partial pressures, dew points, dry points, heating and cooling rates, delta pressure, flow rates, injection rates, inhibitor dosage, amperage levels, slurry contents, hydrogen flux, vibration limits, corrosion probe measurements, etc.

4.2 IOWs should be classified into three levels, “critical”, “standard”, and “informational”, as follows:

4.2.1 A Critical IOW level requires the operator to urgently return the process to a safe condition to avoid a large loss of containment of hydrocarbons or other hazardous fluids, or result in an emergency or rapid non-orderly shutdown.

Typically, Critical IOW limits will have control room alarms, alerts or other immediate notifications to the operator that a limit has been exceeded.

4.2.2 A Standard IOW level requires predetermined operator intervention or corrective action by a SME if the duration of the exceedance is more than a specified time (typically the duration that could cause increased degradation rate or that could introduce new damage mechanisms beyond those anticipated) in order to avoid one or more of the following:

- an eventual loss of containment,
- a release of hydrocarbons or hazardous fluids,
- an unscheduled or non-orderly shutdown,
- a negative impact to the long-term unit performance and its ability to meet outage or shutdown turnaround run length.

4.2.3 Informational IOW limits, often less restrictive limits for Critical and Standard IOW limits, are for trending by the SME and may not be controllable by operations. An effective IOW program should include Informational IOW limits. Informational limits may be an indicator that damage will occur. Deviations from Informational IOWs could lead to accelerated corrosion or other damage over a longer period. Informational IOW parameters may provide secondary or circumstantial indication of active corrosion/ erosion. For example, in an atmospheric tower overhead, the primary process control parameter for corrosion in the reflux may be the pH of the condensate, and a secondary informational parameter may be iron content measured periodically by laboratory sampling. When Informational IOW limit exceedances occur, the appropriate SMEs may specify that engineering, process, or inspection activities be planned or adjusted to control the rate of deterioration and prevent unacceptable equipment deterioration over the longer term. Informational IOWs typically do not have alarms or alerts associated with exceedances. In most cases, the limits for informational parameters initiate a notification to the appropriate SME. Informational IOWs are typically associated with the following situations:

- would not be directly related to a potential loss of containment within the near term,
- provides for a secondary indication of operational performance or corrosion control issue, and/or
- used to track parameters that are not necessarily controllable by operators.

4.3 The primary difference between a critical and a standard limit is in the reaction time allowed (and necessary) to return the process to within the IOW limits. For critical limits, there will typically be visual and audible alarms for the operators and typically all Critical Limits would require specific predetermined actions to be taken by the operator to urgently return the process to within the IOW limits. In some cases, there may also be instrumented

shutdown systems that automate a sequence of steps to regain control of the process. For some standard limits, there may also be visual and/or audible alarms, depending upon the level of risk and required response time associated with the IOW. A risk assessment process such as that outlined in 5.8 and Section 6 can be used to determine the need for what alerts and alarms are appropriate for each IOW. Standard limits can in many cases be more conservative limits for operating parameters than critical limits in order to provide the operator with more time and options to bring the process back within the IOW limit before the more urgent measures for exceeding a critical limit are required.

4.4 In addition to the predetermined operator intervention required for critical limits and potentially some standard limits that are exceeded, notification to designated SMEs should be designed into the IOW work process so that technical investigations and corrective actions can be implemented to prevent further exceedances. Notifications should include designated inspectors, corrosion/materials specialists, process engineers and others other appropriate personnel in case inspection plans, corrosion management strategies or process conditions need to be adjusted.

4.5 Figure 1 illustrates how various types of operating limits might create boundaries for any specific operating window. The middle zone between the standard limits (high and low) is the zone designated for achieving operational targets. Outside of those limits, operator intervention is generally required to return the process into this zone. Some limit ranges may not have an upper or lower boundary, depending on the variable. For example, heater tube-skin temperatures generally have upper limits, but most times has no lower limit.

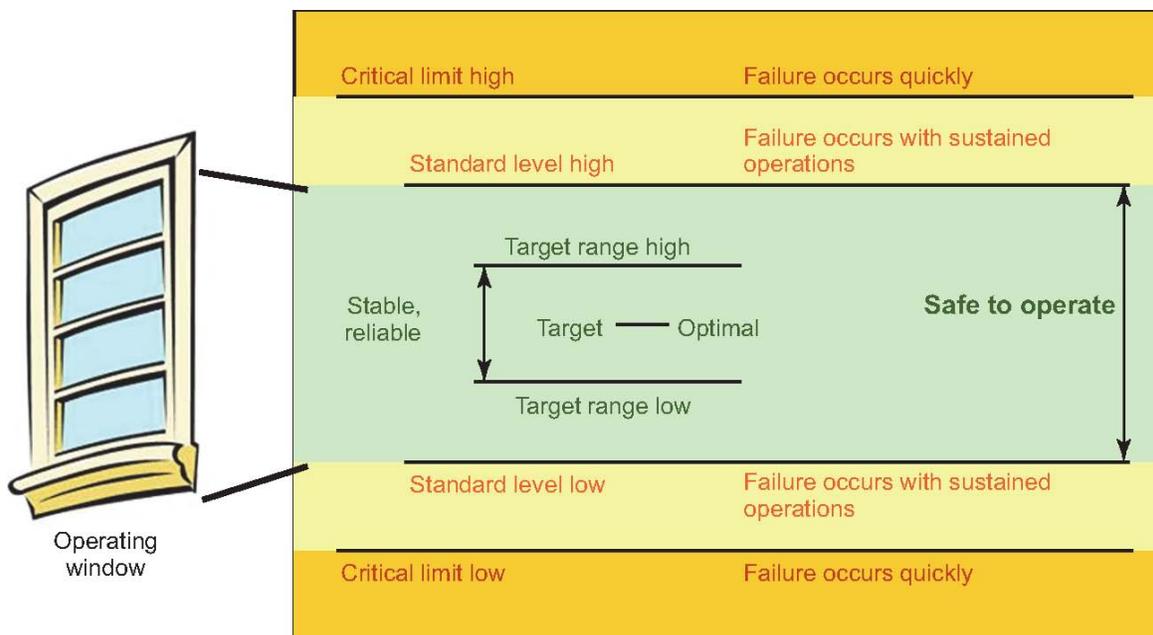


Figure 1—Zones of Operation Including Target Ranges with Standard and Critical Limits

5 IOW Work Process

5.1 In this section a general work process is outlined for identifying IOWs, setting appropriate limits relative to a defined premise and integrating IOWs into the site’s mechanical integrity program. Additional details on the type and levels of IOWs are outlined in Section 4 and Section 6. For a specific example that closely follows the flow outlined in this section for one specific piece of equipment, see Annex C. General guidance and considerations for identifying and setting appropriately conservative limits is outlined in Section 9. Note that this work process may be applied to a single equipment item, multiple equipment items in a group (corrosion circuit) or more generally to the overall process unit. As an example, a chart reflecting a work process for setting IOWs

is provided in Figure 2 (below). Note the operator-user should develop and document their specific work process which may differ from this figure.

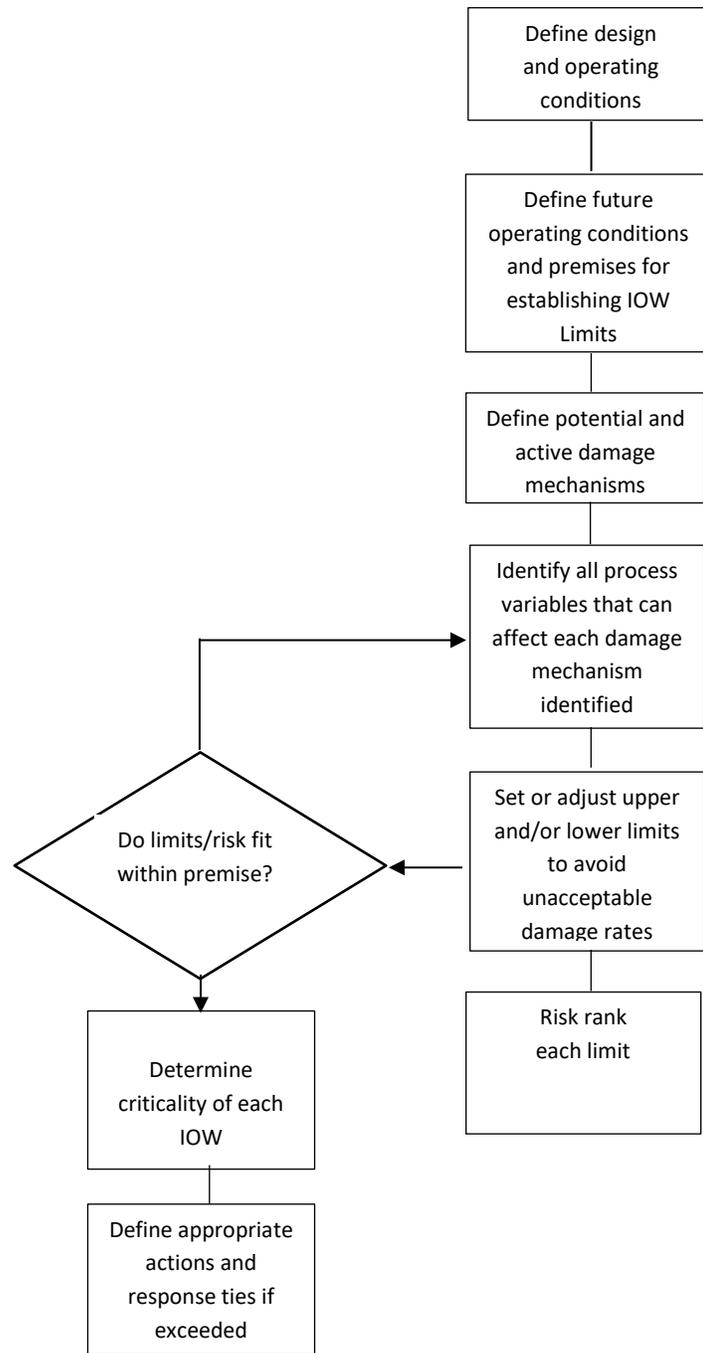


Figure 2—Example IOW Development Work Process

5.2 Step 1 in the process is to review the existing mechanical design conditions and prior operating conditions. Other operating conditions such as upset, startup, shutdown, catalyst regeneration, decoking, hydrogen stripping, etc. and service type such as continuous, intermittent or irregular should also be considered. The identification of the credible damage mechanisms in 5.5 requires a fundamental understanding of the mechanical design, the process operating conditions (temperatures, pressures, service, inhibitors, etc.) and the materials of construction including the alloy and material grade, method of fabrication, prior thermal and mechanical treatments, etc. Consideration should be given to both the normal operation and any abnormal operation that could produce unanticipated damage mechanisms and/or accelerated damage rates.

5.3 Step 2 is to define a “premise” or basis for establishing IOW limits. Typically, the premise is established on a unit specific basis, however, in some cases a premise may be needed for an individual piece of equipment that may experience significant operational changes. The premise should define and document the following type of information:

- Planned outage or shutdown cycle or desired run length
- Anticipated future unit/equipment operating conditions
- Approach for determining operation limits (historical vs limiting component)
- Method for determining damage rates (estimated, measured or industry based calculated rates)
- Maximum targeted wall loss rates based on equipment types

Each premise is unique to the site or situation being considered and may include other types of information for definition, such as targeted risk levels, etc. A key consideration for establishing a premise is the time frame for which it will apply. In some cases, the established time frame may be very short (for example, for a specific operation to take advantage of an

opportunity feed stock) but, in general, the time frame should be based on an acceptable run duration or life for the equipment. When establishing standard or reliability-based IOWs, one or two outage or shutdown periods are typically selected for the duration. After the premise has been established and accepted, changes to the operation should be considered through an MOC process. For small or incremental operational changes, the effected equipment or circuits should be reviewed for accelerated damage due to the change (e.g. slightly higher sulfur in the feed stock to a refinery). Significant changes or exceedances in the IOWs during operation may need revalidation of the premise document and IOW limits. It is important that the consequences of the premises be vetted and agreed upon by the IOW team.

5.4 Step 3 is to identify the credible damage mechanisms that could occur in each piece of process equipment. Historical damage rate and future rate considering any planned changes in operation should be estimated. API RP 970 covering corrosion control documents (CCD) presents a work process for assessing damage mechanisms. Integrating the CCD work process with the IOW work process may provide a more efficient manner in completing these tasks. Section 7 and Annex A contains examples of damage mechanisms and potential operating variables within process units that may need IOWs established. There are several sources of industry data that identify typical damage mechanisms for various operating units, including:

- API RP 571 Damage Mechanisms Affecting Fixed Equipment in the Refining Industry
- API RP 581 Risk-Based Inspection Technology ([3rd Ed, Second Addendum Part 2 Annex B “Determination of Corrosion Rates”, 10/2020](#))
- API 579-1/ ASME FFS-1 (Annex 2B)

- ASME PCC-3 [Inspection Planning Using Risk-Based Methods \(Chp 6 Damage Mechanisms and Failure Modes\)](#).

Operating site programs that have been utilized to identify/establish equipment specific damage mechanisms and/or risk that should be considered during this process may include the following;

- Risk-based inspection studies;
- Corrosion reviews or similar programs, such as those establishing CCDs;
- Damage mechanism review studies
- Equipment risk assessments;
- Process hazards analysis (PHA) or hazards analysis and operability (HAZOP) studies.

5.5 Step 4, identifies key process variables related to activation or rate of progression of the damage mechanisms. The goal of the IOW program is to identify the key parameters to monitor and to set limits on controllable parameters that can be adjusted by operations to achieve the desired level of equipment integrity and reliability.

These variables may be leading or lagging indicators. Leading indicators are predictive while lagging indicators are reactive. Multiple variables may be leading indicators of the activation or rate of a damage mechanism. Desalter efficiency, pH, chloride content, conductivity, salt point, and dew point are examples of leading indicators of corrosion potential in a crude unit atmospheric tower overhead system. Iron content and corrosion probe response are examples of lagging indicators of corrosion potential in a crude unit atmospheric tower overhead system. The leading indicator parameter(s) most controllable and most effective at reducing the damage potential should be the primary variable(s) for monitoring and applying limits. In general, lagging indicators not directly controllable by the operator are typically considered as Informational IOWs.

~~Some variables may be codependent. Codependent operating variables interact to produce damage (e.g. temperature, reactive sulfur content and alloy are codependent variables that affect the high temperature sulfidation rate.~~

5.6 Step 5 is to set upper and/or lower limits to identify when new damage mechanisms are triggered or when degradation rates change significantly in relation to the inspection planning strategy.. Operation of a heater above the design tube metal temperature limit with the plan to retube this heater at the next planned outage is an example of a limit to indicate increased damage rate. Setting a maximum temperature limit to prevent high temperature hydrogen attack (HTHA) is an example of a limit above which a new damage mechanism is activated. Existing limits should be reviewed against the defined premise (see 5.3) to ensure they will achieve the desired reliability and mechanical integrity. Multiple aspects of each variable need to be examined when establishing operating limits. The following paragraphs of this section provide the most common aspects to consider during the analysis.

5.6.1 The accuracy, relevance and location of the measurement need to be considered (e.g. the measurement location may not be optimal for the damage location and the measurement accuracy may require a conservative limit to provide adequate response time.)

5.6.2 The limit needs to be set considering the rate of further damage progression expected. Note that the time needed to adjust the operation and the potential effect on inspection planning strategy needs to be considered. ~~The limit needs to be set considering the rate of further damage progression expected at the limit level selected,~~

5.6.3 The limits need to be set considering the level of risk for exceeding the limits. A process limit will be set with the level of notification needed (alarm, alert, e-mail, or other notification) and by establishing the predetermined response actions when that limit is exceeded.

5.6.4 Consideration should be given to setting multiple limits on some IOWs to provide more time and less urgent responses to bring the operation back within normal operation before reaching a Critical IOW limit. Some process variables could have an IOW Informational limit that would provide time for an SME to consider an appropriate response, a Standard IOW limit at a next level which may have a designated operator response, and a Critical IOW limit which would require an urgent operator or automated response. Limits should be rationalized and prioritized based on the site's standard ([see comments in Section 6.1](#)).

5.6.5 Some limits in reality involve multiple co-dependent variables not just a single target value for a single parameter. Many of the corrosion related damage mechanisms also have a significant time effect that needs to be considered. For example, the rate of high temperature sulfidation corrosion is dependent on; temperature, alloy type and amount of reactive sulfur present in the process stream influence. If a limit were to be set on temperature alone an exceedance may occur without any measurable damage to the equipment if there was insufficient time for measurable damage to occur.

5.7 Step 6, [in order to determine the level of the IOW \(Critical, Standard or Informational\), a risk ranking process may be used](#). In some cases, the relative risk may be determined subjectively, and in more complicated cases, the risk analysis may need to be more rigorous. Many operating companies have developed risk matrices and risk analysis procedures to provide guidance for consistent management decisions which may also be used to determine the risk of exceeding the established IOW limit. An example risk matrix and analysis process are provided in Section 6. Determining the IOW level and/or risk for a given parameter is important to help distinguish which parameters and limits:

- will need alarms versus alerts;
- will need predetermined actions to be taken to speed recovery times;
- will need formalized follow-up and investigation after exceedances occur;
- if changed or adjusted may need to be managed through a MOC process, etc.; and
- will need a review of the inspection strategy by the inspector or SME.

5.8 Step 7 Once the limits and relative risk ranking has been developed, the proposed limits should be [reviewed and validated by the Operator-User and compared](#) to the IOW premise developed in 5.3. The risk level for each parameter is often dependent (or codependent) on multiple factors and may need to be developed through an iterative process. In some cases, the existing sample points, instrument ranges, frequency of data acquisition, etc. may not be optimal, in which case the assumed risk based on that measurement limit may be higher than is desirable.

The intended business objectives for the run period should also be considered. For example, the consideration of achieving product yields or production rates may require a compromise between competing IOW limits, provided the risks associated with such compromises are acceptable to ~~all~~ stakeholders. This may be accomplished intuitively during the risk ranking process by continually testing a proposed limit level against the risk assumed at that level.

5.9 Step 8 After establishing the limits and risk, the levels of the IOWs (Critical, Standard, or Informational) can be established. As noted in 5.8, the selected level of IOW is used to distinguish which parameters and limits will need alarms, alerts or other type of notifications, as well as the required response actions and timing, per

5.10. The level is also linked to the need to determine the amount of documentation required, ownership of the IOW and necessary follow-up on exceedances that have been recorded.

5.10 The last box in the flow chart in Figure 2, Step 9, is to determine the actions needed with response time for IOW exceedance. Critical IOW limit exceedances will normally require an urgent specific response by the operator to avoid more rapid equipment degradation problems. Response time for Standard IOW exceedances will be less urgent than those associated with Critical IOW exceedances. Response times for both Critical and Standard IOWs should be defined and agreed upon by the IOW team. Some of those actions will likely be for operators, but other response actions may be for inspectors and/or designated SMEs. Response actions and associated timing by operators for IOW Informational limits will be mostly related to which inspector or SME should be notified in order to determine what response action is needed. The notification of and follow up action by the inspector or SME is the essential step in linking applicable IOW exceedances to the MI program and inspection planning process. Automated communication of exceedances to the appropriate stakeholders is the most effective method.

6 IOW Risk Ranking

6.1 In this section, an example risk ranking process and risk matrix are provided to guide the user through an evaluation of the importance and priority of each parameter/limit combination under consideration. As noted in Section 5, IOWs may be risk ranked to help determine the appropriate priority of alarms, alerts, notifications and response action. Risk assessment helps to determine what actions the operator needs to take and how fast the operator needs to act, i.e. the higher the risk, the sooner the operator may need to respond and the more definitive the response may need to be. Additionally, with higher risk, more levels of action might be designated for Standard IOWs to provide an increased chance of regaining control before a Critical IOW limit is reached. See Figure 6 showing an example where there might be more than one Standard limit for tube-skin temperature IOWs before reaching a Critical IOW limit. [Note that Operating companies should also refer to their existing alarm management and rationalization strategies.](#)

6.2 The risk for established IOW limits for a given operating parameter is a function of the event probability and consequence when the limit is exceeded. In each case or scenario, several sub-factors need to be considered when establishing the risk levels. An example approach to establishing three levels of IOWs (“Critical”, “Standard” and “Informational” limits) is outlined to separate IOWs for process parameters that have shorter term mechanical integrity implications from those that have longer term process safety or reliability implications. After designating the highest risk IOWs (i.e. critical limits) additional prioritization can be achieved through risk ranking of the “Standard” and “Informational” limits in order to identify those limits that need quicker, more definitive action by the operator or designated SME.

6.3 Figure 3 and Figure 4 show examples of a risk matrix and an example chart of IOW potential actions for operating conditions that exceed the established limits. For the risk assessment process, start by assuming a limit to a given parameter that may meet the premise established for the intended operating period. For that limit, determine how likely and how quickly the component or equipment might fail if that limit is exceeded. Also determine the consequences if failure does occur at the imposed limit level, i.e. small leak; large leak; immediate emergency; safety issue and size; environmental issue and size; reliability issue and size; etc. The product of these probability of failure and consequence of failure is the risk of failure. In Figure 4, some example guidance, actions, involvement, and responses to different levels of risk are shown.

6.4 For this first example, time to failure is used to indicate probability of failure, where a probability of “5” = highly likely to fail within hours to days. For consequence of failure a combination of safety and business interruption will be used where the consequence of “D” = Significant exposure risk to personnel and potential loss of profit. This gives a “5D” category on the matrix in Figure 3 with a corresponding “high” risk. From Figure 4, Critical Limits are required to be established with appropriate alarms where operators are required to take

urgent predetermined actions to return the process to normal operation. In addition, the appropriate SMEs are notified for this parameter exceedance along with the operations supervisor.

6.5 A second example involves an unexpected process change that results in a likely to fail within a few months corrosion situation, if something is not corrected. So, it's not urgent, but needs attention relatively soon. A probability of 4 is assigned. The consequence involves a big leak which would involve a possible environmental citation and business interruption, as well as undesirable media attention. A consequence of C is assigned, resulting in a 4C medium high risk on the matrix in Figure 3. From Figure 4, Critical or Standard IOWs would be established with predetermined actions for operations associated with the exceedance to be implemented within the predetermined time. Also, a notification to corrosion/materials specialist would likely be made to assess the situation and recommend further actions.

6.6 A third example involves a small increase in the pH of the feed stream, increasing the corrosion rates above those on which the inspection plan was established. The probability of 2 is assigned. The consequence involves a small leak above reportable quantity, so a consequence of B is assigned. From Figure 4 an IOW Informational limit is recommended. Action required by operations is to notify the unit inspector and/or designated SME for review and potential modification of the inspection plans.

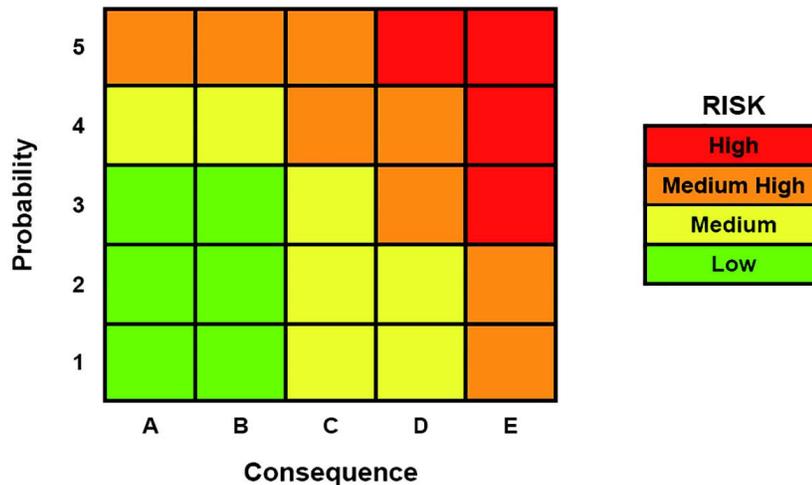


Figure 3—Generic Risk Matrix for Assessing IOW levels

Risk	Type of IOW	IOW Guidance/Action
High	Critical	IOWs Required - Limits and durations established on all IOW process parameters for monitoring; IOWs are alarmed/alerted, and SMEs are notified of exceedances; Operations take urgent predetermined action to return process to normal operation.
Medium High	Critical or Standard	IOWs Required - Limits and durations established on all IOW process parameters for monitoring; IOWs are alarmed/alerted, and SMEs are notified of exceedances; Operations take predetermined action to return process to normal operation.
Medium	Standard or Informational	IOW Informational limits Identified - IOWs identified suggested limits specified for each IOW; Operations and SMEs are alerted/notified of exceedances; Troubleshooting initiated with planned adjustments to operations, inspection/maintenance developed.
Low	Informational	IOW Informational limits suggested - Normal operating parameters identified for analysis; Parameters tracked and trended by SME to determine long-term effects on equipment reliability.

Figure 4—Example Risk Chart for IOW Types/Actions/Guidance

7 Examples of IOWs

7.1 An example of an IOW set for high temperature hydrogen attack (HTHA) is shown in Figure 5. Note that mechanical design limits from the construction code for the vessel are above the IOW limits for the process, which are typically set from the appropriate Nelson curve in API RP 941. Also, note that the start-of-run conditions (SOR) are within the IOW, but the end-of-run conditions (EOR) may be outside the IOW depending upon hydrogen partial pressure and the duration of the EOR conditions. In this case, some operator-users may decide that short-term operation at EOR conditions above the Nelson curve is acceptable based on the amount of time it takes for incipient HTHA to occur, i.e. no significant HTHA damage will occur. Other operator-user's may decide that the IOW should never be exceeded, even with short-term EOR conditions. Such decisions and determination of the required risk controls (e.g. the required frequency and extent of HTHA inspections) can be made using appropriate risk analysis and the input of knowledgeable corrosion/materials SMEs who are aware of the damage accumulation and incipient attack issues with HTHA.

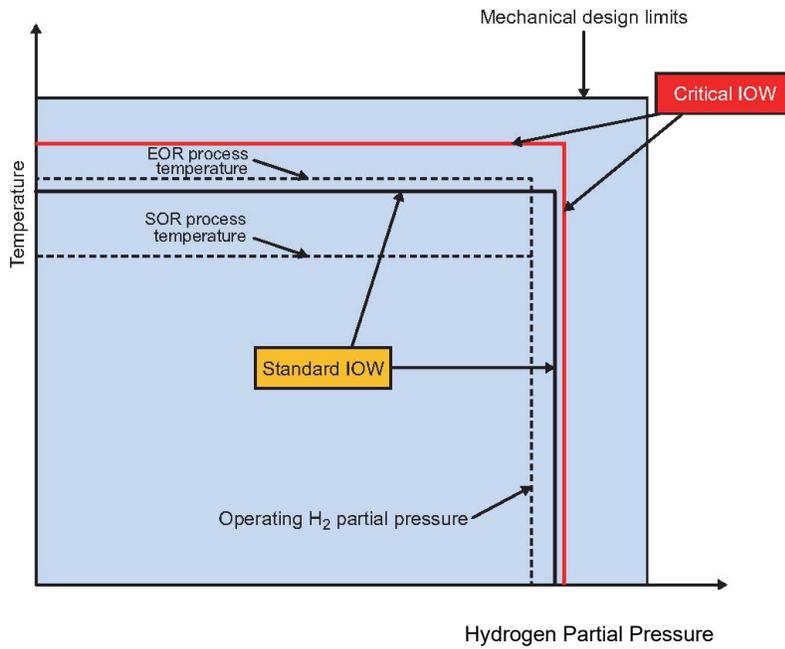
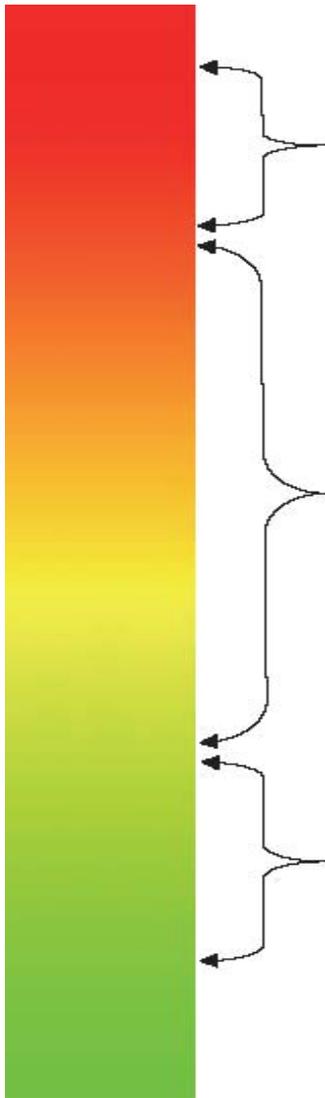


Figure 5—Example of IOW Limits for HTHA in a Hydroprocessing Unit

7.2 Figure 6 shows examples of different levels of IOWs (Informational, Standard and Critical IOW limits for controlling elevated temperatures on fired heater tubes.

Imminent Failure



IOW	Potential Issue	Example Response to Exceedances
Typical Range for <i>Critical</i> IOWs, Based on Short Term Failure	Short term overheating and stress rupture due to significant reduction in tensile strength	Alarm is set for the Board Operator who responds immediately with predetermined actions to gain control of the operation or shut down the fired heater
Typical Range for <i>Standard</i> IOWs, Based on Remaining Life Assessment	Temperature range for operation where some damage mechanisms may begin to shorten the equipment life, such as creep, sulfidation, oxidation, carburization, etc.	Alarms and/or Alerts are set for Operations which may or may not have a predetermined action and timing to implement. Regardless the situation may be reviewed with SMEs and a plan developed to bring the operation back into control and/or adjust the inspection plan and conduct remaining life calculations as appropriate
Typical Range for <i>Informational</i> IOWs Based on Design Life	Long term reliability of equipment up to the design life. Typically, the SME would be responsible for tracking and trending this information and adjusting the inspection and test plans, as necessary	The SME (e.g. Corrosion/Materials Specialist) is typically responsible for tracking the fired heater tube temperatures and recommending inspection and testing activities such as routine IR examinations, tube strapping, UT measurements, etc.

Figure 6—Examples of Different Levels of IOWs

7.2.1 Several high temperature damage mechanisms are possible in fired heater tubes. In general, long term creep and corrosion from a temperature dependent mechanism are the primary concerns. However, when operating at temperatures significantly higher than the design, failure by stress rupture can occur rapidly due to overpressure from the significant loss in material strength, i.e. short-term overheating and stress rupture. To establish IOW Standard and Critical temperature limits for new heater tubes, consider the following example;

- For a new fired heater designed to API 530, having 6" diameter low carbon steel radiant tubes (using minimum properties) with a nominal thickness of 0.28" and a 0.0625" corrosion allowance, and a 250 psig operating pressure. One approach would be to set a Standard limit at the 100,000-hour design temperature of 952°F (511°C) and a Critical limit set at the 20,000-hours temperature of 997°F (536.1°C). Exceeding the Standard limit would represent the potential to shorten the creep life below the typical 2 outage or shutdown periods impacting the longer term reliability of the heater, while exceeding the Critical limit based on 20,000-hours

(2.3 years) could potential produce a failure prior to the first outage or shutdown. When the Standard limit of 952°F is exceeded, operations personnel and subject matter experts (SMEs) should be notified and operators may be directed to adjust fired heater controls to get the tube temperature below 952°F within a pre-set amount of time. Operations exceeding the Critical higher temperature limit of 997°F, the operator might be directed to take more immediate actions to regain control or even shut down the fired heater. There may also be an Informational IOW limit at a temperature below 952°F where the operator does not have any action specified but appropriate SMEs would be notified that the tube temperatures are approaching their design limits. Such an Informational IOW allows the SMEs to begin planning for how to respond to increasing tube temperatures before it happens. As such there may be more than one IOW limit for the same process parameter (in this case fired heater tube temperature), for tracking/trending or to gain control prior to reaching a critical IOW limit. In addition, there may be more than one predefined response, depending upon the degree of exceedance of the process parameter limit.

7.2.1.1 Informational IOWs Inspection, Corrosion, and Process Engineering personnel (SMEs) would be responsible for tracking and trending fired heater tube temperatures operating below the design temperature, <950 °F (510 °C). A tube wall temperature upper limit may be set and/or notifications sent to inform the SME's if the temperatures exceed an upper limit of 900 °F (482 °C).

7.2.1.2 Standard IOW limit. The initial standard limit for fired heater tubes that operate in the creep range is frequently set at the API STD 530 design metal temperature (100,000-hour design life). This standard limit may be adjusted based on an engineering analysis from detailed knowledge of the time dependent damage mechanisms (creep and corrosion), and the estimated remaining life. For this example, the standard limit is set at 950 °F (510 °C). An alert (or an alarm) is used to notify SMEs and operations when this temperature is exceeded. Operators would be directed to adjust fired heater controls to get the tube temperature back to below 950 °F (510 °C) within a preset amount of time.

7.2.1.3 Critical IOW limit. The critical limit is set at a temperature prior to the point when failure is imminent due to significant reduction of strength with some amount of safety factor. For this example, a critical temperature limit of 997 °F (536.1 °C) was selected. An alarm point is set for the board operator that alarms when this temperature is exceeded, and the operator is directed to take immediate actions to regain control or shut down the fired heater to avoid failure.

7.2.1.4 This example shows how there may be more than one IOW limit for the same process parameter, for tracking/trending or to gain control prior to reaching a Critical IOW limit. In addition, there may be more than one predefined response, depending upon the degree of exceedance of the process parameter limit. In this example, all three levels of IOWs were set to show a progression of failure risk and communication and response initiating with the SMEs, then operations and ultimately the board operator to correct the increasing temperature.

7.3 The following are examples of where Critical IOW limits may be established.

- Delayed Coker heater pass flows because heater tubes could rupture quickly due to coking and overheating resulting from low flow.
- Boiler feed water level because loss of boiler feed water level could quickly cause boiler tube rupture. Hydroprocessing reactor temperature because metal temperatures below the minimum allowable temperature (MAT) could give rise to brittle fracture.
- Heater tube skin temperature because tubes could rupture quickly due to overheat caused by no flow or hot spot condition.

- Sulfuric acid strength in alkylation because low acid strength could cause a runaway reaction and increased corrosion.

7.4 The following are examples of where Standard IOW limits may be established.

- Calculated wash water vaporization rates for wash water effectiveness because full vaporization of wash water can result in fouling and increased corrosion.
- Calculated salt deposition temperature to avoid precipitation of salts and fouling because salt deposits can cause localized corrosion.
- Organic chlorides in purchased NHT feeds because organic chlorides can lead to very high corrosion rates in the NHT and other Hydroprocessing units.
- Hydrocracker reactor effluent air cooler (REAC) NH_4HS concentration because high NH_4HS content can contribute to increased corrosion of the air cooler and downstream piping.
- Heater tube skin temperature because high temperature could lead to eventual tube failure due to creep.
- Crude fractionator dew point temperature because sustained operation below dew point could result in subsequent damage to fractionator internals or potential loss of containment.
- pH of crude tower overhead because sustained operation below standard pH level could lead to corrosion of piping and heat exchanger components, especially tubing, and potential loss of containment.
- Water and/or chloride carry-over in hydrocarbon feed streams or hydrogen in Hydroprocessing units because chlorides could cause accelerated corrosion from ammonium salts and hydrogen chloride solutions.
- Crude desalter temperature because temperatures higher than 300 °F will cause permanent damage to the Polytetrafluoroethylene (PTFE) bushings that insulate the electric grids and deterioration of these bushings will cause grid shorting and rendering the desalter ineffective.
- Acid circulation rate in sulfuric acid alkylation deisobutanizer acid wash because high flow will increase acid entrainment due to over mixing and low rate will not allow for enough contact between acid and hydrocarbon.
- Iron content in fresh purchased acid to sulfuric acid alkylation units since fresh acid will dissolve iron to achieve saturation point. Low iron in fresh acid may increase corrosion.
- Delayed Coker feed TAN content because high total acid number (TAN) can cause corrosion in the temperature range of 425°F to 750°F.
- Delayed Coker feed sodium content because sodium will cause rapid fouling of the heaters and cause overheating of the tubes. Increased spalling due to rapid coking can cause return bend erosion/corrosion when coupled with higher flow rates.
- FCCU fractionator bottoms system solids content because solids coupled with a critical flow rate can result in rapid erosion/corrosion.

7.5 The following are examples of where Informational IOW limits may be established.

- Calculated heat transfer coefficients and pressure drops for heat exchangers because changes indicate fouling that may increase corrosion.
- pH, chlorides, hardness, iron, cyanides in wash water to avoid corrosion.
- Temperature differences between parallel banks or tubes from infrared surveys for flow distribution in reactor effluent air cooler (REAC) systems that could lead to accelerated corrosion.
- Process through-puts that exceed design and may affect damage mechanisms.
- Turbidity of cooling tower water because an increase can be an indication of increased risk of deposits and biological attack.
- Cyanide content in FCCU and DCU gas plant waters because the presence of cyanide will promote wet H₂S cracking and promote general corrosion by destroying the protective iron sulfide layer.
- Iron concentration (ppm) in the steam condensate system because increased iron indicates that corrosion is occurring in the condensate system. This could be an indication of upstream problems in either water treatment or neutralizing amine injection.
- Temperature that has increased because of process creep. The temperature may have increased to a point that it now puts the equipment in the sulfidation range.
- Temperature that has fallen into the external stress corrosion cracking range on an insulated stainless steel vessel.

7.6 Additional examples of IOWs are included in the Annexes of this RP:

- Annex A provides IOW examples of operating parameters for which sites may want to set limits for some generic process units..
- Annex B provides an example of a tabular recording of IOWs, including the IOW parameter, the related damage mechanisms, the required response, the timing of the response, related information and responsible party.
- Annex C provides an example IOW work process for a hypothetical heat exchanger.

8 IOW Development

8.1 ~~A documented work management system to create, implement and sustain the IOW program should be developed~~ When an IOW program is being established, a documented work management system to create, implement and sustain the IOW program shall be developed, and typically would include the following elements:

- composition of team members. See 8.2 below;
- roles, responsibilities, and qualifications for team members;

- required data and information to be reviewed;
- depth of design and operating analysis;
- integration with existing PSM and operational programs;
- how the IOWs are to be implemented;
- how the IOWs will be documented;
- handling of suggested monitoring instrumentation/controls and/or sampling points;
- the frequency of subsequent IOW reviews and to whom ownership of the procedure belongs;
- how IOW exceedances will be communicated and to whom; and
- required actions and follow up for exceedances, including operator actions and SME or inspector actions (e.g. modify inspection plans or investigation cause of exceedance)

8.2 In order to develop the necessary information, identify potential damage mechanisms and failure scenarios along with consideration for future operating conditions and business objectives, the combined efforts of a multidisciplinary team of SMEs shall be required. The make-up of the team and their roles are typically as follows.:

8.2.1 Site corrosion/materials specialist - Corrosion/materials specialists identify damage mechanisms for the IOW team. A corrosion/ materials specialist should also supply the systems or circuits/CMDs (where they are available), and estimated corrosion rates where measured rates for the current operating conditions are not available. They also have a role in understanding exceedances and advising inspection personnel on how inspection activities might need to be revised to account for the exceedance, if any, as well as advising process engineers on process issues that may need to be considered to avoid long term materials degradation issues. A corrosion/materials specialist will often have the role of facilitating the IOW team and documenting and distributing the results of the IOW work process. The corrosion/materials specialist may also have a role in providing operator training on IOWs.

8.2.2 Unit process engineer/technology specialists - The unit process engineer brings process design and engineering data to the IOW team. Often the unit process engineer is the designated “owner” of the IOW list and responsible to ensure that all IOWs are properly and continuously implemented in the manner designated in the IOW documentation. The owner of the IOW work process would also have the responsibility to ensure that exceedances were properly reported to others and a role in responding to exceedances and ensuring that responses to exceedances were handled and implemented in a timely manner. Process representatives should discuss if proposed IOWs would currently be in alarm for further technical discussion and review

8.2.3 Unit inspector - Inspection personnel bring inspection and MI data to the IOW team, as well as adjusting inspection activities/plans as necessary when IOW exceedances are reported to them.

8.2.4 Unit pressure equipment engineer - Mechanical and/or reliability engineers identify previous equipment failures, repairs and experiences.

8.2.5 Experienced unit operations representative(s) - Operations is responsible for monitoring and responding to any IOW exceedances in the manner designated in the IOW control system and documentation. In addition, they provide information to the IOW team about current operating practices and data. They will also provide information about the frequency of upset conditions. This would include

obtaining water and process samples which have been identified as IOW monitoring points. Additionally, operations have the responsibility to communicate any IOW exceedances in the designated manner to other designated stakeholders for their potential actions.

8.2.6 Process chemical treatment vendor (as needed, ad hoc) - The chemical treatment specialist should have knowledge of corrosion control treatments and results. They often take and test samples and can provide sample results to the team. They will often be aware of specific unit issues such as fouling that may be related to corrosion.

8.2.7 Facilitator knowledgeable in the IOW work process - The facilitator should elicit information about what is happening in the field relative to what is in the documented records or what is “thought to be happening” by those who are not operators. The facilitator needs to have the skill for asking the right probing questions to fully understand issues that may impact the IOW work process. A good working knowledge of industry failure frequencies is also desirable for the facilitator, or someone on the team.

Note: The IOW team facilitator is often an experienced corrosion/materials or mechanical integrity specialist, either from the plant, a central office, or a third party.

8.2.8 Consultants, contractors and third-party employees can be included in the team membership to assist with data gathering and to provide technical knowledge. However, successful development and implementation of IOWs requires continued involvement and participation by site and unit personnel. Site and unit knowledge are a key to success and generally consultants, contractors and third-party employees will not have enough knowledge of the site and of the specific unit operations. Work by consultants, contractors and third-party employees should be validated by site or unit personnel. See Annex D for potential issues with the IOW development and implementation process.

8.3 The qualifications of the team and the quality of the IOWs produced are dependent upon this team.

8.4 Considerable information is needed by the IOW team to develop each unit's specific set of IOWs. To facilitate the work process, this information should be provided to the team prior to their meeting to the extent possible. Otherwise, it should be collected and brought to the meeting. Similar information is needed for the CCD work process as outlined in API RP 970. The CCD and IOW work processes have common elements and can be worked together. The information for development of IOWs is similar to that needed for the Corrosion Control Document (CCD) work process as outlined in API RP 970. This information typically could include:

- process and reactive chemistry knowledge;
- process flow diagrams;
- P&ID's that show sample points, IOW monitoring instruments, etc.;
- piping isometric drawings that show all injection points, mix points, deadlegs and other piping hardware details that are included in the inspection program;
- existing operating windows and defined actions that are already in effect;
- identification of start-up lines, temporary use lines and normally closed valves;
- operating and maintenance procedures;
- process chemical treatment programs;

- feed sources, volumes, and compositions including intermediate products;
- knowledge of damage mechanisms, possible and probable that could occur in the process unit;
- historical operating, maintenance and inspection records for the process unit;
- failure analysis and lessons learned reports for the operating unit and/or similar operating units;
- equipment/process design data; laboratory data; operating data for the process unit (note the emphasis on data rather than “impressions” or SME judgment);
- start-up, shut-down, and unusual operating conditions;
- MOC records for the operating unit;
- data from existing sample points;
- existing process variable controls and measurement points e.g. pressure indicators (PI’s), temperature indicators (TI’s), analyzers, flow controllers (FC’s), etc.;
- metallurgical and corrosion information and data, (published and company private) related to the damage mechanisms anticipated for the process unit;
- materials of construction and materials engineering knowledge, including CMD’s;
- operating knowledge;
- applicable industry and company recommended practices and standards;
- process and corrosion modelling results;
- original unit feed composition.

8.5 Examples of unit specific process data that can be used during the IOW process include the following.

- *Crude units*—Historical crude assays, average sulfur composition for the raw feed and primary cuts or product streams, total acid numbers, fired heater monitoring data (IR and process temperatures), side-stream temperatures, overhead process parameters such as velocities, pH, chloride contents, crude salt content, desalter efficiency and reliability, caustic injection rate (and strength) into desalted crude etc.
- *Hydroprocessing Units*—Hydrogen, hydrogen sulfide and ammonia partial pressures, wash water volumes, injection points, and sources and quality of water, feed TAN and chloride content, etc.
- *Amine systems*—Type of amine, loading, filtration, overhead bleed/purge rates, chloride content, HSAS content, % water in amine, steam temperature of amine reboilers, flow velocity, etc.
- *Catalytic Crackers*—Polysulfide injection systems, slurry solid content, HCN and carbonate concentration in Gas Plant System, etc.
- *Claus Sulfur Units*—Acid gas feed temperature, temperature of cold wall thermal reactor, temperature of final condenser outlet temperature, acid gas loading, sulfur levels.

- *Sour Water Strippers*—Concentration of NH₃ in Circulating Reflux.
- *Mercox Units*—Sodium content of DSO, air controls.
- *Selective Hydrogenation Unit*—Di-Olefins content.
- *Sulfuric Acid Alkylation*—Spent acid strength to storage, acid strength, acid temperature, water content of acid, acid/hydrocarbon ratio in contactors, contactor Isobutane/Olefin ratio, acid precipitator amps & voltage, acid circulation rate to DIB feed acid wash, DIB acid wash mix valve pressure differential, caustic strength of Alky DIB caustic wash.
- *Hydrofluoric Acid Alkylation*—Water content in acid, isostripper and depropanizer temperatures, defluorinator breakthrough monitoring.
- *Catalytic Reformer*—Fired heater temperatures, HCl content of reformer recycle gas, H₂O content of recycle gas, HCl content of hydrogen exiting the hydrogen HCl scrubbers.
- *Delayed Coking Unit*—Sodium in feed, TAN, velocity in Coker heaters.

9 General Considerations for Establishing IOWs and Their Limits

9.1 Historical integrity and reliability problems as well as changes that are anticipated in the process unit should be considered in the IOW development.

9.2 There may be upper and lower limits that need to be established, and there may be one or more levels of those limits with different actions and different time frames required as each IOW level is exceeded. The IOW team should decide whether each IOW needs to have both upper and lower limits, and if standard and/or critical limits need to be established for each IOW. Not all IOWs will have critical limits, and many may have only an upper or a lower limit. Some Critical or Standard limits may warrant having IOW Informational limits established.

9.3 Actual operation sometimes deviates from design for various reasons. Those differences can cause accelerated or unanticipated degradation with undesirable consequences. Those deviations need to be considered.

9.4 There are numerous documented cases within the industry of accelerated corrosion and cracking under adverse conditions that range up to a few inches per year (see Table 1 for examples). The corrosion/materials specialist needs to be aware of this type of information to help the team decide what the appropriate response needs to be and how fast the actions need to be implemented.

9.5 Numerous issues can cause deviations between actual and design operating conditions, including fouling of exchangers in series, operating with exchanger by-passes open, process conditions creeping upward without notice, lack of understanding of the nature and consequences of unanticipated degradation, misunderstanding

Table 1—Examples of Accelerated Corrosion Rates That Can Occur Under Some Circumstances

Unit: Corrosion/Damage Mechanism	Documented Out-of-Control Corrosion Rates	Time to Failure
Crude Unit: HCl/Amine Chloride Corrosion in Ovhd and TPA	>2,000 mpy	Failed a new exchanger bundle in 18 days.
Reformer: HCl/Ammonium Chloride	>3,500 mpy	New alloy finfan exchanger failure in 3 months, related to over injection of PERC and low operating temperatures.

Catacarb Unit: Wet CO ₂	>5,000 mpy	Failure can occur in days to weeks on the piping at a dew point.
FCC Unit: Erosion of slurry system piping	>1,000 mpy	Multiple failures in slurry pumps and piping within 6 weeks after suspected cyclone failure.
Alkylation: H ₂ SO ₄ /Acid Esters	>15,000 mpy	Failure occurred in 11 days on a new pipe reducing elbow where H ₂ SO ₄ was diluted with H ₂ O + Cl.
HDS; HCl/Ammonium Chloride	>300 mpy	Failure occurred at a piping mix point combining H ₂ +Cl and wet HDS H ₂ in approximately 2 years.

between construction code design conditions and material of construction design limits for specific types of degradation, and not recognizing the impact of end-of-run (EOR) conditions versus normal or start-of-run (SOR) conditions.

9.5.1 For example, if there are banks of heat exchangers in series in high temperature, high pressure hydroprocessing service, designers sometimes assume operating conditions over the life of the plant based on the maximum expected degree of fouling. However, if the inlet exchanger in the series fouls more than expected and no longer cools the stream sufficiently, the next exchanger(s) in the series might see higher temperatures than design, in which case it might become susceptible to HTHA or sulfidation. Another situation occurs when process conditions begin to creep upward or downward over time; also known as “process creep”. This might entail scenarios such as periodic, but small increases in temperature, small increases in hydrogen sulfide content, increases in unit throughput or increases in hydrogen partial pressure. Another example of process creep is the incremental unit through-put over time that eventually exceeds design conditions and can result in accelerated erosion-corrosion. If those changes are not noticed, or not put through a management of change process, or if the proper IOWs are not in place, then unanticipated and, therefore, undetected materials degradation could occur.

If for process reasons operators open a by-pass around an upstream exchanger causing hotter material to enter downstream equipment that was not designed for those hotter conditions, then unanticipated and undetected materials degradation such as HTHA or sulfidation could occur.

9.5.2 A very specific set of operating instructions may be needed to address situations such as shock chilling or auto-refrigeration where preventing potential brittle fracture will be the primary concern of operations. In such cases, it may not be appropriate to simply return the process to normal operating conditions e.g. repressuring, without due attention to the potential for avoiding brittle fracture.

9.5.3 In some hydroprocessing equipment, EOR conditions (e.g. temperature and hydrogen partial pressure) are more severe than SOR or normal operating conditions. If EOR operating conditions are severe and/or last much longer than original design or normal operating conditions, then that could result in exceeding the HTHA resistance of the materials of construction.

9.6 The number of IOWs for each process unit will depend on the:

- number and extent of damage mechanisms anticipated and likely to be present;
- risks associated with the process fluids;
- complexity of the process unit;
- extent of corrosion resistant materials of construction.

9.7 There is not a target number of IOWs for a typical process unit. A key to success is that the IOWs be comprehensive, effective and pragmatic, and this requires the participation of experienced and knowledgeable SMEs and Operations personnel.

9.8 The result of analyzing all this information and the team deliberations is typically a set of reasonable, practical IOWs that are not too conservative but not non-conservative, both extremes of which are not desirable and need to be avoided. Non-conservative IOWs could lead to more degradation than desirable or anticipated and therefore higher risk; whereas IOWs that are too conservative could lead to a waste of valuable resources and lost opportunity. For example, establishing a fired heater tube-skin temperature limit that is too high may not allow the operator enough time to adjust firing conditions before tube damage occurs; whereas, setting a tube-skin temperature too low may lead to limiting fired heater operating conditions [and therefore lost profit opportunity (LPO)], where it is unnecessary to do so from a materials engineering standpoint.

9.9 Only a small percentage of IOWs e.g. five to ten percent of the total may end up being designated by the team as “Critical Limits” i.e. where the operator will need to take immediate/rapid action to control the process or shut down. Some sites merge their Critical IOW limits with their Safety Operating limits (SOLs). Most of the remaining IOWs will typically be designated as “Standard Limits” i.e. where the operator needs to act within a specified timeframe to get the process back within the IOW limits to avoid escalation of the issue to a critical limit. A smaller subset may be designated as IOW Informational limits i.e. where SMEs will need to be notified for potential follow up actions.

9.10 Exceedances of Critical IOW limits may have more formal communications and follow up requirements and more extensive reporting to stakeholders and be treated similar to an incident investigation, whereas, Standard and Informational IOW exceedances may require reporting only to technical and inspection personnel for follow up and investigation. If systems are available, automated communication of IOW exceedances from on-line control and information systems directly to designated stakeholders can improve the effectiveness and efficiency of the IOW communication process.

10 Documenting, Implementing, and Training on Established IOWs

10.1 There are multiple methodologies that can be used to document each set of IOWs. ~~The variations depend on the specific methodology adopted by the end user, which shall be documented.~~ For this RP, two examples are provided below: a "concise" methodology versus a "detailed" methodology.

10.1.1 *A Concise Method*—Simply compile a list of IOWs for each process unit and include in the standard operating procedures, including:

- the specific limits established,
- the recommended operator intervention/control steps,
- the timeliness of each intervention/control action, and
- required IOW exceedance communications

10.1.2 *A Detailed Method*—Include the IOWs as part of a comprehensive document on corrosion control in every process unit and add the IOWs and response requirements to standard operating procedures. These documents have been called corrosion control documents (CCDs), corrosion control manuals (CCMs), or risk-based inspection (RBI) data files by some in the industry. The Corrosion Control Document (CCD) is described in API RP 970.

These documents may include but are not limited to the following.

- Description of the process unit and the normal process conditions.
- Shutdown, start up, and abnormal operating conditions that may affect corrosion and other damage mechanisms, including the possibility of inadvertent contamination of process streams with unexpected but possibly predictable corrosive species.
- Process flow diagrams (PFDs) showing all construction materials.
- Systems or circuits which are areas of similar corrosion mechanisms, similar operating conditions, and similar materials of construction in each portion of the unit.
- Probable damage mechanisms in each corrosion circuit, where each damage mechanism is expected to occur, the relative susceptibility to the damage mechanisms, as well as likely damage rates expected to occur and under what circumstances.
- A history of corrosion problems that have been experienced in this process unit or similar units.
- Quantitative and predictive models for the damage mechanisms.
- Corrosion control procedures and practices such as those dealing with chemical injection, inhibitors, water washing, neutralizers etc.
- Recommended types of inspections focused on specific damage mechanisms, corrosion monitoring, process parameter monitoring process changes, construction materials, etc., basis for each IOW, including any assumptions made.
- Risk analysis performed to prioritize the various IOWs and their associated monitoring methods, and of course.
- The applicable IOWs that include the information in the simpler format above for recording IOWs. The more detailed documentation methods can become a resource for the following:
 - The entire corrosion and damage management strategy for the process unit.
 - The implementation effort for all IOWs that will be input into the process monitoring and control system.
 - Training and reference material for operators, engineers, inspectors and others that need to know the background for why each IOW was established, especially when considering possible changes.
 - Risk-based inspection planning.
 - Management of change decision-making that may affect equipment integrity, and process hazards analysis (PHA) discussions.

10.2 Various combinations of the above two documentation methods can be developed depending upon the needs and desires of the operator-user.

10.3 Effective implementation of the IOW list is equally as important as establishing IOWs, so that effective actions within a specified timeframe are taken each time an exceedance occurs. Prior to starting an IOW program, plant management should assure that a plan and process exist for the implementation of the IOWs. The process for implementing IOWs should be integrated with that for other operating variables. IOWs requiring

operator actions should be included in standard operating procedures. A comprehensive list of IOWs should be readily available and communicated to responsible personnel, which could typically include:

- operations personnel,
- operations supervision/management,
- business/oil movements,
- inspection personnel,
- process engineers,
- reliability engineers,
- corrosion/materials specialists,
- safety/PSM/environmental personnel.

10.4 Like all operating envelopes, an important part of IOW implementation is training. Once IOWs are established, unit personnel need to become knowledgeable about all the unit-specific IOWs in their operating area, and especially knowledgeable in the reasoning behind them, so they can understand why it's important to take the predetermined action within the specified timeframe. They also need to understand the undesirable consequences of failing to act within the specified time frame. This operator training should include such things as:

- why the IOW was established, i.e. its purpose and intent;
- what damage mechanism is being prevented or controlled by the limits established;
- a clear understanding of the difference between Informational, Standard and Critical limits, as well as the reason for the different response actions and timing;
- if there are multiple levels of the IOWs, i.e. upper and lower, as well as multiple levels of responses and response timeliness, then the reasons for each level of response needs to be fully understood;
- what can happen in the process unit, both short and long term, if the established responses are not implemented in a timely fashion when limits are exceeded;
- the desired exceedance communications, by what mechanism and with whom to communicate, if an IOW limit is exceeded.

10.5 Training should include describing the difference between mechanical and process design conditions. Those involved in MOC assessments for changes in the process design conditions should understand the materials selection design conditions. There sometimes is a misunderstanding regarding the differences between the design conditions stamped on the nameplate of the equipment and the actual process operating limits of the equipment based on damage mechanisms. The mechanical design limits for pressure and temperature per ASME Code construction stamped on the vessel may be much higher than the operating limits established for materials of construction degradation resistance. This difference is one of the many reasons that IOWs are beneficial.

11 Monitoring and Measuring IOW Parameters

11.1 Additional monitoring and control instruments, and/or sampling points for some IOW variables may be required. To monitor and measure the IOW parameters, control systems and procedures are necessary to store the IOW data and notify the operator when an exceedance has occurred. If it's a monitoring instrument, then instrumented displays and some alarms will likely be needed. If it's a sample point, then procedures and practices will be needed to analyze a designated process stream and report it back to the operator within a predetermined amount of time so that the appropriate actions can be taken in the event of an IOW exceedance. Some systems generate trending data for IOWs and automatic electronic notifications to a predetermined list of stakeholders.

11.2 The overall response time of the system needs to be considered when setting alarm and "notification" limits/levels. The response time needs to account for not only the limitations on the instrument/detector response but also the overall design and limits of the communication system (getting the message to the intended audience). System response time is the length of time from when a limit has been violated until the mitigation procedure is activated. This time will be a function of system deployment, device response time, and activation strategy. System response time should be scaled relative to the risk level for Critical and Standard IOWs. The physical characteristics of the instrument and detection system also need to be considered. It is important to note that device response time may be significantly affected by ambient conditions. See API RP 556, for practices on control overrides, alarms, and protective functions for fired heaters.

11.3 In most cases, alarms will accompany Critical IOWs and some Standard IOWs, depending upon necessary timing of IOW response. Process safety management may need to review the number of alarms to avoid "alarm flood" in the event of an emergency. Operating companies should refer to their existing alarm management and rationalization strategies, ~~typically following guidance given in ANSI/ISA 18.2 and ISA 84.00.01~~. Notifications to specified stakeholders/SMEs should accompany critical and selected/specified standard and informational IOWs.

11.4 Appropriate monitoring equipment should be installed at strategic locations to provide the information necessary to determine if an IOW exceedance may be occurring. As a part of the IOW implementation process, requirements for new sample stations, instruments and analyzers should be identified. Capital investment for monitoring and sampling systems may be needed. Risk analysis and risk ranking are useful for prioritizing those investments and comparing them to other capital and expense needs of the plant.

11.5 Monitoring at sample points may be implemented as an interim application where data is needed to understand the process parameter and to refine the required frequency of measurement or sampling to evaluate the need for installation of future control or measurement instrumentation.

11.6 For some IOW Informational Limits, several types of corrosion monitoring methods may be used, including: corrosion coupons, corrosion and hydrogen probes, and infrared thermography.

12 Updating IOWs

12.1 Periodic team meetings between Operations and SMEs may be useful to monitor the status and update the IOW list, i.e. reassessment of the IOW list. This should include a periodic review and update of the potential damage mechanisms. The damage mechanism review may be integrated with the periodic review of an RBI analysis, where it has been implemented.

12.2 The IOW list should be updated as needed to account for process and hardware changes (recent and planned), exceedance feedback, inspection results, new information about damage mechanisms, or a variable or damage mechanism identified after the original IOW list was established. Additionally, updates to or addition

of IOWs should be evaluated as part of incident investigations following unexpected loss of containment, surprise inspection findings or leaks. API RP 585 is useful guidance for conducting investigations of pressure equipment leaks and near leaks.

12.3 The MOC process shall be applied whenever Critical or Standard IOW variables are being revised or updated, utilizing the same types of experienced SMEs that were used to generate the original IOW list. A modified, streamlined MOC process specifically addressing IOW updates could be developed by operator-users.

13 Roles, Responsibilities, and Accountabilities for IOWs

13.1 Personnel at the plant site, in addition to the team members in 8.2, needed to support the IOW team include:

- plant management,
- process safety management,
- laboratory, and
- control systems,

13.2 Plant management has the accountability of ensuring that the IOW work process is adequately staffed with the appropriate experienced SMEs; that realistic schedules are developed for establishing and implementing IOWs; that IOWs agreed upon are implemented; that adequate resources for monitoring and sampling are allocated, and that control systems are designed, purchased, installed, and implemented. Plant management should assign a site or unit individual to be responsible for the IOW development and implementation process and should not delegate ownership to external consultants, contractors or third-party employees. Plant management also has the responsibility to audit the IOW work process to ensure that it is operating in accordance with specification, and to assure IOWs are fully implemented. Operations management has the responsibility to ensure that all unit operators are adequately trained on IOWs and their required responses to exceedances.

13.3 PSM personnel should ensure that the IOW work process is adequate to meet the process safety information (PSI) aspect of local and federal regulations and that the MOC process is properly utilized for making changes to the IOW list.

13.4 Laboratory personnel are responsible for implementing, recording and reporting required sample analyses used for IOW monitoring.

13.5 Control systems personnel are responsible for designing, purchasing, installing and maintaining control and monitoring systems for IOWs.

14 Integrating IOWs with Other Related Work Processes

14.1 The IOW work process should be closely integrated with pressure equipment integrity work processes (inspection, corrosion management and maintenance) at the plant site. As indicated in the introduction, the pressure equipment integrity work process can only be adequately accomplished when both pressure equipment integrity and IOW work processes are performing effectively with close interaction between the two.

14.2 The IOW list and documentation should be a resource for PHA. Critical IOW limit exceedances should be reviewed by the PHA team (or as pre-work by the IOW team) to determine if actions or limits may need to be revised.

14.3 The IOW work process and documentation should be a resource for the RBI work process, since both require the same level of analysis of potential damage mechanisms. In fact, an IOW workshop and RBI workshop could be combined where there is complete overlap in resources and timing of the two programs. The analysis of IOW exceedances may affect the inspection plans generated by RBI, or other modes of inspection planning, including time-based and condition-based inspection plans. The information assembled to produce the more detailed IOW documentation mentioned in 10.4 can become part of the front-end data input to the RBI process, which would in turn produce a detailed risk-based inspection plan for each piece of fixed equipment including: inspection scope, methods, techniques, coverage, frequency, etc. Refer to API RP 580 and RP 581 for additional guidance on the RBI work process.

14.4 As indicated in sections 1.3, 5.7, 8.4, 10.5, 12.3 and 13.7 the MOC work process should be closely integrated with the IOW work process for any changes, additions or deletions to be made to the IOW list.

14.5 The IOW work process should indicate how new IOWs will be integrated with existing SOLs, ROLs, OEs and other limits.

Annex A

(informative)

Examples of Potential Process Parameters for IOWs for Generic Process Units

The following process unit IOW tables are provided as examples of typical IOWs and expected damage mechanisms. These tables are intended to be used as guidelines or starting points for conducting an IOW review. Many operator-users have developed similar spreadsheets to document IOWs. The tables in this annex do not include all information typically included in an IOW template. Other information typically tracked as part of the IOW process include:

- List of the recommended IOWs
- Recommended test or sample location for the IOW, along with PI tag numbers where available
- Recommended limits (Max/Min/Target) for the IOW
- Recommended sampling frequency
- Recommended API RP 584 IOW type (Informational/Standard/Critical)
- Possible consequences of IOW exceedances/deviations
- Corrosion loop or loops impacted by the IOW
- Recommended Operations/Process responses to IOW deviations
- Recommended Inspection/SME responses to IOW deviations

Annex B includes a sample format for recording process unit IOWs.

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Refinery Units

Table A1 Example IOWs for Crude Distillation Unit (Atmospheric and Vacuum Distillation)

Table A2 Example IOWs for Catalytic Reformer Unit

Table A3 Example IOWs for Hydroprocessing Unit

Table A4 Example IOWs for FCC Unit and Gas Plant

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Table A7 Example IOWs for Delayed Coker Unit

Table A8 Example IOWs for Steam Methane Reformer (Hydrogen Manufacturing) Unit

Table A9 Example IOWs for Amine Unit

Table A10 Example IOWs for Sour Water Stripper Unit

Table A11 Example IOWs for Sulfur Recovery Unit

Petrochemical Units

Table A12 Example IOWs for Ethane Cracking Units

Utilities

Table A13 Example IOWs for Boiler Water Treatment and Return Condensate Quality

Equipment Specific

Table A14 Example IOWs for Fired Heaters

Note: The IOWs established for a given unit may be fewer or more in number than the example IOWs in these tables, and will depend on the feeds processed, the metallurgy in the unit, the unit's inspection/damage history and near term revamps, process changes, etc. that are planned. An IOW team made up of experienced, pragmatic SMEs is needed for effective IOW development. It is not the intent of these tables to list all required IOWs, nor is it the intent that all of the listed IOWs be necessary. The tables are intended as guidelines for consideration.

Table A1 Example IOWs for Crude Distillation Unit (Atmospheric and Vacuum Distillation)

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Crude S	Total crude feed to unit	Wt. % S	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Crude TAN	Total crude feed to unit	mg KOH/ ml crude	Naphthenic acid corrosion	API RP 571 API RP 581
Crude salt content	Total crude feed to unit	ppm or ptb	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109
Hydrolysable salt content out of the desalter	Desalter outlet	ppm or ptb	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109
BS&W in crude	Desalter outlet	Wt. %	Preheat train fouling	
Desalter wash water rate	Desalter water injection	flow rate	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109
Desalter water mix valve pressure drop	Desalter water mix valves	Delta pressure	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Desalter temperature	Desalters	Temperature	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	
Desalter chemical rates	Desalter	Injection rates/ dosage	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	
Desalting water quality: pH, NH3 and dissolved O	Desalting water make-up	pH ppm NH3 ppb O	HCl corrosion Ammonium chloride corrosion Amine salt corrosion Crude tower overhead acids	NACE Publication 34109
Caustic injection	Desalted crude after caustic injection	Flow rate	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	
Organic chlorides in the unit feed	Crude receiving	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
Heater tube skin TIs	Crude heater radiant tubes	Temperature	Stress rupture Creep Sulfidation corrosion	API STD 530 API 579-1/ASME FFS-1 API RP 939C
Heater coil outlet temperature	Crude heater outlet	Temperature	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Heater coil pressure drop	Crude heater inlet and outlet	Pressure drop	Stress rupture or creep due to fouling	

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Transfer line velocity	Crude heater outlet to crude tower	Flow velocity	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Inlet and outlet temperatures in feed preheat exchangers	Preheat exchangers/ tube and shell side	Temperature	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Side cut total S content	Crude tower side cuts	Wt. % S	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Side cut TAN	Crude Tower side cuts	mg KOH/ ml sample	Naphthenic acid corrosion	API RP 571 API RP 581
Side cut temperatures	Crude Tower side cuts	Temperature	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Margin above dewpoint	Crude tower top	Temperature difference from calculated dew point	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109
Margin above salt point	Crude tower top	Temperature difference from calculated salt point	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109
Overhead velocity	Crude tower top to condenser inlets	Flow velocity	Flow accelerated corrosion	NACE Publication 34109
pH of overhead water	Crude tower overhead accumulator	pH	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Chloride in overhead water	Crude tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109
Overhead wash water rate	Water injection location into crude tower overhead line	Flow rate	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
Neutralizer injection rate	Injection location into crude tower overhead line	Flow rate	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
Filming inhibitor injection rate	Injection location into crude tower overhead line	Flow rate	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
Iron in overhead water	Crude tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
Ammonia in overhead water	Crude tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion Ammonia stress corrosion cracking	API RP 571 NACE Publication 34109
Sulfates in overhead water	Crude tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Tramp amines in overhead water	Crude tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
H2S in overhead water	Crude tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion Sour water corrosion (acidic) Wet H2S damage	API RP 571 NACE Publication 34109
Tramp amines in naphtha	Naphtha from overhead	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
Tramp amines in kerosene	Kerosene cut	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
Vacuum Unit Feed S	Atmospheric residuum/ combined feeds to vacuum unit	Wt. % S	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Vacuum Unit Feed TAN	Atmospheric residuum/ combined feeds to vacuum unit	mg KOH/ ml crude	Naphthenic acid corrosion	API RP 571 API RP 581
Heater tube skin TIs	Vacuum heater radiant tubes	Temperature	Stress rupture Creep Sulfidation corrosion	API STD 530 API 579-1/ASME FFS-1 API RP 939C

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Heater coil outlet temperature	Vacuum heater outlet	Temperature	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Transfer line velocity	Vacuum heater outlet to vacuum tower	Flow velocity	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Side cut total S content	Vacuum tower side cuts	Wt. % S	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Side cut TAN	Vacuum tower side cuts	mg KOH/ ml sample	Naphthenic acid corrosion	API RP 571 API RP 581
Side cut temperatures	Vacuum tower side cuts	Temperature	Sulfidation corrosion Naphthenic acid corrosion	API RP 939C API RP 571 API RP 581
Margin above salt point	Vacuum tower top	Temperature difference from calculated salt point	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109
pH of overhead water	Vacuum tower overhead accumulator/dip legs	pH	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109
Chloride in overhead water	Vacuum tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	API RP 571 NACE Publication 34109

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Neutralizer injection rate	Injection location into Vacuum tower overhead line/ ejectors	Flow rate	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
Iron in overhead water	Vacuum tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
Ammonia in overhead water	Vacuum tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion Ammonia stress corrosion cracking	API RP 571 NACE Publication 34109
Sulfates in overhead water	Vacuum tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion	NACE Publication 34109
H ₂ S in overhead water	Vacuum tower overhead accumulator	ppm	HCl corrosion Ammonium chloride corrosion Amine salt corrosion Sour water corrosion (acidic) Wet H ₂ S damage	API RP 571 NACE Publication 34109
Oxygen ingress to vacuum overhead system	Oxygen analyzer	Mol %	Sour water corrosion (acidic)	API RP 571 NACE Publication 34109

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Inhibitor injection rates	Crude/ Vacuum Unit naphthenic acid inhibitor injections (if used)	Flow rate	Naphthenic acid corrosion	API RP 571 API RP 581

Table A2 Example IOWs for Catalytic Reformer Unit

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Feed S	Feed to unit	ppm	Metal dusting	API RP 571
Feed N	Feed to unit	ppm	Ammonium chloride corrosion	
Recycle gas moisture content	Recycle gas sample	ppm	Ammonium chloride corrosion HCl corrosion	
Feed heaters tube metal temperatures	Feed heater tube skin TIs	Temperature	Short term overheat/ stress rupture Creep/ Stress rupture Metal dusting Carburization	API STD 530 API RP 571 API 579-1/ASME FFS-1
Feed heater minimum pass flow rate	Pass flow indicators	Flow rate	Short term overheat/ stress rupture Creep/ Stress rupture Carburization	
Inlet and Outlet temperatures of exchangers in feed and effluent services	Inlet and outlet TIs	Temperature	HTHA	API RP 941
Reactor MPTs	Reactor skin TIs	Temperature/ Pressure limits	Brittle fracture	API 579-1/ASME FFS-1
Debutanizer or stabilizer overhead water	Overhead accumulator	Water present - yes or no	Ammonium chloride corrosion HCl corrosion	
Catalyst regeneration system IOWs (dependent on type of unit - semi-regenerative, cyclic or CCR)	Unit specific		Ammonium chloride corrosion HCl corrosion Erosion	Process licensor

Table A3 Example IOWs for Hydroprocessing Unit

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Feed TAN	Combined unit feed	mg KOH/ g oil sample	Naphthenic acid corrosion	API RP 571 API RP 581
Feed N	Combined unit feed	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion	API RP 932B
Feed S	Combined unit feed	Wt. %	Ammonium bisulfide corrosion H ₂ /H ₂ S corrosion Sulfidation corrosion Wet H ₂ S damage	API RP 932B
Feed Cl-	Combined unit feed	ppm	Ammonium chloride corrosion HCl corrosion Chloride SCC	API RP 932B
Feed F-	Combined unit feed	ppm	Salting corrosion	
Feed water content	Feed out of coalescer	ppm	Ammonium chloride corrosion Chloride SCC	API RP 932B
Make-up hydrogen chloride	Make-up hydrogen to unit	ppm	Ammonium chloride corrosion HCl corrosion Chloride SCC	API RP 932B
Heat exchanger inlet and outlet temperatures	Inlet and outlet streams to exchangers in reactor feed and effluent (after H ₂ injection)	Temperature	HTHA H ₂ /H ₂ S corrosion Sulfidation corrosion	API RP 571 API RP 581 API RP 939C API RP 941

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Heater tube skin temperature	Feed heater tubes TIs	Temperature	Stress rupture Creep H2/H2S corrosion Polythionic acid SCC	API STD 530 API 579-1/ASME FFS-1 API RP 581 API RP 939C NACE SP0170
Heater minimum pass flow rates	Feed heater pass flow indicators	Flow rate	Short-term overheating - Stress rupture Creep	API STD 530 API 579-1/ASME FFS-1
Reactor MPT	Reactor skin TIs Reactor inlet pressure (start-up and shutdown)	Combination of pressure and temperature	Brittle fracture Hydrogen embrittlement	API RP 571 API 579-1/ASME FFS-1 API RP 934F (not yet published)
Reactor skin temperature	Reactor skin TIs in operation	Temperature	Creep/ Stress rupture Short-term overheating - Stress rupture HTHA	API 579-1/ASME FFS-1 API RP 941
Reactor bed temperature	Bed TIs	Temperature	Creep/ Stress rupture Short-term overheating - Stress rupture HTHA	
Wash water injection rate	Upstream of effluent air cooler	Flow rate	Ammonium bisulfide corrosion Ammonium chloride corrosion	API RP 932B
Unvaporized wash water	Wash water injection location/ Upstream of effluent air cooler	Calculated Vol % of wash water that does not vaporize	Ammonium bisulfide corrosion	API RP 932B

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
			Ammonium chloride corrosion	
Separator water NH ₄ S content	Sour water from cold separator	Wt. %	Ammonium bisulfide corrosion	API RP 932B
Separator water pH	Sour water from cold separator	pH	Ammonium chloride corrosion Sour water corrosion (acidic)	API RP 932B
Separator water chloride content	Sour water from cold separator	ppm	Ammonium chloride corrosion	API RP 932B
Wash water O content	Combined injection water	ppb	Ammonium bisulfide corrosion	API RP 932B
Wash water pH	Combined injection water	pH	Sour water corrosion (acidic) S precipitation - fouling	API RP 932B
Wash water total hardness	Combined injection water	ppmw as Ca hardness	Fouling - under deposit corrosion Injection system plugging	API RP 932B
Wash water dissolved iron	Combined injection water	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion	API RP 932B
Wash water chlorides	Combined injection water	ppm	Ammonium chloride corrosion	API RP 932B
Wash water NH ₃	Combined injection water	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion	API RP 932B
Wash water H ₂ S	Combined injection water	ppm	Ammonium bisulfide corrosion	API RP 932B

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Wash water free cyanide	Combined injection water	ppm	Ammonium bisulfide corrosion	API RP 932B
Wash water Total Suspended Solids (TSS)	Combined injection water	ppm	Fouling - under deposit corrosion Injection system plugging	API RP 932B
Effluent stream velocity	Effluent after water injection	Flow velocity	Ammonium bisulfide corrosion	API RP 932B
Sour water velocity	Sour water from cold separator	Flow velocity	Ammonium bisulfide corrosion	API RP 932B
Recycle gas H ₂ S	Recycle gas to injection	Mol %	H ₂ /H ₂ S corrosion Wet H ₂ S damage	API RP 939C API RP 571 API RP 581
Water carryover in fractionator feed	Feed from separators	ppm	Ammonium chloride corrosion Chloride SCC	
Fractionator feed S/H ₂ S	Feed from separators	Wt. %/ ppm	Sulfidation corrosion Wet H ₂ S damage	API RP 571 API RP 581 API RP 939C
Fractionator overhead inhibitor and carryover injection	Injection into fractionator overhead	Flow rates	Ammonium bisulfide corrosion Ammonium chloride corrosion Sour water corrosion (acidic)	
Fractionator overhead water NH ₄ HS content	Sour water from overhead drum	Wt. %	Ammonium bisulfide corrosion	
Fractionator overhead water pH	Sour water from overhead drum	pH	Ammonium chloride corrosion	API RP 571

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
			Sour water corrosion (acidic)	
Fractionator overhead water chloride content	Sour water from overhead drum	ppm	Ammonium chloride corrosion	
Fractionator overhead water iron content	Sour water from overhead drum	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion Sour water corrosion (acidic)	
Fractionator overhead water H2S content	Sour water from overhead drum	ppm	Wet H2S damage	API RP 571 API RP 581
Fractionator overhead water injection	Injection into fractionator overhead	Flow rate	Ammonium bisulfide corrosion Ammonium chloride corrosion Sour water corrosion (acidic)	
Heater tube skin temperature	Fractionator reboiler heater	Temperature	Stress rupture Creep H2/H2S corrosion Sulfidation corrosion	API STD 530 API 579-1/ASME FFS-1 API RP 581 API RP 939C
Heater outlet temperature	Fractionator reboiler heater outlet return to fractionator	Temperature	H2/H2S corrosion Sulfidation corrosion	API RP 939C
Fractionator side cut temperatures	Fractionator side cuts at tower outlets	Temperature	H2/H2S corrosion Sulfidation corrosion	API RP 939C

Table A4 Example IOWs for FCC Unit and Gas Plant

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Catalyst hopper temperature	Catalyst hopper TIs	Temperature	Dew point corrosion	
Expansion joint temperature	Catalyst circulation and flue gas expansion joints	Temperature	Embrittlement Dew point corrosion Sensitization - polythionic acid SCC	API RP 571 NACE SP0170
Feed S content	Feed to unit	Wt. % S	Sulfidation Sour water corrosion in fractionator overhead Wet H ₂ S damage in fractionator overhead	API RP 571 API RP 581 API RP 939C
Feed TAN	Feed to unit	Mg KOH/ g sample	Naphthenic acid corrosion (feed system)	API RP 571 API RP 581
Feed S/N ratio	Feed to unit	Ratio	Carbonate cracking (fractionation section)	NACE Publication 34108
Feed temperature	Feed system	Temperature	Sulfidation Naphthenic acid corrosion	API RP 571 API RP 581 API RP 939C
Metal temperature of refractory lined piping and equipment	Reactor, regenerator, circulation lines, flue gas ducting	Temperature	Short term overheat/ stress rupture Creep Graphitization Erosion	API RP 571
Volumetric flow for cyclone underflow				

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Fractionator side-cut temperatures	Fractionator side-cut TIs	Temperature	Sulfidation	API RP 571 API RP 581 API RP 939C
Fractionator side-cut S contents	Fractionator side-cut samples	Wt. % S	Sulfidation	API RP 571 API RP 581 API RP 939C
Solids in fractionator slurry	Slurry samples	Wt. % solids	Erosion	
Slurry temperature	Slurry TIs	Temperature	Sulfidation	API RP 571 API RP 581 API RP 939C
Slurry S content	Slurry samples	Wt. % S	Sulfidation	API RP 571 API RP 581 API RP 939C
Slurry flow velocity	Slurry flow indicators	Flow velocity	Erosion	
Slurry pump suction strainer delta pressure	Slurry pump suction strainer PIs	Pressure drop	Erosion	
Fractionator top temperature salting margin	Fractionator top TIs	Temperature margin between top temperature and sublimation temperatures for NH ₄ HS and NH ₄ Cl	Fouling Under deposit corrosion Ammonium bisulfide corrosion Ammonium chloride corrosion	API RP 571 API RP 581
Fractionator overhead water wash rate	Wash water flow indicator	Flow rate	Ammonium bisulfide corrosion Ammonium chloride corrosion	

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Fractionator overhead polysulfide injection rate	Polysulfide flow indication	Flow rate	Ammonium bisulfide corrosion Wet H2S damage	
Fractionator overhead accumulator water pH	Sour water from overhead accumulator boot	pH	Ammonium bisulfide corrosion Ammonium chloride corrosion Carbonate cracking	API RP 581 NACE Publication 34108
Fractionator overhead accumulator water ammonium bisulfide content	Sour water from overhead accumulator boot	Wt. % ammonium bisulfide	Ammonium bisulfide corrosion Wet H2S damage	API RP 581
Fractionator overhead accumulator water CN-content	Sour water from overhead accumulator boot	ppm	Ammonium bisulfide corrosion Wet H2S damage	API RP 581
Fractionator overhead accumulator water H2S content	Sour water from overhead accumulator boot	ppm	Ammonium bisulfide corrosion Wet H2S damage	API RP 581
Fractionator overhead accumulator water carbonate content	Sour water from overhead accumulator boot	ppm	Carbonate cracking	API RP 581 NACE Publication 34108
Fractionator overhead accumulator water chloride content	Sour water from overhead accumulator boot	ppm	Ammonium chloride corrosion	
Fractionator overhead accumulator sour water velocity	Flow indicators on sour water from overhead accumulator boot	Flow velocity	Ammonium bisulfide corrosion	API RP 581

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Wet gas compressor water wash rates - intercooler and aftercooler	Wash water flow indicator	Flow rate	Ammonium bisulfide corrosion Ammonium chloride corrosion	
Wet gas compressor polysulfide injection rates - intercooler and aftercooler	Polysulfide flow indication	Flow rate	Ammonium bisulfide corrosion Wet H2S damage	
Wet gas compressor knockout drum(s) sour water pH	Sour water from wet gas compressor KO drum boots	pH	Ammonium bisulfide corrosion Ammonium chloride corrosion Carbonate cracking	API RP 581 NACE Publication 34108
Wet gas compressor knockout drum(s) sour water ammonium bisulfide content	Sour water from wet gas compressor KO drum boots	Wt. % ammonium bisulfide	Ammonium bisulfide corrosion Wet H2S damage	API RP 581
Wet gas compressor knockout drum(s) sour water CN- content	Sour water from wet gas compressor KO drum boots	ppm	Ammonium bisulfide corrosion Wet H2S damage	API RP 581
Wet gas compressor knockout drum(s) sour water H2S content	Sour water from wet gas compressor KO drum boots	ppm	Ammonium bisulfide corrosion Wet H2S damage	API RP 581
Wet gas compressor knockout drum(s) sour water carbonate content	Sour water from wet gas compressor KO drum boots	ppm	Carbonate cracking	API RP 581 NACE Publication 34108
Wet gas compressor knockout drum(s) sour water chloride content	Sour water from wet gas compressor KO drum boots	ppm	Ammonium chloride corrosion	

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Wet gas compressor sour water velocities	Flow indicators on sour water from compressor KO drum boots	Flow velocity	Ammonium bisulfide corrosion	API RP 581
Gas plant overhead accumulator water pH	Sour water from overhead accumulator boots	pH	Ammonium bisulfide corrosion Ammonium chloride corrosion Carbonate cracking	API RP 581 NACE Publication 34108
Gas plant overhead accumulator water ammonium bisulfide content	Sour water from overhead accumulator boots	Wt. %	Ammonium bisulfide corrosion Wet H2S damage	API RP 581
Gas plant overhead accumulator water CN-content	Sour water from overhead accumulator boots	ppm	Ammonium bisulfide corrosion Wet H2S damage	API RP 581
Gas plant overhead accumulator water H2S content	Sour water from overhead accumulator boots	ppm	Ammonium bisulfide corrosion Wet H2S damage	API RP 581
Gas plant overhead accumulator water chloride content	Sour water from overhead accumulator boots	ppm	Ammonium chloride corrosion	
Gas plant overhead accumulator sour water velocities	Flow indicators on sour water from overhead accumulator boots	Flow velocity	Ammonium bisulfide corrosion	API RP 581

Table A5 Example IOWs for HF Acid Alkylation Unit

IOW recommendations for HF Acid Alkylation Units are covered in API RP 751. Refer to API RP 751 for current guidance.

Table A6 Example IOWs for Sulfuric Acid Alkylation Unit

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Water content of feed	Outlet of feed coalescer	Wt. %	Sulfuric acid corrosion	API RP 571 API RP 581
Feed coalescer water pH	Feed coalescer outlet water/ boot water (for feed coalescer located after feed/effluent exchangers)	pH	Sulfuric acid corrosion Identify leak in feed/effluent exchanger	API RP 571 API RP 581
Feed oxygenates	Feed coalescer	ppm	Sulfuric acid corrosion	API RP 571 API RP 581
Feed S	Feed coalescer	ppm	Sulfuric acid corrosion - distillation section overhead	
Feed non-condensables	Feed coalescer	ppm	Sulfuric acid corrosion - distillation section overhead	
Fresh acid strength	Make-up acid	Wt. % H ₂ SO ₄	Sulfuric acid corrosion	API RP 571 API RP 581
Fresh acid iron content	Make-up acid	ppm	Sulfuric acid corrosion	API RP 571 API RP 581
Fresh acid temperature	Make-up acid	Temperature	Sulfuric acid corrosion	API RP 571 API RP 581
Fresh acid velocity	Fresh acid lines	Flow velocity	Sulfuric acid corrosion Hydrogen grooving	API RP 571 API RP 581
Acid strength in reactor/contactor	Acid to settler	Wt. %	Sulfuric acid corrosion	API RP 571 API RP 581
Water content of acid in reactor/contactor	Acid to settler	Wt. %	Sulfuric acid corrosion	API RP 571 API RP 581
Circulating reaction mix velocity	Reactor/ contactor/ settler piping	Flow velocity	Sulfuric acid corrosion Hydrogen grooving	API RP 571 API RP 581

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Reactor/ contactor temperature	Reactor/ contactor TIs	Temperature	Sulfuric acid corrosion	API RP 571 API RP 581
Reactor/ contactor mixer motor amps	Motor power source	Amps	Impeller damage	
Settler operating pressure	Settler	Pressure		
Effluent exchanger outlet temperature	Effluent out of feed/effluent exchanger	Temperature	Sulfuric acid corrosion	API RP 571 API RP 581
Precipitator current	Effluent electrostatic precipitator	Amps	Sulfuric acid corrosion	API RP 571 API RP 581
Precipitator voltage	Effluent electrostatic precipitator	Volts	Sulfuric acid corrosion	API RP 571 API RP 581
Caustic wash section temperature	Caustic wash drum TI	Temperature (minimum to breakdown acid esters)	Sulfuric acid corrosion	API RP 571 API RP 581
Caustic strength	Caustic wash circulating caustic/ alkaline water	Wt. %	Sulfuric acid corrosion	API RP 571 API RP 581
Velocity in caustic wash piping	Caustic wash circulation piping	Flow velocity	Sulfuric acid corrosion Erosion-corrosion	API RP 571 API RP 581
Carryover of acid in Deisobutanizer feed	Deisobutanizer feed from effluent treating	ppm	Sulfuric acid corrosion	API RP 571 API RP 581
Carryover of caustic in Deisobutanizer feed	Deisobutanizer feed from effluent treating	ppm	Caustic Cracking	API RP 571 NACE SP0403
Deisobutanizer Overhead water pH	Water from Deisobutanizer overhead boot	pH	Sulfuric acid corrosion	API RP 571 API RP 581

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Deisobutanizer Overhead water iron	Water from Deisobutanizer overhead boot	ppm	Sulfuric acid corrosion	
Depropanizer Overhead water pH	Water from Depropanizer overhead boot	pH	Sulfuric acid corrosion	
Depropanizer Overhead water iron	Water from Depropanizer overhead boot	ppm	Sulfuric acid corrosion	
Debutanizer Overhead water pH	Water from Debutanizer overhead boot	pH	Sulfuric acid corrosion	
Debutanizer Overhead water iron	Water from Debutanizer overhead boot	ppm	Sulfuric acid corrosion	
Spent acid strength	Spent acid to weathering drum	Wt. %	Sulfuric acid corrosion	API RP 571 API RP 581
Water in spent acid	Spent acid to weathering drum	Wt. %	Sulfuric acid corrosion	API RP 571 API RP 581
Spent acid velocity	Spent acid to weathering drum	Flow velocity	Sulfuric acid corrosion	API RP 571 API RP 581

Table A7 Example IOWs for Delayed Coker Unit

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Feed S	Coker total feed	Wt. % S	Sulfidation Sour water corrosion (acidic) Ammonium bisulfide corrosion Wet H ₂ S damage	API RP 571 API RP 581 API RP 939C
Feed TAN	Coker total feed	Mg KOH/ g of sample	Naphthenic acid corrosion	API RP 571 API RP 581
Feed sodium	Coker total feed	ppm	Heater tube fouling - short term overheat/ stress rupture/ creep	
Coker heater tube metal temperature	Coker heater tube skin TIs	Temperature	Short term overheat/ stress rupture Creep/ Stress rupture	API STD 530 API 579-1/ASME FFS-1
Coker heater coil pressure drop	Coker heater coil PIs	Pressure drop across coils	Short term overheat/ stress rupture	
Coker heater outlet temperature	Coker heater outlet TIs	Temperature	Short term overheat/ stress rupture Sulfidation	API STD 530 API 579-1/ASME FFS-1 API RP 939C
Coker heater coil flow rates	Coker heater coil flow indicators	Flow rate	Short term overheat/ stress rupture	
Coker heater velocity steam injection rate	Steam flow indicators	Flow rate	Short term overheat/ stress rupture	
Coker heater tube velocity during spalling/ decoking	Coker heater coil flow indicators	Flow velocity	Erosion	
Coke drum warm-up temperature prior to switch-in	TIs on condensate from drum	Temperature	Thermal fatigue Fatigue Bulging/ deformation	API TR 934-G

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Coke drum initial quench rate	Quench water flow indicators	Flow rate	Thermal fatigue Fatigue Bulging/ deformation	API TR 934-G
Fractionator side-cut temperatures	Fractionator side-cut TIs	Temperature	Sulfidation Naphthenic acid corrosion	API RP 571 API RP 581 API RP 939C
Fractionator overhead salt point margin	Fractionator overhead TIs	Margin between overhead temperature and calculated salt point	Ammonium chloride corrosion	API RP 571
Fractionator overhead water dew point margin	Fractionator overhead TIs	Margin between overhead temperature and calculated water dew point	Ammonium chloride corrosion	API RP 571
Fractionator overhead water injection rate	Water injection flow indicators	Flow rate	Ammonium chloride corrosion	API RP 571
Ammonium polysulfide in fractionator overhead wash water	APS flow indication	Flow rate	Ammonium bisulfide corrosion Wet H ₂ S damage	API RP 571 API RP 581
Fractionator overhead sour water NH ₃ content	Overhead accumulator boot sour water	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion	API RP 571 API RP 581
Fractionator overhead sour water H ₂ S content	Overhead accumulator boot sour water	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion Wet H ₂ S damage	API RP 571 API RP 581
Fractionator overhead sour water NH ₄ HS content	Overhead accumulator boot sour water	Wt. %	Ammonium bisulfide corrosion	API RP 571 API RP 581

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Fractionator overhead sour water chloride content	Overhead accumulator boot sour water	ppm	Ammonium chloride corrosion	API RP 571 API RP 581
Fractionator overhead sour pH content	Overhead accumulator boot sour water	pH	Ammonium bisulfide corrosion Ammonium chloride corrosion Carbonate cracking	API RP 571 API RP 581 NACE Publication 34108
Fractionator overhead sour water carbonate content	Overhead accumulator boot sour water	ppm	Carbonate cracking	API RP 581 NACE Publication 34108
Fractionator overhead sour water cyanide content	Overhead accumulator boot sour water	ppm	Ammonium bisulfide corrosion Wet H ₂ S damage	API RP 571 API RP 581
Fractionator overhead sour water iron content	Overhead accumulator boot sour water	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion	
Sour water flow velocity	Sour water piping flow indicators	Flow velocity	Ammonium bisulfide corrosion	API RP 571 API RP 581
Compressor interstage and final stage water injection rate	Water injection flow indicators	Flow rate	Ammonium chloride corrosion	API RP 571
Ammonium polysulfide in compressor interstage and final stage wash water	APS flow indication	Flow rate	Ammonium bisulfide corrosion Wet H ₂ S damage	API RP 571 API RP 581

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Compressor interstage and final stage sour water NH3 content	Compressor interstage and final stage knockout drum boot sour waters	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion	API RP 571 API RP 581
Compressor interstage and final stage sour water H2S content	Compressor interstage and final stage knockout drum boot sour waters	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion Wet H2S damage	API RP 571 API RP 581
Compressor interstage and final stage sour water NH4HS content	Compressor interstage and final stage knockout drum boot sour waters	Wt. %	Ammonium bisulfide corrosion	API RP 571 API RP 581
Compressor interstage and final stage sour water chloride content	Compressor interstage and final stage knockout drum boot sour waters	ppm	Ammonium chloride corrosion	API RP 571 API RP 581
Compressor interstage and final stage sour pH content	Compressor interstage and final stage knockout drum boot sour waters	pH	Ammonium bisulfide corrosion Ammonium chloride corrosion Carbonate cracking	API RP 571 API RP 581 NACE Publication 34108
Compressor interstage and final stage sour water carbonate content	Compressor interstage and final stage knockout drum boot sour waters	ppm	Carbonate cracking	API RP 581 NACE Publication 34108

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Compressor interstage and final stage sour water cyanide content	Compressor interstage and final stage knockout drum boot sour waters	ppm	Ammonium bisulfide corrosion Wet H ₂ S damage	API RP 571 API RP 581
Compressor interstage and final stage sour water iron content	Compressor interstage and final stage knockout drum boot sour waters	ppm	Ammonium bisulfide corrosion Ammonium chloride corrosion	
Debutanizer water draw-off	Debutanizer overhead accumulator water draw flow indicator	Flow rate	Ammonium chloride corrosion Sour water corrosion (acidic)	
Coke cutting water/ quench water suspended solids	Cutting water from jet tank	ppm	Erosion-corrosion	
Coke cutting water/ quench water pH	Cutting water from jet tank	pH	Sour water corrosion (acidic)	API RP 571
Coke cutting water/ quench water H ₂ S	Cutting water from jet tank	ppm	Sour water corrosion (acidic)	API RP 571
Coke cutting water/ quench water chloride	Cutting water from jet tank	ppm	Sour water corrosion (acidic)	API RP 571
Coke cutting water/ quench water iron	Cutting water from jet tank	ppm	Sour water corrosion (acidic)	API RP 571

Table A8 Example IOWs for Steam Methane Reformer (Hydrogen Manufacturing) Unit

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Feed gas condensate pH	Feed gas knockout drum	pH	Acidic corrosion - HCl, sour water	API RP 571
Feed gas H2S (if refinery gas)	Feed gas sample	ppm	Sour water corrosion (acidic) Wet H2S damage	API RP 571
Zinc oxide drum inlet temperature	Gas inlet TI	Temperature	HTHA	API RP 941
Zinc oxide drum outlet temperature	Gas outlet TI	Temperature	HTHA	API RP 941
Reformer feed steam to carbon ratio	Feed gas and steam flow indicators	Vol flow rate ratio	Short term overheating - stress rupture Carburization Metal dusting	
Reformer heater tube skin temperatures	Tube skin TIs and infrared measurements	Temperature	Creep/ Stress rupture Short term overheating - stress rupture	API STD 530 API RP 571
Reformer effluent temperature	Effluent TIs	Temperature	Creep/ Stress rupture Short term overheating - stress rupture	API STD 530 API RP 571
Reformer effluent heating and cooling rate	Effluent TIs	Temperature change/ hr.	Thermal shock Thermal fatigue	API RP 571
Reformer effluent transfer line and waste heat boiler metal temperatures (refractory lined)	Tube skin TIs and infrared measurements	Temperature	Creep/ Stress rupture Short term overheating - stress rupture HTHA	API RP 571 API RP 941

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Water level in waste heat boiler	Level indicators on waste heat boiler water side	Level	Short term overheat/ Stress rupture	
Inlet and outlet temperatures to effluent equipment such as high temperature shift, low temperature shift, methanator and exchangers	Inlet and outlet TIs	Temperature	HTHA	API RP 941
Reformer effluent gas to from low temperature shift to CO2 removal section	Effluent gas TIs at outlets of vessels and exchangers	Temperature	HTHA CO2 corrosion	API RP 571 API RP 581 API RP 941
Process condensate pH	Process condensate to the deaerator	pH	CO2 corrosion	API RP 581
Process condensate chloride level	Process condensate to the deaerator	ppm	Chloride SCC	API RP 571
Process condensate NH3 level	Process condensate to the deaerator	ppm	NH3 SCC (brass)	API RP 571
CO2 removal (if hot potassium carbonate solvent process): Soluble Fe V inhibitor valency Solvent flow rate Air injection Colorimetric testing	Lean solution Lean solution Lean solution Lean solution Lean solution/ regenerator outlet	ppm valency flow rate flow rate color comparison	CO2 corrosion	Refer to process licensor
CO2 removal (if amine): Refer to amine unit IOWs	Amine section of unit			

Table A9 Example IOWs for Amine Unit

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Documents for Limits
Lean amine concentration	Lean amine from regenerator	wt. %	Amine corrosion	API RP 581 API RP 945
Lean amine water content	Lean amine from regenerator	wt. %	Amine corrosion	
Lean amine acid gas loading	Lean amine from regenerator	mol acid gas/ mol amine	Amine corrosion	API RP 581
Lean amine velocity	Lean amine piping	Flow rate/ flow velocity	Amine corrosion/ erosion-corrosion	API RP 571 API RP 581 API RP 945
Amine anions and metals (e.g. bicine, formate, K, Na, etc. as recommended by amine supplier)	Lean amine	ppm	Amine corrosion	Consult with amine supplier
Regenerator bottoms	Lean amine from regenerator	Temperature	Amine corrosion	API RP 581 API RP 945
Amine heat stable salt (HSS)	Lean amine	wt. %	Amine corrosion	API RP 571 API RP 581 API RP 945
Amine iron content	Lean amine	ppm	Amine corrosion	
Amine total suspended solids (TSS)	Lean amine	ppm	Amine corrosion/ erosion-corrosion	
Amine chloride concentration	Lean amine	ppm	Chloride stress corrosion cracking/ amine corrosion	
Rich amine loading	Contactora/Absorber bottoms	mol acid gas/ mol amine	Amine corrosion	API RP 581 API RP 945

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Documents for Limits
Rich amine velocity	Rich amine piping	Flow rate/ flow velocity	Amine corrosion/ erosion-corrosion	API RP 571 API RP 581 API RP 945
Regenerator reboiler steam	Steam to reboiler	Pressure or temperature	Amine corrosion	API RP 571 API RP 581 API RP 945
Regenerator reboiler return temperature	Amine outlet from reboiler	Temperature	Amine corrosion	API RP 571 API RP 581 API RP 945
NH ₄ HS in regenerator overhead reflux water	Regenerator overhead reflux drum water	wt. %	Ammonium bisulfide corrosion	API RP 581
CN concentration in regenerator overhead reflux water	Regenerator overhead reflux drum water	ppm	Ammonium bisulfide corrosion and wet H ₂ S damage	API RP 581
Regenerator overhead reflux water purge rate	Purge line	vol. %	Ammonium bisulfide corrosion	
Regenerator overhead reflux water flow velocity	Regenerator overhead condenser to regenerator tower return	Flow rate/ flow velocity	Ammonium bisulfide corrosion	API RP 581
Acid gas from regenerator overhead reflux drum to SRU	Acid gas from reflux drum	Temperature	Ammonium bisulfide corrosion/ sour water corrosion (acidic)	

Table A10 Example IOWs for Sour Water Stripper Unit

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Feed water pH	Combined feed to unit	pH	Ammonium bisulfide corrosion Sour water corrosion (acidic)	API RP 571 API RP 581
Feed water H2S	Combined feed to unit	Wt. %	Ammonium bisulfide corrosion (stripper tower overhead) Wet H2S damage	API RP 571 API RP 581
Feed water NH3	Combined feed to unit	Wt. %	Ammonium bisulfide corrosion (stripper tower overhead) Wet H2S damage	API RP 571 API RP 581
Feed water chloride	Combined feed to unit	ppm	Chloride SCC Ammonium chloride corrosion	API RP 581
Feed water cyanide	Combined feed to unit	ppm	Ammonium bisulfide corrosion (stripper tower overhead) Wet H2S damage	API RP 571 API RP 581
Sour water reflux pH	Stripper overhead accumulator	pH	Ammonium bisulfide corrosion APS decomposition Carbonate cracking	API RP 581 NACE Publication 34108
Sour water reflux NH4HS	Stripper overhead accumulator	Wt. %	Ammonium bisulfide corrosion Wet H2S damage	API RP 571 API RP 581

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Sour water reflux cyanide	Stripper overhead accumulator	ppm	Ammonium bisulfide corrosion (stripper tower overhead) Wet H2S damage	API RP 571 API RP 581
Stripper overhead ammonium polysulfide injection rate	APS injection flow indicator	Flow rate	Ammonium bisulfide corrosion Wet H2S damage	API RP 571 API RP 581
Stripper overhead condenser outlet temperature	TI on outlet piping from condenser	Temperature	Ammonium bisulfide corrosion Hydriding (titanium tubes)	API RP 571
Stripper overhead sour water velocity	Sour water from overhead accumulator	Flow velocity	Ammonium bisulfide corrosion	API RP 571 API RP 581
Sour gas temperature	Sour gas to SRU	Temperature	Ammonium bisulfide corrosion Salt deposition	
Stripped sour water pH	Stripped sour water from stripper tower	pH	Caustic cracking Reboiler corrosion	NACE SP0403

Table A11 Example IOWs for Sulfur Recovery Unit

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Sour gas temperature	Sour gas to SRU	Temperature	Ammonium bisulfide corrosion Salt deposition	
Reaction furnace temperature	Reaction furnace TIs in process gas	Temperature	Refractory damage Sulfidation Burner tip oxidation	API RP 571 API RP 581
Metal temperature of refractory lined equipment	Metal temperature TIs and infrared measurements	Temperature	Sulfidation Flue gas acid dew point corrosion	API RP 571
Unlined steel equipment in process gas	Process TIs	Temperature	Sulfidation	API RP 571
Waste heat boiler water level	Waste heat boiler water level indicator	Level	Short term overheat/ stress rupture	
Condenser outlet temperatures	Outlet TIs from condensers	Temperature	Flue gas acid dew point corrosion	
Boiler feed water to sulfur condensers	BFW inlet TIs	Temperature	Flue gas acid dew point corrosion	

Table A12 Example IOWs for Ethane Cracking Units

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Olefins in the hydrocarbon feed	Hydrocarbon feed	Wt. %/ ppm	Coking in the heater tubes leading to an increase in high temperature damage mechanisms (Creep, Carburization, Sigma Phase, Oxidation, Nitriding, Metal Dusting) and thermal fatigue.	Based on the specific design of the unit. Consult Process Engineering and Licensor.
Hydrocarbon Feed rate	Hydrocarbon feed	Flow rate	<ol style="list-style-type: none"> 1. Coking in the heater tubes leading to an increase in high temperature damage mechanisms (Creep, Carburization, Sigma Phase, Oxidation, Nitriding, Metal Dusting) and thermal fatigue. 2. Short term overheat in the lower section of the convection coils and in the radiant coils. 	Based on the specific design of the unit. Consult Process Engineering and Licensor.
Steam Injection rate	Steam injection into the heater coil	Flow rate rate/ Steam to hydrocarbon ratio	<ol style="list-style-type: none"> 1. Coking in the heater tubes leading to an increase in high temperature damage mechanisms (Creep, Carburization, Sigma Phase, Oxidation, Nitriding, Metal Dusting) and thermal fatigue. 2. Short term overheat in the lower section of the convection coils and in the radiant coils. 	Based on the specific design of the unit. Consult Process Engineering and Licensor.
DMS Injection Rate	DMS injection into the heater coil	Injection rate	Coking in the heater tubes leading to an increase in high temperature damage mechanisms (Creep, Carburization, Sigma Phase, Oxidation, Nitriding, Metal Dusting) and thermal fatigue.	Based on the specific design of the unit and process conditions present. Consult Process Engineering and Licensor.
Convection and Radiant Tube	Inlet and outlet of the radiant	Temperature	Coking in the heater tubes leading to an increase in high temperature damage	Based on the specific design of the unit and

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Process Temperature	and convection tubes		mechanisms (Creep, Carburization, Sigma Phase, Oxidation, Nitriding, Metal Dusting) and thermal fatigue.	process conditions present. Consult Process Engineering and Licensor. API RP 571
Convection and Radiant Tube Metal Temperature	Inlet and outlet of the radiant and convection coils as well as locations along the length of the coils	Temperature	Coking in the heater tubes leading to an increase in high temperature damage mechanisms (Creep, Carburization, Sigma Phase, Oxidation, Nitriding, Metal Dusting) and thermal fatigue.	Based on the specific design of the unit, metallurgy, and process conditions present. Consult Process Engineering and Licensor. API RP 571
Primary Quench Exchanger Outlet Temperature	Primary Quench Exchanger outlet	Temperature	Coking and plugging of PQE's indicating decoking is required. Failure to decoke increases potential for high temperature damage mechanisms (Creep, Carburization, Sigma Phase, Oxidation, Nitriding, Metal Dusting) in the piping components upstream of the PQE's.	Based on the specific design of the PQE and process conditions present. Consult Process Engineering and Licensor. API RP 571
Pressure Drop across the Radiant Tubes	Radiant tube inlet and outlet	Pressure drop	Coking and plugging of the radiant coils indicating decoking is required. Failure to decoke increases potential for high temperature damage mechanisms (Creep, Carburization, Sigma Phase, Oxidation, Nitriding, Metal Dusting) and short term overheat.	Based on the specific design of the system and process conditions present. Consult Process Engineering and Licensor.
Pressure Drop across PQE Tubes	Primary Quench Exchanger tube side inlet and outlet	Pressure drop	Coking and plugging of PQE's indicating decoking is required. Failure to decoke increases potential for high temperature damage mechanisms in the piping components upstream of the PQE's.	Based on the specific design of the system and process conditions present. Consult Process Engineering and Licensor.

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Number of Furnace Trips	Furnace trips	Number of Trips	Thermal Fatigue	API 579-1/ASME FFS-1
Spring Hanger Calibration	Springer hanger calibration	Travel Limits - distance	Creep, Thermal Fatigue.	Manufacturer guidelines
H2S in the Fuel Gas	Fuel Gas	ppm	1. Flue Gas Corrosion in the Hydrocarbon Feed Preheat and BFW Preheat coils. 2. Polythionic Acid SCC on austenitic stainless steel tube OD.	API RP 571
CO / CO2 content in the cracking heater effluent during normal operations	PQE Effluent	Vol %	CO and CO2 levels in the cracking heater effluent are indicators of the surface passivation level of the radiant coils and are indicators for coking of the radiant tubes. Excessive coking leads to an increase in high temperature damage mechanisms (Creep, Carburization, Sigma Phase, Oxidation, Nitriding, Metal Dusting) and thermal fatigue.	Based on the specific metallurgy of the unit and process conditions present. Consult Process Engineering and Licensor.

Table A13 Example IOWs for Boiler Water Treatment and Return Condensate Quality

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
BFW Quality - pH	Feedwater	pH	General corrosion and pitting	ASME VII EPRI 1021767
BFW Quality - Conductivity	Feedwater	μS/cm (μm mhos/cm)	Scaling/Deposits Control	ASME VII EPRI 1021767
BFW Quality - Dissolved oxygen	Feedwater	Oxygen (ppb)	General corrosion and pitting	ASME VII EPRI 1021767
BFW Quality - Total Iron in the BFW	Feedwater	Iron (ppmw)	Deposits leading to under deposit corrosion	ASME VII EPRI 1021767
BFW Quality - Copper in the BFW	Feedwater	Total Copper (ppmw)	Deposits leading to under deposit corrosion	ASME VII EPRI 1021767
BFW Quality - Silica in the BFW	Feedwater	SiO ₂ (ppm)	Scaling and deposits / Turbine Blade Fouling	ASME VII EPRI 1021767
Boiler Water Quality – Sodium and Potassium in the BFW	Boiler Drum Water	ppm	Corrosion / Environmental Cracking	ASME VII EPRI 1021767
BFW Quality - Chloride	Boiler Drum Water	ppm	Acidic Corrosion	ASME VII EPRI 1021767
Boiler Water Quality - Sulfate	Boiler Drum Water	ppm	Scaling/Deposit Control	ASME VII EPRI 1021767
BFW Quality - Total Hardness of the BFW	Feedwater	Calcium and magnesium salts expressed as CaCO ₃ equivalent (ppmw)	Scaling/Deposit Control	ASME VII EPRI 1021767

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Condensate Quality-pH	Return condensate	pH	General Corrosion and Pitting	ASME VII EPRI 1021767
Condensate Quality-Iron	Return condensate	ppb	Deposits leading to under deposit corrosion Corrosiveness of the condensate	ASME VII EPRI 1021767
Condensate Quality-Copper	Return condensate	ppb	Deposits leading to under deposit corrosion Accelerate corrosion of copper alloys (heat exchanger tubes)	ASME VII EPRI 1021767
Condensate Quality-Organics and Hydrocarbons	Return condensate	ppm	Scaling/Deposit Control Potential leaks in the system	ASME VII EPRI 1021767

Table A14 Example IOWs for Fired Heaters

IOW Description	Typical Location	Parameter	Damage Mechanism Controlled	Industry Guidance Document
Process minimum inlet temperature	Heater inlet	Margin of measured temperature above calculated vaporization (dry point) temperature (see note 3.)	Localized fouling, corrosion, creep or short term overheat at vaporization point. Prevent full vaporization occurring in the heater tubes.	
Maximum tube metal temperature (See note 4)	Radiant and convection coils	Temperature	Creep/ Stress rupture Short term overheat Corrosion Fouling	API STD 530 API 579-1/ASME FFS-1-1
Minimum stack flue gas temperature	Stack	Temperature	Flue gas dew point corrosion	API RP 571 API STD 560
Air preheat flue gas outlet minimum temperature	Air preheater outlet	Temperature	Flue gas dew point corrosion	API RP 571 API STD 560

Heater minimum pass flow rates	Pass flow indicators	Flow rate	Short-term overheating - Stress rupture Creep	API STD 530 API 579-1/ASME FFS-1-1
Heater pass flow rate differential	Pass flow indicators	% difference	Short-term overheating - Stress rupture Creep	API STD 530 API 579-1/ASME FFS-1-1
Heater pass outlet temperature differential	Outlet TIs	% difference or Δ temperature	Short-term overheating - Stress rupture Creep	API STD 530 API 579-1/ASME FFS-1-1

Notes:

1. These example IOWs for fired heaters are to avoid tube leaks and ruptures. IOWs related to combustion, efficiency and heater structural components are not included here. The reader is referred to API RP 556, Instrumentation, Control, and Protective Systems for Gas Fired Heaters, for additional guidance on conditions causing heater failures and incidents. See especially Annex A and Tables 1 and 2.
2. Refer to the unit specific example IOWs in this Annex for IOWs that may be applied to heaters in generic types of units. Corrosion mechanisms associated with generic units are covered in the unit specific example IOWs.
3. Naphtha Hydrotreater Units are an example of where this IOW should be considered.
4. Critical, Standard, and Informational IOW limits are often established for fired heater tube metal temperatures.

Annex B

(informative)

Sample Format for Recording IOWs

IOW Description	IOW type	Parameter	Minimum Limit	Maximum Limit	Monitoring interval	Time allowed outside of limit before response	Possible consequences of deviation outside limits	Response required/recommended	Who responds
i.e. Fractionator overhead temperature, exchanger inlet temperature, wash water rate, etc. (see Annex A for examples)	Informational, standard or critical	Temperature, pressure, concentration, pH, etc. (see Annex A for examples)	Lower limit	Upper limit	Continuously, hourly, daily, weekly, monthly, etc.	Hour, day, week, month, etc.	Explains what damage and consequence may occur from deviation outside of limits	Explains actions to be taken and may include actions by operators, process, inspection, SMEs, etc.	Operators, process, inspection, SMEs, etc.

Annex C (informative)

Example of an IOW Development for a Heat Exchanger

IOWs are typically developed on a unit basis or for an entire system or corrosion loop. There are two primary ways in which IOW limits are determined for a given operating period; 1) historical operating basis (if favorable reliability has occurred) and 2) limiting equipment / component basis in the system or corrosion loop.

Historical Operating Basis - In cases where good long-term corrosion and reliability performance have been achieved, a simple approach for establishing acceptable operating limits is to review the past operating conditions and set upper (and lower) limits based on the operating history. An example for this approach is a system or corrosion loop where the only damage mechanism is sulfidation and with good long-term reliability, low corrosion rate and good quality inspection records. This would allow setting the feed sulfur and operating temperature limits based on previous operation conditions with an allowance for typical fluctuation of the operation. For example, with a previous average feed sulfur content of 0.37 wt.% and with historical variation of +/- 0.10 wt.%, the IOW standard maximum limit could be set at 0.47 wt.% sulfur in the feed without concern for accelerated corrosion at historical operating temperature.

Limiting Equipment Basis - In systems or corrosion loops that have more aggressive corrosion, the limits should be set based on the life limiting equipment or component in the system. The following example highlights in detail how an IOW might be formulated for a system around one equipment that was determined to be the limiting component.

In this hypothetical example, a crude unit fractionator tower bottoms exchanger (X-1) is potentially under alloyed for future service (sulfidic corrosion concern). Based on the current feed slate to the unit, the actual measured corrosion rate is acceptable, but the refinery is planning to process higher sulfur crudes soon. This exercise will look at the data development and thought process involved to set appropriate IOWs for this hypothetical exchanger.

Step 1 – Define the Operation

This X-1 exchanger is utilized in the atmospheric gas oil (AGO) stream which receives a steady diet of blended crudes containing 0.30 % sulfur and minimal naphthenic acid. The operating temperature is 600 °F with little to no temperature variation. There is a desire to increase the total sulfur in the AGO in the future from 0.30 to 0.50 wt.% and increase the operating temperature from 600 °F to 650 °F with no increase in TAN. The next full outage that would provide an opportunity to inspect, repair or replace this exchanger is 5 years from the proposed change.

Step 2 – Corrosion/Damage Mechanism Identification

The X-1 exchanger was fabricated from 1-1/4 Cr steel on the shell side (receives an AGO stream) and operates at 600 °F with an estimated 0.30 wt.% sulfur (total). The primary damage mechanism of concern for both current and future operation is sulfidation; naphthenic acid corrosion has not been a concern in this Unit. The estimated corrosion rate potential utilizing the Modified McConomy Industry curves is approximately 7.6 mpy (the current measured corrosion rate is 5 mpy). Differences between the theoretical/potential rate and the measured/observed rate are likely due in part to the amount of reactive sulfur available in the specific Crude slate. For the future operation of 0.50 wt.% sulfur and an increase the operating temperature to 650 °F the

estimated corrosion rate is 16 mpy. The metallurgy for this exchanger may be under-designed for the new application.

Step 3 – Determine the parameters that will potentially affect the reliability of this Equipment (Long Term)

- Crude slate/blend.
- Total sulfur at AGO cut.
- Reactive sulfur at AGO cut.
- Total acid number (TAN) at AGO cut.
- Operating temperature (and time at temperature, if variable) at X-1 shell.
- Velocity of process fluid.

Step 4 – Define the Critical Operating Parameters (measurable and controllable)

Sulfidic corrosion is a co-dependent on the amount of reactive sulfur present and the temperature for a given material of construction. Sulfidation rates may be accelerated by naphthenic acid and velocity of the process fluid, both of which act to remove the protective iron sulfide scale that develops as a process of sulfidic corrosion. In general, the refinery does not monitor reactive sulfur species but relies on total sulfur measurements. In this case, there is a moderate to high corrosion rate potential based on a theoretical analysis. The operating temperature and total sulfur content of the AGO stream are the primary operating parameters that will be targeted (controllable by the crude slate being run).

- Total sulfur at AGO cut (primary IOW).
- Operating temperature (and time at temperature, if variable) at X-1 shell.

Step 5 – Reliability Factor Basis (Considerations)

In its current operation, this exchanger has a calculated remaining life of 15 years based on the historical measured corrosion rate (remaining corrosion allowance of 0.075 in. divided by the measured rate of 5 mpy). Utilizing the estimated corrosion rate of 16 mpy for future operation, the remaining life drops to 4.6 years. To ensure that the exchanger makes it to the next outage or shutdown (5 years) it was decided to control the corrosion rate to obtain a 6-year remaining life (1-year additional reliability factor).

Step 6 – Set Limits on the Critical Reliability Operating Parameters

Based on a desired operating period of 5 years (outage or shutdown interval) with a 1-year reliability factor, and the remaining or usable corrosion allowance of 0.075 in., it was determined that an allowable corrosion of 12.5 mpy was the maximum rate that could be sustained to make the 6-year run. Two options were given the operations department, 1) control the operating temperature to 620 °F with a total sulfur content of 0.5 wt.% or 2) operate at 650 °F and control the total sulfur in the blend at the AGO cut to 0.2 wt.%. In this case, because there is enough safety factor remaining even when the thickness reaches the Code t_{min} value, this was determined to be a medium risk Standard IOW limit.

Annex D

(informative)

Barriers to Successful IOW Implementation

This annex gives a listing of barriers leading to inadequate creation and implementation of IOWs. These issues have been identified during API Process Safety Site Assessment Program. This annex can be used as a checklist when establishing, reviewing or improving site IOW work processes.

- Over reliance on contractors to collect data and suggest IOWs without enough operator-user involvement and validation. (See 8.2.8)
- Insufficient input and validation from owner SMEs resulting in unrealistic values for operating parameters and missing IOWs. (See 8.4)
- Insufficient support from operator-user's operations and process engineering organizations, due to workload or the plant management not stressing the priority the IOW project. (See 8.2)
- Incomplete participation of knowledgeable, experienced and skilled people on the team to create IOWs. This includes:
 - Process SME for the process unit under consideration
 - Experienced operator
 - Corrosion/materials specialist knowledgeable in the process
 - Individual who knows about industry incidents related to the process unit under consideration.

(See 8.2)

- Failure to complete a comprehensive damage mechanism review as the first step (see examples in API RP 970) (See 5.4)
- Operator-user's lack of an agreed generic templates for the IOWs needed for each process unit (see Annex A)
- Operator-user not having a site practice and process for integrating the new IOWs with existing SOLs, ROLs, OEs, etc. (See 8.1)
- Operator-user's lack of a standard template to guide the IOW work process (see Annex B for an example)
- Lack of a defined work process for implementation of IOWs (See 8.1)
- Not forecasting or planning for new sample stations, instruments and analyzers that will be needed, slowing implementation. (See Section 11)
- Lack of automated communication method to appropriate stakeholders when there is an exceedance. (See 5.10)
- Failure to define who does what to respond to exceedances besides what the operator actions (including Informational IOWs). (See 8.1)

- Insufficient Informational IOWs that engineers should know about and trend to get early warning of issues. (See 4.2.3)
- Management setting unrealistic deadlines for the IOW project leading to poor results to meet the deadline. Often results from lack of an implementation plan and timeline before such deadlines are established. (See 13.2)
- Lack of clarity about what completion of the IOW project means. Following are insufficient definitions:
 - Considering the development of IOWs to be project completion
 - Handing the IOW list to operations to implement
 - Implementing only IOWs that can be implemented without any capital investment in sample stations, instruments, etc. that are needed.

(See 13.2)

- Lack of adequate alarm rationalization being included in the implementation process so that the project does not set up “alarm flood” situations when integrated with existing operating windows. (See 11.3)
- Lack of prioritizing maintenance requirements on instruments, analyzers, or sample stations associated with each IOW. (See Section 11)
- Lack of follow-up meetings to discuss IOW exceedances and learning from the trends. Periodic management meetings on SOL/Critical level exceedances are good practice. (See 8.1)
- Lack of review of IOWs that are consistently being exceeded and lack of an action plan to deal with them. (See 8.1)
- Failure to take corrective action when data is not being recorded to monitor IOW’s. (See 13.2)
- Lack of operator training on the consequence of IOW exceedances. (See Section 10)
- Lack of an periodic health review of the IOW program. (See 13.2)
- Failure to review or adjust IOW established limits following failures /leaks or near misses. (See 13.2)
- Insufficient accountability for the IOW implementation program. One individual should be assigned the accountability for the entire IOW program from beginning to full implementation in the field. (See 13.2.)

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