

## The International Association for the Properties of Water and Steam

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### **Technical Guidance Document: Air In-leakage in Steam–Water Cycles**

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#### Summary

This Technical Guidance Document considers the phenomenon of air in-leakage (AIL) in fossil, combined cycle / HRSG, and biomass plants. It covers the importance of AIL to the performance and cycle chemistry control of generating plants. The sources of AIL are delineated as well as the background science. The monitoring equipment/techniques are provided in Section 4. Controlling guidance for AIL in the most common generating plants worldwide is covered in Section 6, as well the customization aspects for other plants with varying equipment in Section 7.

The document represents the accumulated experience of the IAPWS Power Cycle Chemistry (PCC) Working Group with representation from 24 countries.

This document contains 38 pages, including this cover page.

Further information about this Technical Guidance Document and other documents issued by IAPWS can be obtained from the Executive Secretary of IAPWS (Dr. R.B. Dooley, [bdooley@iapws.org](mailto:bdooley@iapws.org)) or from <http://www.iapws.org>.

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## 1. Nomenclature and Definitions

Term	Alternative or Acronym	Definition
Air-cooled Condenser	ACC	Direct dry cooling system where steam is condensed inside air-cooled finned tubes.
Air in-leakage	AIL	Flow of surrounding air into the shell side of the condenser and other components under sub-atmospheric pressure.
Air Removal Section of condenser	ARS	Component of water-cooled or air-cooled condenser where non-condensable gases are extracted under vacuum.
All-volatile treatment	AVT  AVT-R  AVT-O	Conditioning regime in which only volatile alkalizing agents are added to the feedwater (commonly ammonia but volatile alkalizing amines may also be employed). May be either: <ul style="list-style-type: none"> <li>• Reducing conditions (a reducing agent is added)</li> <li>• Oxidizing conditions (no reducing agent used)</li> </ul>
Caustic Treatment	CT	Involves addition of NaOH to the boiler or HRSG evaporator
Condensate		Water that derives from the condensation of steam after expansion in the steam turbine and passage through a condenser or process heat exchanger
Conductivity	Specific Conductivity (SC) Conductivity (C)	Electrical conductivity of the water sample measured directly without any treatment
Conductivity after cation exchange	CACE  Acid Conductivity  Cation Conductivity	Electrical conductivity of the water sample after passing through a strongly acidic cation exchanger in the H <sup>+</sup> form
Degassed conductivity after CACE	DCACE	Conductivity after cation exchange of a water sample from which volatile weak acids (mostly CO <sub>2</sub> ) have been removed

Drum boiler or drum-type HRSG		Boiler in which steam (generated in heated evaporator tubes) is separated from water in an unheated horizontal pressure vessel (drum); the liquid water is recirculated to the evaporator tubes
Economizer	ECON	First heat transfer section in boiler/HRSG to heat feedwater; located in the cold end of the plant
Feedwater	FW	Water that is pumped into a boiler or HRSG to balance the steam production
Film Forming Amine	FFA	Amine added to the water / steam cycle to form a hydrophobic film on the internal surfaces
Film Forming Amine Product	FFAP	Commercially available FFA material
Film Forming Product	FFP	Film forming substance, not based on an amine, added to the water / steam cycle to form a hydrophobic film
Film Forming Substance	FFS	Defined chemical molecule with film forming properties, including FFA, FFAP and FFP
Flow-accelerated Corrosion	FAC	In this document, defined as accelerated chemical dissolution of magnetite on the surface of carbon steel components as a result of flow and turbulence characteristics
Heat Recovery Steam Generator	HRSG	Steam generator using heat transfer from the exhaust gas of a combustion (gas) turbine
Jet Condenser (or mixing-type condenser)		Type of condenser where there is direct contact between the exhaust steam and cooling water
Indirect Dry Cooling		Type of closed cooling system that includes a water-cooled condenser, and a dry cooling tower that incorporates water-to-air heat exchangers

Heller Indirect Dry Cooling	Heller	Type of indirect dry cooling system that includes a water-cooled jet condenser in combination with a dry cooling tower that incorporates water-to-air heat exchangers
Makeup Water	MU	Water that is added to compensate for losses of water and steam in the boiler system
Once-through Boiler or HRSG	OTSG	Steam generator in which output steam is generated from input water by complete evaporation (no recirculation of boiler water)
Oxygenated Treatment	OT	Conditioning regime in which oxygen and ammonia are added to the feedwater
Parts per billion Parts per million	ppb, $\mu\text{g/L}$ ppm, $\text{mg/L}$	In this document, computed as mass fraction of a constituent in steam or in water (mass constituent/total mass)
Phosphate treatment	PT	Conditioning regime for drum boilers in which alkalinity in the boiler is achieved by dosing with trisodium phosphate (TSP)
Stress corrosion cracking	SCC	A cracking mechanism that can occur in the steam turbine phase transition zone (PTZ)
Sub-cooling of condensate		Difference between the steam saturation temperature and condensate outlet temperature in a condenser
Sub-cooling of steam-air mixture in a condenser		The difference between steam saturation temperature at the total pressure and the actual mixture temperature at the air extraction point.
Terminal Temperature Difference	TTD	Final temperature difference between media interacting in a heat exchanger. TTD measures the efficiency of heat exchange.
Under Deposit Corrosion	UDC	Corrosion mechanisms which occur within heavy deposits on the waterwall and evaporators of a sub-critical plant

## 2. Introduction: Purpose of Document and How to Use It

The purpose of this document is to provide guidance on the detection and measurement of air in-leakage (AIL) in reference to the optimum cycle chemistry control and maximum thermal cycle efficiency in a broad suite of generating plants. Section 4 contains information for locating and measuring AIL. Section 6 contains the guidance on how plant operators can control AIL using these techniques.

IAPWS has in recent years issued a series of Technical Guidance Documents (TGD) for the cycle chemistry control of conventional (fossil, biomass, and waste fuels) and combined cycle plants. These documents (including this one) can be applied to cogeneration plants as well as conventional fossil and combined cycle/HRSG plants [1-8].

This Technical Guidance Document is designed to supplement the IAPWS documents on cycle chemistry treatments to ensure that air in-leakage and any resulting chemical effects at key locations in the plant are properly monitored, maintained, and controlled using adequate sampling and the correct analytical techniques and methodology. It can be used directly by chemists and plant operators, and will be useful for the development of guidelines at the international, national, company, and manufacturer level.

The primary objectives of this document for use in conventional and combined cycle/HRSG plants are:

- to highlight the problems that can exist with cycle chemistry and plant thermal efficiency when air in-leakage is elevated,
- to indicate how these problems occur and how they can be avoided, and
- to illustrate key plant locations where sampling and monitoring should be conducted.

It is emphasized that this is an IAPWS Technical Guidance Document representing the cumulative experience of IAPWS Power Cycle Chemistry (PCC) Working Group members, and as such should be regarded as guidance for operating cycle chemistry limits for plants under stable operating conditions. This guidance is customizable to units that cycle and those that have extensive shutdown periods. This guidance document can form the basis of, but should not restrict, other derivative guidelines around the world.

## 3. Air In-leakage

This section provides background on air in-leakage (AIL) in conventional and combined cycle generating plants. It includes general and scientific aspects of AIL, major sources of AIL, and on locating and measuring AIL. The cycle chemistries used in these plants are also introduced.

### 3.1 Background

The phenomenon of air in-leakage affects both the cycle chemistry and power plant productivity. Air in-leakage (AIL) into a power plant cycle, in excess of IAPWS Guidance for oxygen and/or design specifications, is a common problem for both conventional and combined cycle plants of all sizes. It reduces both plant capacity and efficiency (productivity), contributes to corrosion in the boiler and other equipment (e.g., feedwater heater), and makes control of chemistry relatively more

difficult. Air in-leakage often contributes to sub-cooling of the condensate and to increased concentrations of dissolved oxygen and other contaminants in condensate. Effective control of condenser air in-leakage is essential to cycle chemistry optimization and to attaining the highest possible levels of plant generation capacity and efficiency.

One of the IAPWS stated objectives is to provide technical guidance, obtained by international consensus of experts, on cycle chemistry as well as various aspects of technology associated with steam power cycles in conventional, combined cycle, and nuclear plants and other industrial applications. A reduction in air in-leakage will always translate into better thermal cycle performance. Improvement of air in-leakage will also be beneficial in reducing problems caused by poor cycle chemistry control and corrosion due to contaminants in the improperly managed system. In plants utilizing copper alloys in the feedwater system, optimum AIL will help control corrosion of these alloys and minimize the transport of copper corrosion products. Although the costs associated, either directly or indirectly, with air in-leakage are extremely high, many plants experience inadequate control of AIL.

**THIS DOCUMENT PROVIDES TECHNICAL GUIDANCE TO PRIMARILY HELP CONVENTIONAL, COMBINED CYCLE/HRSG, AND NUCLEAR POWER PLANTS MEET THE IAPWS CYCLE CHEMISTRY GUIDELINES WITH RESPECT TO AIR IN-LEAKAGE. HOWEVER, SUCH ENDEAVOR WILL LIKELY HAVE A SECONDARY BENEFIT, THAT OF IMPROVING THE OVERALL PLANT EFFICIENCY / HEAT RATE.**

### **3.2 Definition of Air In-leakage**

Regardless of the type of fuel used, power generation turbines are driven by steam generated in a boiler. The boiler converts liquid water to steam, spinning the turbine and in turn driving the generator that produces electrical power. After leaving the turbine, the two-phase mixture of steam/water is sent through a heat exchanger to be condensed back to liquid water, which is then returned to the boiler to re-start the cycle. There are several ways to achieve this condensation:

- Shell-and-tube heat exchanger using cooling water (e.g., surface condenser, wet surface air cooler/condenser).
- Air-cooled condensers (ACCs).
- Jet condenser in closed circuit with dry cooling tower (Heller System).

The type of condenser influences the possible AIL locations due to its design and function, and also the eventual chemical effects that may result from AIL. As such, each system needs to be addressed separately.

AIL can also occur at other locations, such as extraction pump seals, and have a different effect than AIL into the condenser.

Air and non-condensable gases are major challenges in a steam plant. Both may hinder a steam system's operation and performance. Not removing air and non-condensable gases from the steam system can reduce heat transfer efficiencies by as much as 20% depending on the air concentration in the steam system. The release of latent energy (to condensate) in the steam components occurs on the heat transfer surface, which is where heat is being transferred due to the temperature difference (the driving force). As the steam component heat transfer consumes the latent energy, the steam condenses to a liquid (condensate); the condensate is drained away by gravity, but the

non-condensable gases and air remain in the system and form a stagnant film on the walls of the heat transfer surface, thus creating a resistance.

The heat available for conversion in a turbine is equal to the difference between the heat content in steam per unit mass at the inlet and the heat content in the steam per unit mass at the outlet. The heat content in steam per unit mass increases with increasing temperature and pressure and decreases with lower temperature and pressure. Therefore, a lower steam pressure in the condenser (which is the exit point for the steam entering the system) makes more heat available for conversion into mechanical energy, and thus increases the efficiency of the steam turbine.

To maximize thermal efficiency that corresponds to a minimum (design) backpressure in the low pressure section of the turbine, a suitable vacuum is maintained in the condenser (i.e., the efficiency is to a great extent controlled by the pressure differential across the steam turbine and condenser). It can be easily seen that this vacuum promotes the flow (leakage) of surrounding air into the shell side of the condenser (the side under vacuum). This is defined as condenser *air in-leakage* (AIL).

This air in-leakage in the turbine-condenser system degrades the pressure differential and can easily result in significant power losses. Furthermore, the surrounding air is composed mainly of nitrogen, oxygen, and carbon dioxide gases but may often comprise other chemical species. Many power plants are sited in areas with surrounding contaminated air such as those in sea coastal areas and industrial areas (e.g., chemical plants, refineries), where additional, corrosive contaminants may be introduced. As an example, it was determined by a North American combined cycle/HRSG power plant sited adjacent to a busy international airport runway, experiencing heavy air in-leakage, that very high levels of NO<sub>x</sub>, SO<sub>x</sub>, chloride, and other deleterious ions were entering the steam cycle.

Since a condenser operates under vacuum, non-condensable gases will migrate towards the condenser. The non-condensable gases consist mostly of air that has leaked into the cycle from components that are operating below atmospheric pressure (this is discussed further in Section 3.5). These gases can also result from the dissociation of steam into oxygen and hydrogen by thermal or chemical reactions, and the chemical reactions of dissolved oxygen in water. These gases must be extracted from the condenser for the following reasons:

- The presence of air / non-condensable gases either reduces the shell-side film heat transfer coefficient or, by completely blanketing tubes in certain regions of the tube bundle, reduces the heat transfer area
- These gases and other species in the air contaminate the steam cycle and can negatively affect the cycle chemistry control of the plant. Good cycle chemistry control relies at a fundamental level on the control of dissolved oxygen, carbon dioxide, and other contaminants for the optimization of the chemical treatment regimen (see Section 3.3).

Cycle chemistry guidelines in the form of Technical Guidance Documents (TGD) have been developed by IAPWS [1-8]. These TGD establish operating guidelines and limits including the optimum concentration of dissolved oxygen at various points in the thermal cycle (for the chosen cycle chemistry regime of a given system).

The vapor-liquid mixture leaving the turbine is condensed at low pressure. In well designed and maintained condensers, the pressure of the vapor is well below atmospheric pressure, approaching the saturation pressure of the operating fluid at the cooling water temperature.



As the operating pressure of the condenser is lowered (vacuum is increased), the enthalpy drop of the expanding steam in the turbine will also increase. This will increase the amount of available work from the turbine (electrical output). By lowering the condenser operating pressure, the following will occur:

- Increased turbine output.
- Increased plant efficiency.
- Reduced steam flow (for a given plant output).

Air in-leakage has a similar deleterious effect on condenser performance as tube fouling on the cooling water side.

The vacuum in the condenser encourages AIL. Thus, to keep the concentration of non-condensable gases as low as possible, the condenser system must be reasonably leak tight. Failure to prevent or remove the non-condensable gases may cause corrosion in the system, lower heat transfer properties, and/or increase plant heat rate due to the backpressure rise associated with a high AIL. As discussed in Section 3.3, it can also restrict achieving the optimum chemistry control.

Under normal conditions, the air-removal system is able to maintain the concentration of non-condensable gases at a level that does not affect the condenser performance. When AIL exceeds the exhauster capacity at the operating suction pressure, the back pressure will rise, which can negatively affect both heat rate and/or generation capacity. Excess AIL beyond the capacity of the air-removal system is a potential cause for a significant rise in backpressure.

### 3.3 Cycle Chemistries used in Conventional and Combined Cycle Plants

The purpose of this sub-section is not to provide complete details on feedwater and condensate chemistry for conventional and combined cycle / HRSG plants, as this is already published in previous IAPWS Technical Guidance Documents [1-8]. Included here is a quick “tour” of the chemistries available for conventional and combined cycle plants, the key points in relation to air in-leakage, and specific general guidance for condensate / feedwater oxygen levels which will be informative for the later sections of this TGD.

Most often a volatile alkalizing agent, usually ammonia, is added to the condensate / feedwater to increase the pH. Alternatively, an alkalizing amine, or a blend of an alkalizing amine with ammonia, can be added in place of ammonia. There are recent examples of film-forming substances (FFS) being used instead of the ammonia or alkalizing amine [8]. FFS include film-forming amines (FFA), film-forming amine products (FFAP), and film-forming products (FFP) that do not contain an amine.

Following are descriptions of the commonly used feedwater / condensate volatile treatments and FFS that can be applied to the condensate and feedwater in conventional plants, and to condensate, feedwater, and evaporator water in combined cycle / HRSG plants.

AVT(R) – All-volatile Treatment (Reducing). [3] This treatment involves the addition of ammonia, an amine, or a blend of amines of lower volatility than ammonia, along with a reducing agent (usually hydrazine or one of the acceptable substitutes such as carbohydrazide) to the condensate or feedwater of the plant. In combination with a relatively low oxygen level (required from air in-leakage) of about 10 ppb ( $\mu\text{g}/\text{kg}$ ) or less in the condensate (usually measured at the condensate pump discharge, CPD), the resulting feedwater will have a reducing redox potential (usually measured as Oxidation-Reduction Potential, ORP). Higher levels of oxygen ( $>20$  ppb ( $\mu\text{g}/\text{kg}$ )) (due

to high levels of air in-leakage) will usually preclude generation of the reducing environment, but are often incorrectly accompanied by excessive dosing of the reducing agent.

AVT(R) provides protection to copper-based alloys in mixed-metallurgy feedwater systems in conventional plants. However, key basic international guidance is that AVT(R) with a reducing agent should not be used in conventional plants with all-ferrous feedwater systems and in combined cycle / HRSG plants due to concerns for single-phase FAC.

**In the context of the current TGD, it must be made clear that a reducing agent cannot overcome (reduce) the effects (deterioration of condenser vacuum and thus plant efficiency, increase of CACE) that result from air in-leakage.**

AVT(O) – All-volatile Treatment (Oxidizing). [3] This all-volatile treatment is the preferred treatment for conventional plant feedwater systems that only contain all-ferrous materials (although copper alloys can be present in the condenser) and for combined cycle / HRSG plants. In these cases, a reducing agent should not be used during any operating or shutdown / layup period. Ammonia or an amine, or a blend of amines of lower volatility than ammonia, is added at the CPD or condensate polisher outlet (if a polisher is included within the cycle). This is the treatment of choice for multi-pressure combined cycle / HRSG plants which most often have no copper alloys in the feedwater circuits. In combined cycle / HRSG plants with relatively good control of air in-leakage (oxygen levels in the range 10–20 ppb ( $\mu\text{g}/\text{kg}$ )), the resulting feedwater will yield a mildly oxidizing ORP.

OT – Oxygenated Treatment. [3] For conventional plants, optimized OT involves one oxygen injection location at the condensate polisher outlet (CPO), operating with the vents on the feedwater heaters and deaerator closed. Ammonia is added at the condensate polisher outlet. There is often a minimum level of oxygen that is required to provide and maintain full passivation of the single-phase flow locations in the main feedwater line and the drain lines, and to maintain this protection. For drum units, this is usually between 30 and 50 ppb ( $\mu\text{g}/\text{kg}$ ) at the economizer inlet (with the actual level being set in accord with the boiler recirculation ratio), and for once-through / supercritical units this is usually 30–150 ppb ( $\mu\text{g}/\text{kg}$ ) at the economizer inlet. This is the feedwater of choice for conventional units with all-ferrous feedwater heaters and a condensate polisher and with an ability to maintain a conductivity after cation exchange (CACE) of  $< 0.15 \mu\text{S}/\text{cm}$  under all operating conditions. The use of OT is much rarer in combined cycle / HRSG plants, but can be used in cases where the passivation of single-phase flow locations is not optimized because of very good AIL control and an associated low level of oxygen in the feedwater and evaporators circuits.

FFS – Film Forming Substances. [8] These substances work in a different way from the conventional treatments by being adsorbed onto metal oxide / deposit surfaces, thus providing a physical barrier (hydrophobic film) between the water / steam and the surface. There are three main chemical substances which have been used historically: Octadecylamine (ODA), Oleylamine (OLA), and Oleylpropylenediamine (OLDA). As well as these compounds, the commercial products contain other substances such as: alkalizing amines, emulsifiers, reducing agents, and dispersants. Film forming products (FFP) are also used and these do not contain an amine. The cycle chemistry guidance for the plants remains the same as for the volatile treatments as well as including the requirements for air in-leakage and oxygen levels in the condensate / feedwater. However, the continuous degradation of a FFS (especially FFAP) and/or an alkalizing amine results in organic intermediates and carbon dioxide with a concomitant increase in CACE in the feedwater, steam, and condensate. This may rise above the AVT(O) limit of  $0.2 \mu\text{S}/\text{cm}$ . If so, this could impede the early identification of an AIL event by an increase in CACE levels because it occurs in addition to an existing high CACE level.

General Requirements and Guidance for Air in-leakage and Oxygen in the Condensate and Feedwater. The four previous sub-sections have indicated that air in-leakage should be controlled for all the volatile feedwater treatments with a general requirement for oxygen levels to be below 10 ppb ( $\mu\text{g}/\text{kg}$ ) in the condensate (at the condensate pump discharge). The reasons for this requirement in different types of plants with different system metallurgies will be discussed further in Sections 5.2 and 5.3. There are related limits for oxygen in waterwalls and HP evaporators for conventional and combined cycle / HRSG plants, respectively. In both cases, the IAPWS guidance is generally for the oxygen to be less than 10 ppb ( $\mu\text{g}/\text{kg}$ ) to prevent the onset and propagation / continuation of under-deposit corrosion mechanisms. This level is controlled by the recirculation ratio of the drum boiler (level of oxygen at the economizer inlet to the level of oxygen in the drum / downcomer). For drum units operating on OT [3], the IAPWS feedwater oxygen limit at the economizer inlet is typically in the range of 30–50 ppb ( $\mu\text{g}/\text{kg}$ ) to meet this requirement. On drum units, operating on OT or AVT, where AIL is out of control with high feedwater oxygen levels the same limit range should apply at the economizer inlet.

For Oxygenated Treatment (OT), AIL cannot be taken as a substitute for oxygen injection. The oxygen concentration after the condensate pump should be kept below 10 ppb ( $\mu\text{g}/\text{kg}$ ) in order to overcome (reduce) the effects (deterioration of condenser vacuum and thus plant efficiency, increase of CACE) as a result of air in-leakage. If higher oxygen concentrations in feedwater are desired, then oxygen has to be added downstream of the condensate pump.

### 3.4 Sources of Air In-leakage

The main sources of air in-leakage are:

- Low pressure steam turbine / condenser expansion joints.
- Low pressure steam turbine shaft seals.
- Low pressure steam turbine instrumentation lines.
- Steam turbine district heating heat exchanger in hot well.
- Low pressure feedwater heaters (including piping, drains, valves, etc.).
- High pressure feedwater heaters (emergency drains out of service).
- Condenser drains.
- Condensate pump seals.
- Turbine gland steam condenser.
- Condensate polisher (possibly when shut down).
- Makeup water lines if left open during operation.
- Vacuum breakers.
- Rupture disks.
- Safety valves.
- Condenser tube sheet to shell joints.
- Condenser wall cracks.
- Condenser instrumentation and connections (sight glasses, level transmitters, etc.).
- Air removal equipment suction components (such as steam jet air ejectors)
  - Condensate drain seals
  - Drains
  - Isolation valves
  - Flanged and threaded connections
  - Air jets
  - Shaft seals

- Deaerators operating at sub-atmospheric pressures.
- Orifice flanges, piping flanges.
- Valve stems.
- Condenser manway covers.
- At the suction side of boiler feedwater pumps (pump seals).
- Flash tanks, desuperheating tanks, and connections.

Locations of AIL for other equipment, such as air-cooled condensers (ACC), are included in Section 7.

### 3.5 Background Science on AIL

Basically, AIL can take place where the local pressure is below atmospheric. This includes places with water (e.g., condensate) or with steam (e.g., condenser shell side).

AIL into the water phase may be fully (e.g., AIL at condensate extraction pump seal) or partially (e.g., AIL into the hotwell where part of the air rises up into the condenser shell) into the condensate. If there is a deaerator, it will then be subject to the mechanisms governing AIL into the steam phase.

Consideration of the distribution equilibria of the main components of air into a wet steam phase is necessary to understand the mechanism of AIL.

- Nitrogen – the most abundant gas (~78 v/v% in dry air) – is chemically inert in relation to the water-steam circuit and thus only influences the vacuum conditions.
- Oxygen – the other major component of air (~21 v/v% in dry air) – plays a major role in the chemistry and conditioning of the water-steam circuit. Oxygen is usually monitored in feedwater and condensate.
- Argon – a minor component of air (~0.93 v/v%) – is chemically inert and behaves like nitrogen.
- Carbon dioxide – a minor component (~0.04 v/v%) – is the air component which raises CACE through the formation of carbonic acid and dissociation to the bicarbonate ionic form.

#### Nitrogen, Oxygen and Argon

The distribution of the three most abundant gases in air (nitrogen, oxygen, and argon) is governed by the equilibria between gaseous and aqueous species described by Henry's constant:<sup>1</sup>

$$k_H = p_i / c_i ,$$

in which  $c_i$  is some measure of concentration of the aqueous gas  $i$  (e.g., mol/kg) and  $p_i$  the partial pressure (e.g., in bar) of gas  $i$  in the gas mixture (steam) contacting the water phase. This means that the concentration of the dissolved gas is proportional to the partial pressure of the gas, which rises when AIL occurs. Henry's constant is temperature dependent, such that the value increases with temperature up to 75–105 °C, i.e., the solubility of the gases correspondingly decreases with

<sup>1</sup> This definition of Henry's constant here differs from that in the IAPWS Guideline on Henry's constant [9] in that it substitutes the more easily known partial pressure for the thermodynamic quantity fugacity. This approximation introduces only small errors for atmospheric gases in steam. Ref. [9] also uses mole fraction as the concentration unit; conversion to mol/kg or mol/L can be made using the molar mass of water, and in the case of mol/L the density of pure liquid water at the temperature of interest.

increasing temperature. Above 105 °C, the values of Henry's constant for nitrogen, oxygen, and argon decrease with temperature, i.e., the gases have minimum solubility in the range 75–105 °C. Table 1 summarizes values for Henry's constant versus temperature for the relevant gases.

**Table 1.** Values for Henry's constant at temperature,  $k_H = p_i/c_i$  [9]. Concentration units are either bar/(mol/kg) or bar/(mol/L). The first unit is conventionally used for values at temperature; the latter unit is compatible with the equilibrium constants for CO<sub>2</sub> in Table 2.

$k_H$ bar/(mol/kg)	$\log_{10}(k_H)$					
	25 °C	50 °C	75 °C	100 °C	125 °C	150 °C
N <sub>2</sub>	3.188	3.294	3.333	3.324	3.281	3.212
O <sub>2</sub>	2.896	3.027	3.089	3.101	3.076	3.025
Ar	2.854	2.983	3.047	3.063	3.043	2.998
CO <sub>2</sub>	1.475	1.708	1.863	1.961	2.016	2.039
$k_H$ bar/M	$\log_{10}(k_H)$					
	25 °C	50 °C	75 °C	100 °C	125 °C	150 °C
N <sub>2</sub>	3.189	3.299	3.344	3.343	3.308	3.250
O <sub>2</sub>	2.897	3.032	3.100	3.119	3.104	3.063
Ar	2.855	2.989	3.058	3.081	3.071	3.036
CO <sub>2</sub>	1.476	1.713	1.874	1.980	2.044	2.076

In wet steam, the liquid fraction of the steam/water mixture largely determines where the gases are present. From the rear end of the (low pressure) turbine towards the condenser, the steam contains some liquid water. However, the steam phase is dominating, and the majority of the soluble gases are present in the steam, even though the distribution fulfills the equilibrium. Further condensation takes place along the steam path through the condenser, and ideally is complete in the air removal section, where gases are removed by air ejection. In the final stages of condensation, the steam fraction has decreased, and the gas partial pressure has increased, and with it the concentration of dissolved gases in the liquid phase. Air ejection limits the gas partial pressure and thus reduces the driving force for gas dissolution. Overall, the majority of the gases is removed by the air ejection system, but some goes into the condensate. The fraction in the condensate depends on the distribution equilibria; the smaller the Henry's constant, the larger the concentration in the condensate and the less the effectiveness of deaeration. Condensation and gas dissolution are, however, dynamic events and attaining near-equilibrium conditions is the goal of appropriate component design.

From a practical point of view, this behavior may give a hint to the location of AIL. Oxygen is often monitored continuously in the condensate or may easily be measured by a mobile instrument. If the AIL occurs where the steam phase is dominant, i.e., upstream of condensation, the intruding gases will mainly be present in the gas phase. Thus, it is very likely that the evacuation system in the main condenser will remove most of the gases such that only relatively small amounts are present during the condensation process, ending up in the condensate. If, on the other hand, the AIL appears downstream of condensation, where the liquid phase is dominant, such as in the hotwell or in the condensate system, the gases will mainly be present in the liquid phase and give relatively high concentrations in the condensate. This behavior explains why AIL does not necessarily lead to increased dissolved oxygen concentrations in the condensate.

When the condensation process is complete, and the pressure is increased by the condensate extraction pumps, the gases from AIL will be present as dissolved species. This may change

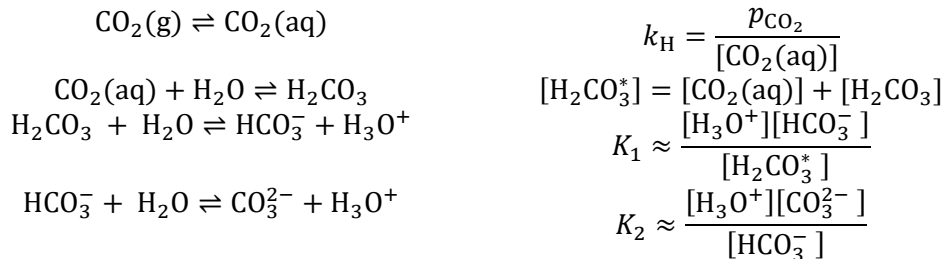
throughout the condensate train when the temperature increases and the value of Henry's constant increases. This will push the distribution equilibria towards the gas phase, and this change is the principle governing the removal of dissolved gases in the deaerator.

If the gases enter the boiler due to insufficient or no deaeration of the feedwater, they will exit with the steam in all boiler systems and are now conventionally referred to as non-condensable gases. Such gases may influence the efficiency of the LP feedwater heaters (if present) because the non-condensable gases will reduce the partial pressure of steam in the heaters. This means that condensation will take place at lower temperature, thus reducing the heat transfer to the condensate and increasing the terminal temperature difference (TTD) observed for the feedwater heaters. This is especially the case for plants operating on OT with no venting of the feedwater heaters (in order to maintain oxygen in the preheater condensate).

To conclude, nitrogen, oxygen, and argon stay mostly in the gas phase and are removed by deaeration. If they accumulate they may hamper condensation, causing a loss in plant efficiency. In addition, oxygen in the aqueous phase may jeopardize the specifications for condensate and feedwater. It also serves as an ambiguous indicator for AIL.

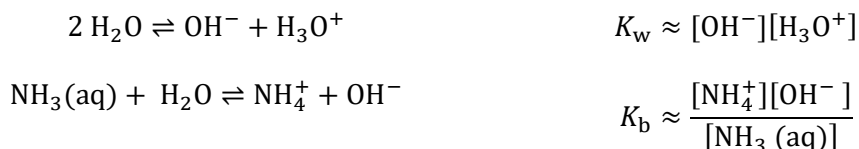
### Carbon Dioxide

For carbon dioxide, the value of Henry's constant is smaller, and hence the solubility is considerably higher, than for the other gases, and the maximum in  $k_H$  (minimum solubility) is at a higher temperature, near 160 °C. The situation regarding its solubility is however more complex due to the reaction of the dissolved gas forming carbonic acid and the associated acid/base equilibria. Carbon dioxide will still be present as dissolved gas in the water according to the Henry constant, but at the same time there will be some more dissolved in the ionized forms  $\text{HCO}_3^-$  and  $\text{CO}_3^{2-}$ . That means more  $\text{CO}_2$  is absorbed in order to form the dissociated species.



Since  $[\text{CO}_2(\text{aq})] \gg [\text{H}_2\text{CO}_3]$ , the sum of the two is conventionally approximated as  $[\text{H}_2\text{CO}_3^*] \approx p_{\text{CO}_2} / k_H$ .

The presence of an alkalizing agent, such as ammonia, makes the situation even more complex, as it reacts with the carbonic acid and hydrogen carbonate and pulls the equilibria towards the hydrogen carbonate and carbonate species, respectively. That means even more  $\text{CO}_2$  is absorbed in order to form the ionized species.



The ionization constants used for the following considerations are listed in Table 2.

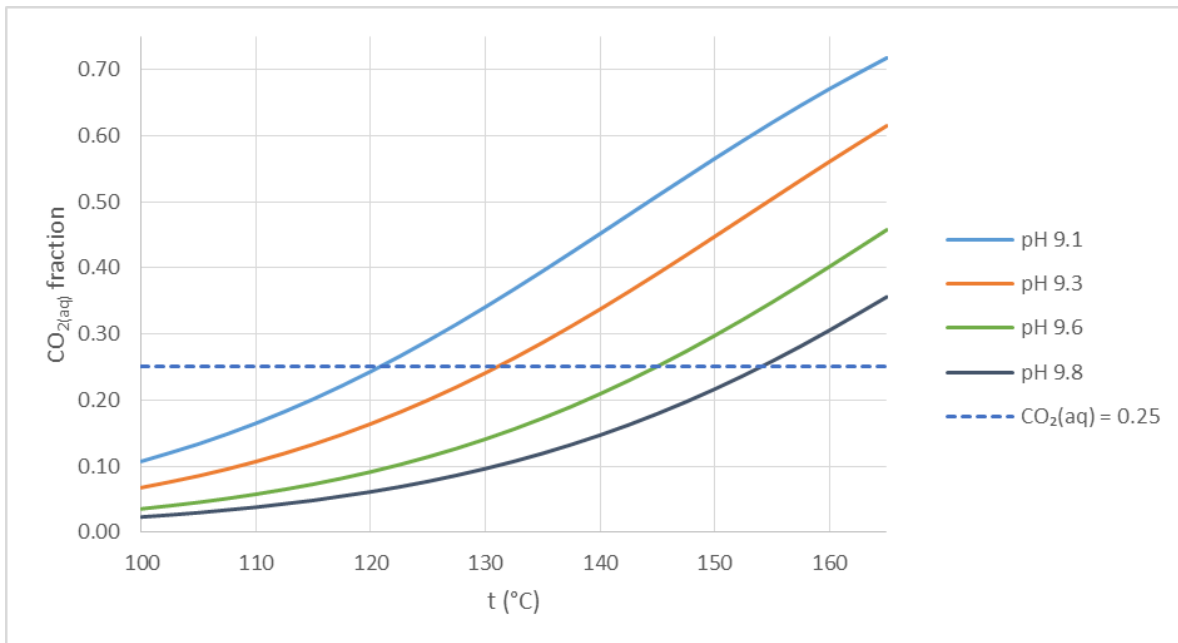
**Table 2.** Ionization constants [10,11]

Constant, $K_x$	Unit	$\log_{10}(K_x)$					
		25 °C	50 °C	75 °C	100 °C	125 °C	150 °C
CO <sub>2</sub> $K_1$	M	-6.345	-6.269	-6.293	-6.388	-6.535	-6.724
CO <sub>2</sub> $K_2$	M	-10.329	-10.169	-10.095	-10.084	-10.121	-10.200
NH <sub>3</sub> $K_b$	M	-4.754	-4.733	-4.772	-4.854	-4.970	-5.115
H <sub>2</sub> O $K_w$	M <sup>2</sup>	-13.995	-13.265	-12.696	-12.252	-11.906	-11.641

The relatively high solubility of CO<sub>2</sub> and the additional formation of dissociated species mean that the liquid phase will absorb carbon dioxide significantly even though the partial pressure is low, and, consequently, carbon dioxide goes in the liquid phase as carbonates even at relatively low liquid fractions during condensation. Thus, carbon dioxide will partially end up in the condensate, and this to a higher degree than nitrogen, oxygen, and argon.

Consideration of the equilibria above shows that the fraction of CO<sub>2</sub> present as the aqueous species varies with pH and temperature of the deaeration device (e.g., condenser, deaerator). It is only the aqueous species that may be removed by deaeration. Both the solubility as well as the dissociation of CO<sub>2</sub> decrease with temperature. In effect, there will then be less CO<sub>2</sub> in the aqueous phase at higher temperature. Deaeration of CO<sub>2</sub> is therefore more efficiently done at elevated temperature, e.g., in the deaerator.

Figure 1 shows the relationship between the fraction present as dissolved carbon dioxide and temperature at typical pH values (given at 25 °C, i.e., the setpoint for pH of the feedwater). Experience shows that deaeration of CO<sub>2</sub> is practically possible when around 25% of CO<sub>2</sub> is in the aqueous form. It is seen that efficient deaeration requires an elevated temperature.

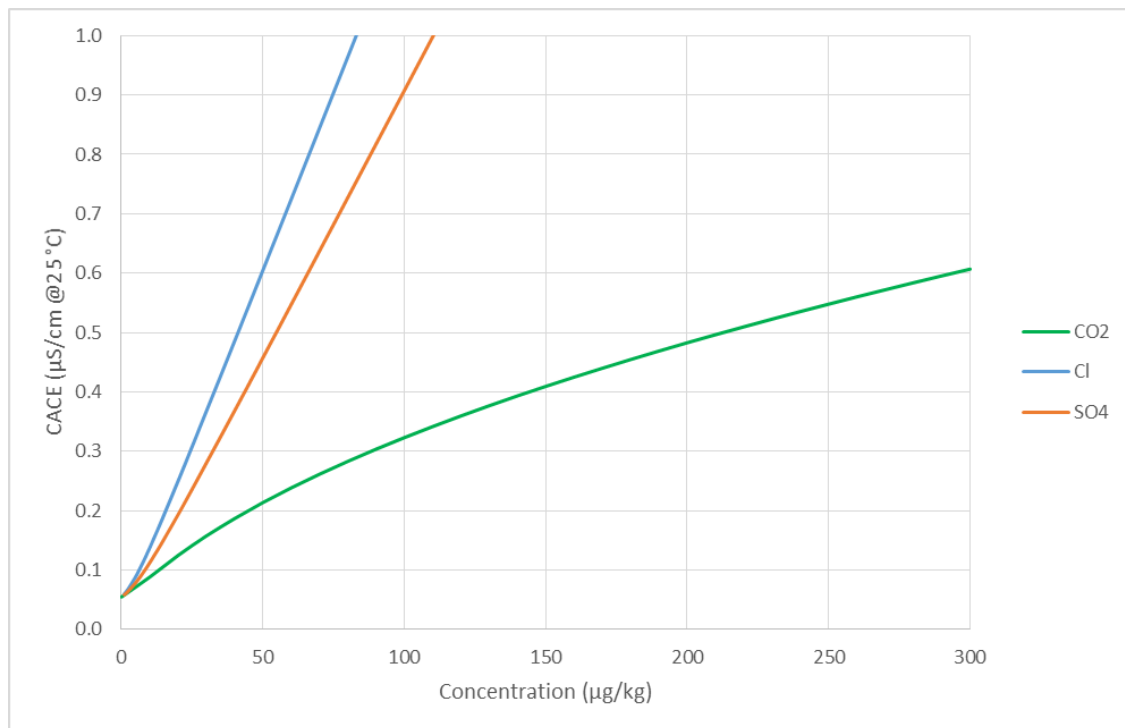


**Figure 1. Fraction of CO<sub>2</sub> Present as the Aqueous Species Dependent on Temperature and Feedwater pH (alkalizing with NH<sub>3</sub>).** (Note that level of 25% present as aqueous CO<sub>2</sub> is reached at ~120 °C at pH 9.1, at ~130 °C at pH 9.3, at ~145 °C at pH 9.6, and at ~155 °C at pH 9.8).

Different from nitrogen and oxygen,  $\text{CO}_2$  – due to its very low fraction in air – hardly causes any gas accumulation that hampers proper condensation and reduces plant efficiency. The hydrogen carbonate and carbonate, however, will cause an increase in CACE.

The international experience of IAPWS is that a CACE value up to  $0.4 \mu\text{S}/\text{cm}$  due to carbon dioxide from AIL is common, CACE up to  $0.6 \mu\text{S}/\text{cm}$  may occur, but CACE above this level from this source is rarely seen. In that case, more hazardous species such as chloride and sulfate should be suspected as the source of an increased CACE observed. Figure 2 displays CACE versus concentration for the three mentioned contaminants.

In many cases the vent of the deaerator goes back to the condenser, where  $\text{CO}_2$  is only poorly removed. This results in a situation where more  $\text{CO}_2$  will be present in the condensate, feedwater, and steam, resulting in an elevated CACE. The elevation of CACE will be larger in case of high feedwater pH, and will be lower in plants where the deaerator vent is not recycled back to the condenser. An analogous argument is valid for the steam ejectors commonly used for condenser evacuation. If the condensate from the steam ejector is led to the hotwell, gaseous  $\text{CO}_2$  removed by evacuation and now dissolved in the condensate is recycled into the water/steam circuit.



**Figure 2. CACE versus Concentration for Selected Contaminants.**

The curve for carbon dioxide in Fig. 2 may be used to estimate the size of the AIL if carbon dioxide is the only source of increased CACE. In that case, the concentration of carbon dioxide is read from the curve and converted to an AIL flow knowing the feedwater or condensate flow and the content of carbon dioxide in air. Complete uptake of carbon dioxide in the condensate may be assumed for this estimation.



It is important to note that air in-leakage may often occur without clearly visible indicators in the cycle chemistry (e.g., by increased dissolved oxygen concentrations). CACE, especially in the condensate, is usually the most sensitive indicator of an AIL. However, CACE is non-specific and may also be caused by other contaminants. Some treatment schemes, e.g., with film-forming substances (FFS), lead to increased levels of CACE due to the thermal decomposition of these FFS (especially when using a FFAP). In that case, the contribution to condensate CACE from AIL may be masked by the levels normally measured.

## 4. Locating and Measuring Air In-leakage

### 4.1. Instrument-based or Non-Chemistry Techniques

Air-in-leakage may be detected by observing the measured values of pressure, temperature, and CACE on a routine basis. Indications of AIL are summarized in Table 3.

**Table 3.** Operational Observations of AIL

<b>Indicator</b>	<b>Remark</b>
Vacuum in main condenser	Observe vacuum in main condenser vs. cooling water temperature at high load condition. Observe TTD. Compare with reference data.
Load on vacuum pumps	Observe number of vacuum pumps and/or load – higher numbers than usual indicate difficulties keeping the vacuum. Air flow can be measured.
Pressure buildup/venting frequency of LP feedwater heaters	Plants on OT running with LP feedwater heater vents closed may need to open the vents regularly to remove non-condensable gases. Frequent need to do this / faster pressure rise / higher TTD indicate presence of non-condensable gases from AIL.
Deaeration for plants	Starting deaeration of feedwater will gradually remove non-condensable gases. This will improve the indicators mentioned above. If the plant operates the deaerator above 135 °C with pH less than 9.4, a gradual decrease in CACE will also be observed due to deaeration of carbon dioxide.
Vacuum fall test	When AIL is suspected, a vacuum fall test may confirm it. See Section 4.2 for further information.
CACE in main condensate, boiler water, and superheated steam	CACE often will be increased in the main condensate by the ingress of CO <sub>2</sub> and the consequent formation of bicarbonates. Typically, and in comparison with salt ingress, there is no or very little effect on the CACE of boiler water, meanwhile in parallel CACE in superheated steam will reach a level close to CACE in main condensate.

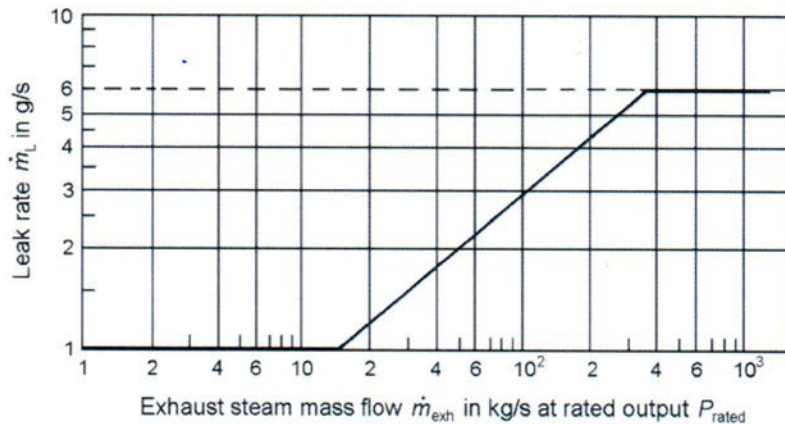
The vacuum in the main condenser at a given high load condition and the corresponding TTD under normal, undisturbed conditions should be observed regularly to form a reference data set. Subsequent observation of these values under reference conditions will indicate possible AIL. A change in TTD may also be caused by fouling of the condenser on the cooling water side, but the vacuum will not be influenced in this case.

The vacuum fall test is the ultimate test for AIL. This test is performed at high load conditions also, e.g., corresponding to the regular observation of vacuum and TTD. The procedure is summarized in the next sub-section.

#### 4.2. Vacuum Fall Test (alternatively called either Vacuum Drop Test or Vacuum Decay Test)

This test involves monitoring the decay of the vacuum in the condenser when the vacuum pumps are turned off. The following definitions and values are applicable.

- Leak rate  
The leak rate  $\dot{m}_L$  is the amount of air, expressed in g, leaking into the condenser in a given unit of time (s).
- Permissible leak rate  
Non-condensable gases are removed from the condenser by the vacuum pumps. The actual leak rate must not exceed the design basis leak rate of the vacuum pumps/ejectors.



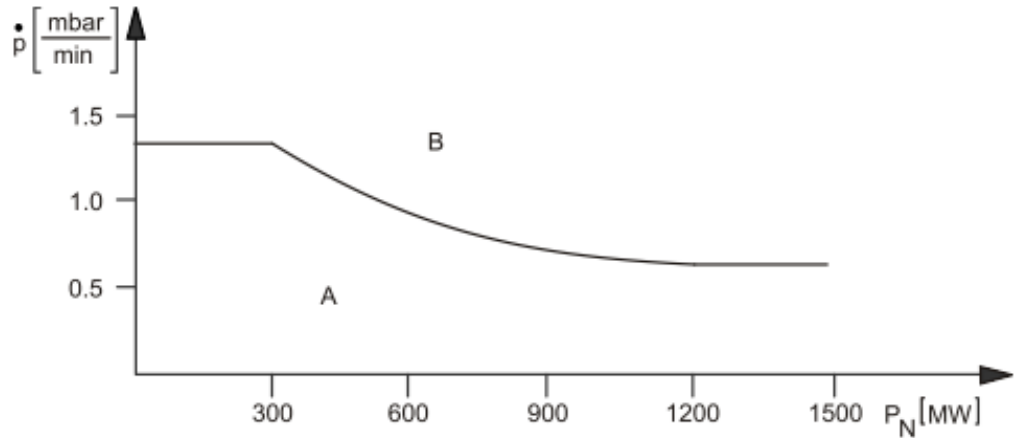
**Figure 3. Leak Rate for the Design of the Vacuum Pumps [12]**

Figure 3 [12] shows the design basis leak rate for vacuum pumps as a function of exhaust steam mass flow at rated output. The exhaust steam mass flow for the specific plant is to be taken from the associated heat balance diagram.

The results of the vacuum decay test for the same leak size vary with the effective volume of the condensation area. Consequently, there is no generic guidance value available. The volume of the evacuated area is only one of the factors influencing vacuum decay. For a vessel under vacuum, based on the ideal gas law, the rate of vacuum decay is proportional to air in-leakage flow rate and inversely proportional to volume at a given temperature and gas properties. However, steam condensation takes place in a condenser; the effectiveness of this is reduced by air in-leakage which increases the condenser pressure. Consequently, during the vacuum drop test there will also be

vacuum deterioration due to this secondary effect of air in-leakage. The extent of this depends on the condenser design and the location of the air leaks. This double effect of air in-leakage into the condenser is the reason why it is not possible to set exact general guidance values for allowable vacuum decay for operational vacuum drop tests.

However, based on experiences for water-cooled condensers the curve of Figure 4 may be used as guidance [13].



**Figure 4: Orientation Values for Water-cooled Condenser for Vacuum Decay at Nominal Load [13]**

Area A: Leak rate normal; Area B: Leak rate too high

#### Rate of condenser pressure change

The rate of condenser pressure change  $\dot{p}$  is the change in condenser pressure  $\Delta p_c$  in mbar or mm Hg that takes place during a given unit of time  $\Delta t$  (min) if gases leaking into the condensing plant are not extracted. The rate of condenser pressure change,  $\dot{p}_c = \frac{\Delta p}{\Delta t}$  in mbar/min or in mm Hg/min, is determined by the leakage test.

#### Performance of the Leakage Test

- Turbine generator load:  
The turbine generator load during a leakage test of each condenser must correspond to the load in force when the correlation between the rate of condenser pressure change and the leak rate was obtained during initial startup.
- Measurement of condenser pressure:  
During a leakage test, the condenser pressure  $p(t_0)$  at the beginning of the test duration ( $t_0$ ) and  $p(t_1)$  at the end of the test duration ( $t_1$ ) has to be measured with an accurate, prompt response pressure instrument. Indication range and scale division of the pressure display must allow condenser pressure to be read off with adequate accuracy. On-line performance monitoring for the condenser pressure measurement must be absolute, i.e., not relative to atmospheric pressure. The accuracy must allow pressure differences to be resolved down to 1 mbar or better, and in the vacuum fall test, a fast response is essential.

- Measurement of test duration:  
A stop watch should be used for measuring the test duration  $t_0$  to  $t_1$ .
- Test duration:  
The test duration should be 10 minutes.

It is advisable to stop testing if the rate of condenser pressure change is so high that it could cause turbine trip initiation by the condenser protection system. The leak rate must then be reduced by locating and repairing the air leaks before the leakage test is repeated.

### 4.3 Online Cycle Chemistry Monitoring in Relation to AIL

The assessment of the on-line chemistry instruments for identifying AIL or other contamination depends on the plant type and configuration exemplified here by:

- Drum type/combined cycle/HRSB boilers without ion-exchange-based condensate polishing plant (CPP). In this case, carbon dioxide in the condensate passes the condensate train and reaches the deaerator feedwater tank where it may be partially removed by degassing. Oxygen and the other non-condensable gases go with the condensate to the deaerator/feedwater tank where they will be removed by degassing (AVT conditioning assumed).
- Once-through boilers with full flow condensate polishing. Here, the carbon dioxide in the condensate will be removed by the CPP, such that the conductivity at the CPP outlet is typically less than  $0.1 \mu\text{S}/\text{cm}$ . This is helpful in locating the entry point of AIL or another contamination because the entry point may roughly be identified from the CACE increments noted for the measurements along the flow path towards the boiler (e.g., downstream CPD, CPP, LP heaters, deaerator/feedwater tank, and upstream of economizer). Oxygen and other gases pass the CPP and continue to the deaerator/feedwater tank. Here, they are removed by degassing, if the plant is running on AVT. A once-through boiler will most often be on OT; in this case, all the venting from the deaerator should be closed, and the gases continue through the feedwater tank towards the boiler and end up in the steam.

Furthermore, conditioning of the feedwater influences the assessment and the possibility to properly identify a contamination as AIL. The conditioning schemes for AVT, OT, and FFS were introduced in Section 3.3.

The observation of an increased CACE on the on-line monitors is usually the starting point of identifying AIL. However, carbon dioxide from AIL is only one of several contaminants that lead to increased CACE in the water-steam system, but fast and reliable evaluation of the source of increased CACE determines the follow-up actions to be taken. This is covered in detail in the IAPWS Steam Purity TGD [5]. The cause may be harmless, such as an exhausted cation resin in the sample filter at the sample point exhibiting increased CACE. If not, then it is important to distinguish among the possible sources:

- Air In-Leakage. With respect to corrosion, this is usually relatively harmless and does not present a threat to the materials of the boiler and turbine. However, as discussed in Section 3.2 there is the possibility of harmful ions such as  $\text{Cl}/\text{SO}_4/\text{NO}_3$  entering plants sited in air-polluted industrial areas. Also, as mentioned in Section 5, AIL presents other disadvantages for the operation of the plant.

- **Organics.** This includes organic matter of extraneous origin such as oil, grease, additives to secondary circuits, and humic substances from makeup water production. In passing through the boiler, this organic matter breaks down to smaller molecules. They are finally mineralized to carbon dioxide, water, and the mineral acids corresponding to the contents of N, S, P, and possibly Cl. Small chain carboxylic acids, such as formic and acetic acids, are typical intermediates on the route of mineralization, and these species are routinely used as tracers for this type of contamination. Organic additives to the main circuit also produce CO<sub>2</sub> and organic acids such as acetate, formate, etc. A contamination with organics always presents a deviation from optimal chemistry. The source should be identified, and the situation corrected as soon as possible. Depending on the specific type of organics and content of elements that mineralize to strong acids, the contamination may present a corrosion risk. Intermediate compounds such as formic and acetic acids are considered relatively harmless with respect to corrosion, as long as they are present in molar amounts that are small compared to the concentration of the alkalinizing agent, in which case they will not affect pH. This holds true with the exception of the phase transition zone (PTZ), where the concentrations and distribution coefficients of the species in the steam influence the pH of the early condensate. For example, in plants using ammonia only, it will remain in the steam phase whereas formic and acetic acids dissolve in the first water droplets spontaneously. As a consequence, the pH of the early condensate might be as low as 4.0. However, where plants use certain blends of alkalinizing amines of very low volatility (low partitioning coefficient), such as ethanolamine and/or ethanolamine/ammonia, the pH of the early condensate will be very close to the guidance range proposed by IAPWS.
- **Salts and acids.** These are the most hazardous contamination types, and the integrity of the components of the water-steam circuit may be put at risk by a massive contamination such as from a leaking condenser. Even at a lower level, this type of contaminant promotes corrosion, under-deposit corrosion, and stress corrosion cracking: IAPWS suggests a shutdown criterion for CACE in the feedwater which exceeds 2 μS/cm for two minutes and is increasing [3].

The sample points and measured parameters relevant to identify the source of increased CACE are summarized (and marked with X) in Table 4. In accordance with the IAPWS TGD for minimum key instruments [2], the measurement of CACE and dissolved oxygen (DO) in condensates (main condensate, return condensate from district heaters, process return condensate, etc.) are key parameters and also most useful as diagnostic parameters. If not permanently installed, the measurement of DO, DCACE, and Na may conveniently be performed by mobile instrumentation at site as followup when increased CACE or other indicators show a chemistry excursion or AIL.

**Table 4. Sample Points and Parameters**

<b>Sample point: Parameter</b>	<b>Feed- water</b>	<b>Boiler water / Separation Bottle*</b>	<b>Sat. Steam</b>	<b>Main Steam</b>	<b>Conden- sate(s)</b>
<b>C</b>		X			
<b>CACE</b>	X	X	X (drum only)	X	X
<b>DO</b>	X				X
<b>DCACE</b>	X			X	X
<b>Na</b>	X			X	X

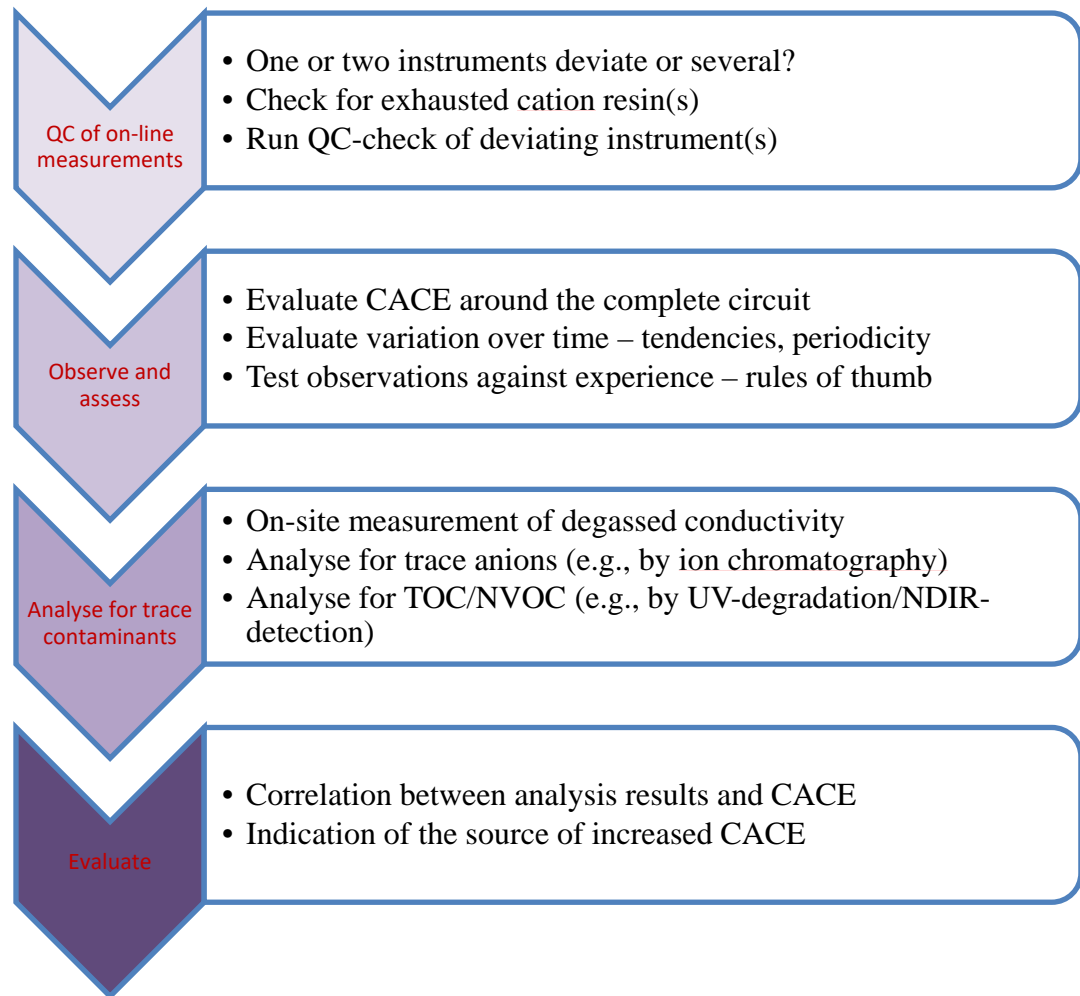
Shaded cells mark the measurements mentioned as minimum key measurements in the IAPWS TGD on Instrumentation [2]

Condensate(s) include main condensate, district heating condensate, process return condensate, etc.

\*CACE measured at a separation bottle for a once-through boiler operating below the Benson point (i.e., below the point of full feedwater evaporation)

Besides the online or onsite measurements mentioned above, analyses of grab samples for trace levels of anions (fluoride, acetate, formate, chloride, nitrate, sulfate, phosphate, etc.) by ion chromatography and organics as NVOC (Non-Volatile Organic Carbon, e.g., by UV-degradation and NDIR detection) are well-proven means to track down the source of a contamination causing increased CACE.

The procedure for evaluation of an increased CACE is summarized in Figure 5.



**Figure 5. General Procedure for Evaluation of CACE Excursions.**

Appendices A-E summarize "rules of thumb" regarding levels of, and relationship between, the on-line or on-site measurements that allow for the determination of the most likely source of the contamination for the Base Cases delineated in Section 6.1. Appendix F provides the same information for plant using a FFS. The appendices cover the combination of plant type, condensate polishing, and conditioning schemes shown in Table 5. Other combinations may be evaluated by analogy, e.g., by going through the common table of the appendices for the specific plant.

**Table 5.** Combinations of Plant Type and Feedwater Conditioning Considered in Appendices A-F

<b>Plant type: Conditioning scheme</b>	<b>Once-through boiler with full flow CPP</b>	<b>Drum A: with CPP B: without CPP</b>	<b>CC/HRSG Base Case d)</b>	<b>CC/HRSG Base Case e)</b>
AVT	Appendix C1	Appendix A: AVT(O) Appendix B: AVT(R)	Appendix D	Appendix E
OT	Appendix C2			
FFS/AVT		Appendix F		

#### 4.4 Tracer-based Method – He Gas Detection Procedure

The use of the tracer gas technique is the most consistently reliable method to detect the source of most air in-leakages with the unit online.

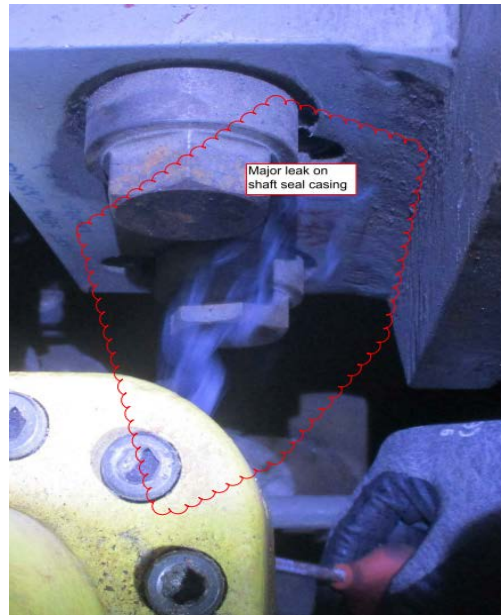
A tracer gas monitor is installed in the exhaust line (sometimes called air withdrawal line or off-gas line) from the air removal system, and the technician utilizing a handheld tracer gas dispenser walks around the unit in a methodical manner until the technician at the monitor observes a response. A portable monitor can also be used that allows one-person operation; the technician spraying the tracer gas also can check the readout, which can have advantages over attempting to decipher signals via remote communications.

The leak detection survey starts at the turbine deck level and proceeds from top to bottom of the unit, one deck at a time. Care must be taken when dispensing the tracer gas so that only one potential source is sprayed at a time; otherwise, the ability to associate a response with a specific source may become impaired.

Procedure for He gas detection: gas sensor in vacuum pump eject gives signal when the detection gas is blown at the leakage and thus sucked into the system. However, this procedure / equipment has some limitations as to what type of plants it can be applied. Many plant operators do not use it at plants with a back-pressure steam turbine due to the risk of water coming into the equipment.

#### 4.5 Smoke Detection Procedure

Procedure for smoke detection where artificial non-corrosive smoke is sucked with the air into the air in-leakage. This may be seen through the flow patterns in the vicinity visualized by the smoke as illustrated in Figure 6.



**Figure 6. Artificial Smoke being used to Detect AIL**

#### **4.6 Water Ingress Procedure**

One common source of air in-leakage, LP steam turbine rupture disks, can be identified by adding a thin layer of demineralized water to the top of the disk. If the water is rapidly drawn into the turbine, the rupture disk has a leak.

### **5. Impact of AIL on Power Plant Thermal Performance and Cycle Chemistry**

#### **5.1 The Need to Control AIL**

Condensers are designed with air extraction systems to process a given amount of AIL and maintain the unit performance at peak efficiency. This low *design* AIL is unavoidable and is always present. However, excessive AIL above this low design value will increase the concentration of non-condensable gases in the shell side of the condenser and lead to an increase in the thermal resistance to heat transfer. This will result in an increase in turbine backpressure and a higher unit heat rate. In some extreme cases AIL may even rise to the point where the turbine backpressure approaches its operating limit, forcing a reduction in load. Thus, the thermal efficiency of the condenser is adversely affected whenever there is a leak that exceeds the capability rating of the air extraction system. That means, even in plants operating with OT, the oxygen requirement for condensate and feedwater must be met, and it may be necessary to add oxygen after the condensate pump. AIL is not a valid substitute for achieving OT in the feedwater.

Another negative associated with high AIL is often an increase in the concentration of dissolved oxygen and CO<sub>2</sub> in the condensate and feedwater, a concentration that will tend to increase with lower condensate temperatures. The negative consequences are increased corrosion of any copper alloy feedwater heaters, especially in the LP feedwater system, as well as excessive buildup of deposits in boiler waterwall / HRSG evaporator tubes. This is discussed in the next subsections.



## 5.2 Plants with All-ferrous Metallurgy Operating on AVT(O) or OT

It is often thought by plant operators and other personnel that controlling air in-leakage is of minor importance for these plant feedwater and condensate systems because they already are operating under oxidizing conditions. This, of course, is totally incorrect as outlined in the following two subsections.

### Conventional Plants

The guidance for oxygen at the condensate pump discharge (CPD) was discussed in Section 3.3. Air in-leakage needs to be controlled to maintain this guidance. If the AIL is well maintained, as indicated in other sections in this TGD, then the oxygen levels in the condensate and feedwater for all-ferrous plants should easily be within the 10 ppb ( $\mu\text{g}/\text{kg}$ ) IAPWS guidance at the CPD. For drum units operating on OT, this means that the optimum treatment can be achieved with the vents closed on the deaerator and feedwater heaters (LP and HP). This will ensure that the oxygen levels, achieved by oxygen injection after the condensate pump, are under control to meet the guidance of 30–50 ppb ( $\mu\text{g}/\text{kg}$ ) at the economizer inlet. The boiler water requirement of  $< 10$  ppb ( $\mu\text{g}/\text{kg}$ ) (drum / downcomer) will then not be exceeded. This all depends on controlling the air in-leakage. Although there is no similar boiler water oxygen requirement for once-through units (sub-, super-, and ultra-supercritical), it is equally important to control the air in-leakage in the condensate to ensure the deaerator and feedwater heater (LP and HP) vents can be closed to minimize the total iron levels in the drain lines and at the economizer inlet. Whether the vents need to be opened or closed during operation is determined by a monitoring campaign which also includes total iron.

### Combined Cycle / HRSG Plants

The first of the three basic rules for the chemistry of combined cycle plants is to ensure that the feedwater (economizers and preheaters) and LP/IP evaporators operate under oxidizing conditions to preclude the possibility of single-phase FAC in these circuits. This means that the air in-leakage must be controlled with oxygen levels at the CPD below 10 ppb ( $\mu\text{g}/\text{kg}$ ) and that no reducing agent is added to the condensate or feedwater. Very often in HRSGs with independently fed LP, IP, and HP circuits from the condensate, controlling the air in-leakage will also ensure that the HP evaporator can meet the requirement of  $< 10$  ppb ( $\mu\text{g}/\text{kg}$ ) in the drum / downcomer and thus lessen the risk of under-deposit corrosion in situations when contamination (condenser leak) occurs.

## 5.3 Conventional Plants with Mixed-Metallurgy Feedwater Systems Operating on AVT(R)

The guidance for oxygen at the condensate pump discharge (CPD) was discussed in Section 3.3. For fossil plants with mixed-metallurgy feedwater systems (copper alloys in the LP and/or HP feedwater heaters), the requirement to operate the feedwater under reducing conditions is of paramount importance. This can only be achieved by controlling air in-leakage as discussed in other sections of this TGD, so that the oxygen levels at the CPD are below 10 ppb ( $\mu\text{g}/\text{kg}$ ), together with the addition of a reducing agent in the condensate. The reducing environment encourages the formation of cuprous oxide on the copper alloy feedwater heaters; this is the more stable oxide of copper, whereas an oxidizing environment results in cupric oxide which is more porous and less protective. The formation of cupric oxide and its transport to the boiler and into steam is the start of a complex chain of chemical processes that can lead to copper deposits in the steam turbine and boiler waterwalls [14]. It is now well understood that operating plant with AIL levels out of control, or even elevated, so that condensate oxygen levels are considerably above 10 ppb ( $\mu\text{g}/\text{kg}$ ), means that a reducing environment cannot be maintained by increasing the addition of the reducing agent.

As per previous comments in this TGD, the basic requirement for plant operators is to maintain the AIL through a plant Air In-leakage Program (Section 6.2).

## 6. Guidance to Control Air In-leakage

One of the two distinguishing features of IAPWS TGDs is that each provides information and guidance for a number of base cases, which represent the predominant plants worldwide, and a road map section through which personnel from any plant worldwide can customize that information to their particular plant. The current TGD follows the same approach and this section defines the base cases from the plant equipment, cycle chemistry, performance aspects, and the main guidance for an air in-leakage team (Section 6.2). The customization aspects are included in Section 7.

### 6.1 Base Cases for Plant Equipment and Cycle Chemistry

The base cases for this TGD cover the most common conventional and combined cycle units and cycle chemistries in use around the world, and are the same as used for the Volatile Treatment TGD [3]. The major variations to these base cases are included in Section 7. The operator or chemist should determine which variation(s) to use and then customize to the plant. The Base Cases include the following:

- a) Conventional plants with drum units, all-ferrous feedwater systems, no reducing agent, non-copper tubed condensers, with a condensate polisher, and not cooled by seawater or brackish water.
- b) Conventional plants with drum units, mixed-metallurgy feedwater systems, copper tubed condensers, without a condensate polisher, and not cooled by seawater or brackish water.
- c) Conventional plants with once-through sub-, super-, and ultra-supercritical units, all-ferrous feedwater systems, non-copper tubed condensers, with a condensate polisher, and not cooled by seawater or brackish water.
- d) Multi-pressure combined cycle/HRSG drum units, no copper alloys, independently fed LP, IP, and HP circuits, no condensate polisher for AVT(O), no reducing agent added to the cycle, and not cooled by seawater or brackish water. The drum pressures on this base case are considered to be LP 0.5 MPa (70 psi), IP 2.4 MPa (350 psi), and HP 14 MPa (2000 psi).
- e) Multi-pressure combined cycle/HRSG drum units, no copper alloys, with the LP drum feeding the IP and HP circuits, no condensate polisher for AVT(O), no reducing agent added to the cycle, and not cooled by seawater or brackish water. The drum pressures on this base case are considered to be LP 0.5 MPa (70 psi), IP 2.4 MPa (350 psi), and HP 14 MPa (2000 psi).

It should be noted that none of these base cases includes air cooling (either an air-cooled condenser (ACC) or a Heller system). Such units are included as customizations in Section 7.

Appendices A-F include some of the key distinguishing cycle chemistry parameter indications for air in-leakage, organics in the cycle, and salt/acid contamination. Table 5 provides an overview of these combinations of plant type and chemistry conditioning.

### 6.2 Air In-leakage Control and Supervision

The importance of AIL for the different plants as outlined in Sections 3.3, 5.2, and 5.3 should provide an indication to the plant management that a multi-disciplinary team is actively engaged in

identifying and rectifying any AIL problem in the plant. It is never satisfactory to allow elevated AIL in a plant. The following provides an outline of the membership and responsibilities of the Air In-leakage Program Team in relation to the base case plants:

- Unit Operators. Checking at least every shift on the instruments provided for their unit: vacuum, air extraction, etc. Informing Team if there is a problem and asking chemists to confirm oxygen levels at CPD. Many plants monitor vacuum continuously, and have limits and an alarm.
- Plant Chemists or personnel responsible for plant chemistry. At least monitoring dissolved oxygen at the CPD on a daily basis. This should be < 10 ppb ( $\mu\text{g}/\text{kg}$ ) even for units on OT, as well as observing closely the values for CACE. Informing Team if oxygen and/or CACE is elevated/out-of-specification. This may correspond with the operators' monitoring, but as Section 3.5 has indicated there is not always a one-to-one agreement.
- Performance Group / Plant Engineer. Can identify if performance has been degraded.
- Maintenance and/or Inspection Group. Using tools delineated in Section 4 to identify location of AIL. This may require an outside testing organization, but many plants now have the equipment to conduct these inspections in house.
- Maintenance Group. Repair leakage as soon as possible.

As an example, whenever there is an indication of a possible AIL, the team is informed, and the members take action within their field of expertise following a procedure such as:

- Identify that the excursion is an AIL event. This includes use and assessment of the instrument-based techniques (Section 4.1 and 4.2) as well as the on-line chemistry based techniques (Section 4.3). Review of Appendices A-F will help in defining the source of the excursion. In the case that AIL is **not** the cause of the excursion, it is of high importance to identify the source of contamination and increased CACE and to take action accordingly.
- Identify the likely location of the AIL and then initiate a systematic search for the precise position of the leak (Sections 4.4 and 4.5). Any leaks identified and labeled during a previous AIL inspection should be checked to confirm that the in-leakage was addressed effectively.
- Repair the leak promptly, or at the next convenient opportunity, if an outage is required.
- Test that the AIL has been resolved by the instrument and on-line chemistry based techniques.

## 7. Customization of the Air In-leakage Approach and Guidance for Plants, Equipment, and Chemistries Different to those in the Base Cases

Section 6 of this TGD has provided general guidance for the Base Cases that cover the wide majority of fossil and combined cycle/HRSG plants around the world. **However, it is emphasized again that this is an IAPWS Technical Guidance Document and that, depending on local requirements, the guidance and analytical processes may need to be adapted and customized for some plants, as there cannot be one set of AIL procedures and monitoring tools that can be applied to every plant worldwide.** This customization could be a very important step in maintaining AIL and oxygen control for each specific plant. The emphasis of this section is on equipment and cycle chemistry features that could change the control of AIL on a plant and thus on corrosion and performance aspects of the plant. Is AIL always important? For instance, on a generating plant that provides supply steam to an associated facility with or without condensate

return. How is AIL approached on units with back-pressure turbines? Do all plants need to control oxygen at < 10 ppb ( $\mu\text{g}/\text{kg}$ ) at the CPD?

### 7.1 Examples for Different Units with Differences in Cycle Chemistry, Chemistry Equipment (such as Condensate Polishing Plant (CPP)), and Materials

Appendices A–E provide some guidance for a number of different combinations of unit design and cycle chemistry in terms of identifying the differences between AIL, organics, and salt water contamination. Appendix F provides information for plants that add a FFS. Similar tables can be constructed for specific units that vary from the Base Cases in Section 6.

For plants with copper alloy condenser tubes, particularly in the air removal section, high air in-leakage combined with ammonia feedwater treatment can accelerate steamside grooving corrosion and stress corrosion cracking.

### 7.2 Challenges in Plants with Air-cooled Condensers (ACC)

AIL is a particular problem in units with ACC for a number of reasons. ACCs are inherently performance-limited due to the inefficiency of air cooling requiring large surface areas (potentially available for air ingress), and high air ingress during elevated ambient temperatures may well result in a unit trip. In some cases, additional fans may be required to maintain condenser vacuum, resulting in increased energy penalty. During cold ambient conditions, AIL may result in freezing and potential heat exchanger tube rupture. There is much discussion at the annual ACCUG (ACC Users Group) meetings of: a) how to measure/monitor AIL around the ACC, and b) whether any AIL is occurring around the ACC or in the usual places delineated in Section 3.4. For some units with ACC there is a deaerator (DA) on the Condensate Storage Tank (CST), and then < 20 ppb ( $\mu\text{g}/\text{kg}$ ) oxygen will be achievable in the condensate to the plant. Sometimes units with ACC have a DA on the makeup line also into the CST.

Typical locations of AIL in Air-cooled Condensers (ACC) include:

- Cracked welds (often due to freezing and/or poor quality welds)
  - Lower distribution section (ACC)
  - Upper distribution duct (ACC)
- Open valves
- Duct isolation valves
- Steam traps
- Rupture discs
- Leaking flanges (from factory or field)
  - Flanges on steam turbine crossover piping
  - Steam turbine rupture discs
- Low pressure turbine exhaust (ACC)
- Loose instrument fittings/connections
- Leaks under insulation
- Exhaust duct manway, flange, and riser bellows
- Condensate receiver tank
- Inter-condenser (IC) drain
  - Expansion joints in ACC ductwork
  - Riser duct isolation valve packing
  - Dephlegmator (air removal) tube section

- Internal / external HX tube corrosion
- Expansion-type rupture disks on main ACC exhaust duct

The techniques to monitor AIL on ACC include some of the techniques described in Section 4, but with additional challenges. The ACC is very large and thus time-consuming to evaluate comprehensively (perhaps 20,000 heat exchange tubes / 40,000 welds in an average-sized unit). Many of the ACC components are difficult to physically access. Conventional AIL test methods (e.g., tracer gas) are very challenging due to air currents resulting from normal fan operation; i.e., unless the tracer gas is sprayed directly onto the leak, it may not be drawn into the vacuum and detected. A vacuum decay test can be very helpful to confirm the presence of AIL. Besides helium leak testing, somewhat more novel techniques such as acoustic testing and infrared (IR) surveys can also be conducted; in the case of AIL, cooler areas should be indicated by IR.

### 7.3 Challenges in Plants with Heller Systems

A properly designed dry cooling tower of a Heller system should not be a source of air in-leakage into the water/steam cycle. In the distant past, little attention was paid to potential oxygen infusion to the steam/water cycle from the tower, because historically the majority of these earlier Heller applications used some kind of oxygenated treatment. However, more recently (last 15 years) the cooling tower design solutions ensure that there is no air in-leakage from the dry tower that would in any way influence condensate oxygen content.

The most economic, common variant of the Heller system employs aluminum heat exchangers in the dry cooling tower, where oxygen content higher than 10 ppb ( $\mu\text{g}/\text{kg}$ ) is favorable to maintain the protective oxide layers on the internal surfaces of the aluminum parts. Considering that a Heller system is in a common closed circuit with the water/steam cycle due to mixing of condensate and cooling water in the jet condenser, it would be a disproportionate effort to elevate the oxygen content of the total cooling water flow (which is approximately 30 to 70 times the condensate flow, depending on system specifics) for the cooling tower, and reduce it again in the condensate. In addition, due to practical water management reasons, cycle makeup is usually added in the jet condenser where its deaeration to 10 ppb oxygen would require a currently non-standard specific thermal solution. So, there are benefits for units with Heller Towers and Jet Condenser to operate with condensate oxygen levels of 20 ppb ( $\mu\text{g}/\text{kg}$ ) or more to control the corrosion and flow-accelerated corrosion processes in both the all-ferrous feedwater system and the aluminum coolers.

Of course, the air evacuation system should be selected to account for the expected air in-leakage that is in line with these quantities.

In regard to the specifics of a jet condenser itself, it is very similar in volume to a surface condenser for the same duty, so they do not differ in expected air in-leakage locations, air leak flow rate, and behavior from the vacuum drop test point of view. By its design, a jet condenser has significantly smaller TTD than a surface condenser (i.e., it is more effective from the thermodynamic point of view). However, excess air in-leakage will increase the TTD of a jet condenser the same way as it increases the TTD of a surface condenser.

### 7.4 Plants Sited Near High Air Pollution Environments

Air in-leakage can pose significant challenges in plants sited near high air pollution environments. Examples include combined cycle HRSG plants inside or adjacent to hydrocarbon processing facilities, steel mills, pulp & paper mills, and even large airports.

**Airports.** Although aircraft engines generally combust fuel efficiently, large (international and regional) airports handle mostly larger aircraft which have disproportionately higher emissions than small aircraft. Large airports (with increasing levels of aircraft movements) often generate a high concentration of pollutant emissions stemming from both aircraft and surface traffic at ground level.

In the context of power plant cycle chemistry and AIL, the main sources of air pollution of concern at large airports are: (a) exhaust gases from aircraft engines (jet fuel/kerosene and diesel), and (b) direct fuel emissions from refueling aircraft and larger dust particles from tires, brakes, asphalt, etc.

The key pollutants can be divided into:

- Polycyclic aromatic hydrocarbons (PAHs)
- Volatile organic compounds (VOCs)
- Inorganic gases like sulfur dioxide (SO<sub>2</sub>)
- Nitrogen oxides (NO<sub>x</sub>) and Particulate matter (PM)
- Carbon dioxide

Polycyclic aromatic hydrocarbons (PAHs) are a group of organic compounds consisting of fused aromatic rings. In airports, PAHs are mainly produced due to incomplete combustion in aircraft and diesel engines. PAHs will exist bound to particulate matter and as gases in the exhaust gas.

Volatile organic compounds (VOCs) are a very large group of organic compounds mainly present as gases. The term VOCs is meant to include compounds such as benzene, aldehydes, ketones, and other low molecular weight organics.

Jet fuel contains high concentrations of sulfur – about 1000 ppm. In comparison, the sulfur content in aircraft diesel fuel is 10 ppm, i.e., approximately 100 times lower than that in jet fuel. In engines, most sulfur is oxidized to SO<sub>2</sub>, which leaves the engine as SO<sub>2</sub> or sulfate particles (e.g., ammonium sulfate particles). Aircraft engines are a key source of SO<sub>2</sub> in airports. Nitrogen oxides (NO<sub>x</sub>) consist of nitrogen oxide (NO) and nitrogen dioxide (NO<sub>2</sub>). NO<sub>x</sub> is formed in aircraft jet and diesel engines when free nitrogen (N<sub>2</sub>) is oxidized under elevated temperature. Ultrafine particles, mostly organic, are formed in aircraft and diesel engines due to incomplete combustion and in the surrounding air as residual fuel condensates. Aviation is also a significant and growing source of carbon dioxide emissions.

Thus, it is clear from the above that any AIL in plants sited near major airports will potentially introduce significant levels of acid radicals such as sulfate and nitrite; for example, NO<sub>2</sub> dissolves in water forming both nitrous acid and nitric acid, HNO<sub>3</sub>. Both sulfate and nitrite are associated with an increased risk of stress corrosion cracking in higher alloys such as those used in a variety of power plant components that touch the steam-water cycle.

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**Appendix A – Base case a): Conventional plants with drum units, all-ferrous feedwater systems, no reducing agent, non-copper tubed condensers, with a condensate polisher, and not cooled by seawater or brackish water.**

Source of Contamination: Measurement	Air In-Leakage	Organics	Salt/acid
<b>C (conductivity)</b>	Insignificant increase	Insignificant or no increase	Often insignificant increase, may be observed in condensate, e.g., by cooling water leaking in
<b>CACE (conductivity after cation exchange)</b>	Increase, 0.1–0.4 $\mu\text{S}/\text{cm}$ or even more, in condensate stream where AIL occurs. Normal level downstream CPP, i.e., in feedwater and steam. If condensate from district heating is fed to the condensate system downstream of the CPP, there may be an increase in CACE upstream of the deaerator.	Increasing levels through condensate, feedwater, and steam due to degradation of organics. Often marked increase from feedwater to steam due to fast degradation in boiler. Normal levels after CPP, since undissociated organics may pass or adsorb on the resins.	Increase at sample points downstream of contaminant entrance point. Steepness of increase vs. time decreases along flow path due to dilution, but approximately same level is reached. Levels in steam can increase due to carryover effects, Clearly increased levels in boiler water due to separation of salts with water and steam in drum. Normal level after CPP, if not excessive contamination.
<b>DO (dissolved oxygen)</b>	Increased level in condensate and LP feedwater when AIL occurs, if leakage is below or close to water line. No or small increase in condensate, if leakage occurs above the water line. Normal level in HP feed water due to deaeration.	No change compared to normal levels	No change compared to normal levels
<b>DCACE (degassed CACE)</b>	Significant difference between CACE and DCACE. Slightly increased level of DCACE (incomplete degassing) or no change relative to normal CACE in sample points with increased CACE.	Increasing difference between CACE and DCACE along the flow path and especially from feedwater to steam due to $\text{CO}_2$ from degradation.	No (or slight) increase in difference between CACE and DCACE along flow path.
<b>Na (sodium)</b>	Trace levels everywhere. Should be $< 2 \mu\text{g}/\text{kg}$ in steam. May increase depending on environment, but not necessarily.	May increase depending on the source of organics, but not necessarily.	Abrupt increase on salt contamination, no increase on acid contamination.
<b>Grab samples</b>	Trace levels of anions and NVOC everywhere	Increased levels of NVOC, formate, and acetate indicate presence of organics	High levels of inorganic anions ( $> 10 \mu\text{g}/\text{kg}$ ) indicate salt/acid. No increase in NVOC
<b>Remark</b>	Most often AIL may be identified securely by on-line measurements alone. If in doubt, analyze grab samples.	Analysis of grab samples recommended when this source is expected	Analysis of grab samples recommended when this source is expected



**Appendix B – Base case b): Conventional plants with drum units, mixed-metallurgy feedwater systems, copper tubed condensers, without a condensate polisher, and not cooled by seawater or brackish water**

Source of contamination: Measurement	Air In-Leakage	Organics	Salt/acid
<b>C (conductivity)</b>	Insignificant increase.	Insignificant or no increase.	Often insignificant increase, may be observed in condensate, e.g., by cooling water or softened district heating water in-leakage.
<b>CACE (conductivity after cation exchange)</b>	Increase, 0.1–0.4 $\mu\text{S}/\text{cm}$ or even more, in condensate stream where AIL occurs. Increased levels in sample points downstream of AIL entrance point. However, no or slight increase in boiler water.	Increasing levels through condensate, feedwater, and steam due to degradation of organics. Often marked increase from feedwater to steam due to fast degradation in boiler. Small increase in boiler water due to accumulation of organic acids.	Increase at sample points downstream of contaminant entrance point. Steepness of increase vs. time decreases along flow path due to dilution, but approximately same level is reached. Levels in steam can increase due to carryover effects, Clearly increased levels in boiler water due to separation of salts with water and steam in drum.
<b>DO (dissolved oxygen)</b>	Increased level in condensate and LP feedwater when AIL occurs, if leakage is below or close to water line. No or small increase in condensate, if leakage occurs above the water line. Normal level in HP feed water due to deaeration.	No change compared to normal levels	No change compared to normal levels
<b>DCACE (degassed CACE)</b>	Significant difference between CACE and DCACE. Slightly increased level of DCACE (incomplete degassing) or no change relative to normal CACE in sample points with increased CACE	Increasing difference between CACE and DCACE along the flow path and especially from feedwater to steam due to $\text{CO}_2$ from degradation.	No (or slight) increase in difference between CACE and DCACE along flow path.
<b>Na (sodium)</b>	Trace levels everywhere. Should be $< 2 \mu\text{g}/\text{kg}$ in steam. May increase depending on environment, but not necessarily.	May increase depending on the source of organics, but not necessarily.	Abrupt increase on salt contamination, no increase on acid contamination.
<b>Grab samples</b>	Trace levels of anions and NVOC everywhere.	Increased levels of NVOC, formate, and acetate indicate presence of organics.	High levels of inorganic anions ( $> 10 \mu\text{g}/\text{kg}$ ) present in samples. No increase in NVOC
<b>Remark</b>	Most often AIL may be identified securely by on-line measurements alone. If in doubt, analyze grab samples.	Analysis of grab samples recommended when this source is expected.	Analysis of grab samples recommended when this source is expected.

**Appendix C1 – Base case c) on AVT(O): Conventional plants with once-through sub-, super-, and ultra-supercritical units, all-ferrous feedwater systems, non-copper tubed condensers, with a condensate polisher, and not cooled by seawater or brackish water.**

Source of Contamination: Measurement	Air In-Leakage	Organics	Salt/acid
<b>C (conductivity)</b>	Insignificant increase.	Insignificant or no increase.	Often insignificant increase, may be observed in condensate, e.g., by cooling water in-leakage in condenser.
<b>CACE (conductivity after cation exchange)</b>	Increase, 0.1–0.4 $\mu\text{S}/\text{cm}$ or even more, in condensate stream where AIL occurs. Normal level downstream CPP, i.e., in feedwater and steam. If condensate from district heating is fed to the condensate train downstream of the CPP, there may be an increase upstream of the deaerator.	Increasing levels through condensate, feedwater, and steam due to degradation of organics. Often marked increase from feedwater to steam due to fast degradation in boiler. Normal levels after CPP, since undissociated organics may pass or adsorb on the filters.	Increase at sample points downstream of contaminant entrance point. Steepness of increase vs. time decrease along flow path due to dilution, but approximately same level is reached. Normal level after CPP, if not excessive contamination.
<b>DO (dissolved oxygen)</b>	Increased level in condensate and LP feedwater when AIL occurs, if leakage is below or close to water line. No or small increase in condensate, if leakage occurs above the water line. Normal level in HP feedwater due to deaeration.	No change compared to normal levels.	No change compared to normal levels.
<b>DCACE (degassed CACE)</b>	Significant difference between CACE and DCACE. Slightly increased level of DCACE (incomplete degassing) or no change relative to normal CACE in sample points with increased CACE.	Increasing difference between CACE and DCACE along the flow path and especially from feedwater to steam due to $\text{CO}_2$ from degradation.	No (or slight) increase in difference between CACE and DCACE along flow path.
<b>Na (sodium)</b>	Trace levels everywhere. Should be $< 2 \mu\text{g}/\text{kg}$ in steam. May increase depending on environment, but not necessarily.	May increase depending on the source of organics, but not necessarily.	Abrupt increase on salt contamination, no increase on acid contamination.
<b>Grab samples</b>	Trace levels of anions and NVOC everywhere.	Increased levels of NVOC, formate, and acetate indicate presence of organics.	High levels of inorganic anions ( $> 10 \mu\text{g}/\text{kg}$ ) indicate salt/acid. No increase in NVOC.
<b>Remark</b>	Most often AIL may be identified securely by on-line measurements alone. If in doubt, analyze grab samples.	Analysis of grab samples recommended when this source is expected.	Analysis of grab samples recommended when this source is expected.

**Appendix C2 – Base case c) on OT: Conventional plants with once-through sub-, super-, and ultra-supercritical units, all-ferrous feedwater systems, non-copper tubed condensers, with a condensate polisher, and not cooled by seawater or brackish water**

Source of contamination: Measurement	Air In-Leakage	Organics	Salt/acid
<b>C (conductivity)</b>	Insignificant increase	Insignificant or no increase	Often insignificant increase, may be observed in condensate, e.g., by cooling water in-leakage in condenser.
<b>CACE (conductivity after cation exchange)</b>	Increase, 0.1–0.4 $\mu\text{S}/\text{cm}$ or even more, in condensate stream where AIL occurs. Normal level downstream CPP, i.e., in feedwater and steam. If condensate from district heating is fed to the condensate train downstream of the CPP, there may be an increase upstream of the deaerator.	Increasing levels through condensate, feedwater, and steam due to degradation of organics. Often marked increase from feedwater to steam due to fast degradation in boiler. Normal levels after CPP, since undissociated organics may pass or adsorb on the filters.	Increase at sample points downstream of contaminant entrance point. Steepness of increase vs. time decrease along flow path due to dilution, but approximately same level is reached. Normal level after CPP, if not excessive contamination.
<b>DO (dissolved oxygen)</b>	Increased level in condensate and LP feedwater when AIL occurs, if leakage is below or close to water line. No or small increase in condensate, if leakage occurs above the water line. Even for units on OT the IAPWS guidance suggests < 10 ppb oxygen at the CPD. Oxygen for OT is added downstream of this.	No change compared to normal levels	No change compared to normal levels
<b>DCACE (degassed CACE)</b>	Significant difference between CACE and DCACE. Slightly increased level of DCACE (incomplete degassing) or no change relative to normal CACE in sample points with increased CACE	Increasing difference between CACE and DCACE along the flow path and especially from feedwater to steam due to $\text{CO}_2$ from degradation.	No (or slight) increase in difference between CACE and DCACE along flow path.
<b>Na (sodium)</b>	Trace levels everywhere. Should be < 2 $\mu\text{g}/\text{kg}$ in steam. May increase depending on environment, but not necessarily.	May increase depending on the source of organics, but not necessarily.	Abrupt increase on salt contamination, no increase on acid contamination.
<b>Grab samples</b>	Trace levels of anions and NVOC everywhere.	Increased levels of NVOC, formate and acetate indicate presence of organics.	High levels of inorganic anions (> 10 $\mu\text{g}/\text{kg}$ ) indicate salt/acid. No increase in NVOC.
<b>Remark</b>	Most often AIL may be identified securely by on-line measurements alone. If in doubt, analyze grab samples.	Analysis of grab samples recommended when this source is expected.	Analysis of grab samples recommended when this source is expected.

**Appendix D – Base case d): Multi-pressure combined cycle/HRSG drum units, no copper alloys, independently fed LP, IP, and HP circuits, no condensate polisher for AVT(O), no reducing agent added to the cycle, and not cooled by seawater or brackish water. The drum pressures on this base case are considered to be LP 0.5 MPa (70 psi), IP 2.4 MPa (350 psi), and HP 14 MPa (2000 psi).**

Source of contamination: Measurement	Air In-Leakage	Organics	Salt/acid
<b>C (conductivity)</b>	Insignificant increase.	Insignificant or no increase.	Often insignificant increase, may be observed in condensate, e.g., by cooling water or softened district heating water in-leakage.
<b>CACE (conductivity after cation exchange)</b>	Increase, 0.1–0.4 $\mu\text{S}/\text{cm}$ or even more, in condensate stream where AIL is below or close to water line. Increased levels in sample points downstream of entrance point. However, no or slight increase in evaporator water.	Increasing levels through condensate, feedwater, and steam due to degradation of organics. Often marked increase from feedwater to steam due to fast degradation in evaporator. Small increase in evaporator water due to accumulation of organic acids. CACE levels increase in order: $\text{FW} \leq \text{LP} < \text{IP} < \text{HP}$ due to enhanced degradation at higher temperature and pressure.	Increase at sample points downstream of contaminant entrance point. Steepness of increase vs. time decreases along flow path due to dilution, but approximately same level is reached. Clearly reduced levels in steam (unless attemperation continues) and clearly increased levels in evaporator water due to separation of salts with water and steam in drum.
<b>DO (dissolved oxygen)</b>	Increased level in condensate and feedwater when AIL occurs, if leakage is below or close to water line. No or small increase in condensate, if leakage occurs above the water line.	No change compared to normal levels.	No change compared to normal levels.
<b>DCACE (degassed CACE)</b>	Significant difference between CACE and DCACE. Slightly increased level of DCACE (incomplete degassing) or no change relative to normal CACE in sample points with increased CACE.	Increasing difference between CACE and DCACE along the flow path and especially from feedwater to steam due to $\text{CO}_2$ from degradation.	No (or slight) increase in difference between CACE and DCACE along flow path.
<b>Na (sodium)</b>	Trace levels everywhere. Should be $< 2 \mu\text{g}/\text{kg}$ in steam. May increase depending on environment, but not necessarily.	May increase depending on the source of organics, but not necessarily.	Abrupt increase on salt contamination, no increase on acid contamination.
<b>Grab samples</b>	Trace levels of anions and NVOC everywhere.	Increased levels of NVOC, formate, and acetate indicate presence of organics.	High levels of inorganic anions ( $> 10 \mu\text{g}/\text{kg}$ ) present in samples. No increase in NVOC.
<b>Remark</b>	Most often AIL may be identified securely by on-line measurements alone. If in doubt, analyze grab samples.	Analysis of grab samples recommended when this source is expected.	Analysis of grab samples recommended when this source is expected.

**Appendix E – Base case e): Multi-pressure combined cycle/HRSG drum units, no copper alloys, with the LP drum feeding the IP and HP circuits, no condensate polisher for AVT(O), no reducing agent added to the cycle, and not cooled by seawater or brackish water. The drum pressures on this base case are considered to be LP 0.5 MPa (70 psi), IP 2.4 MPa (350 psi), and HP 14 MPa (2000 psi)**

Source of contamination: Measurement	Air In-Leakage	Organics	Salt/acid
<b>C (conductivity)</b>	Insignificant increase.	Insignificant or no increase.	Often insignificant increase, may be observed in condensate, e.g., by cooling water or softened district heating water in-leakage.
<b>CACE (conductivity after cation exchange)</b>	Increase, 0.1–0.4 $\mu\text{S}/\text{cm}$ or even more, in condensate stream where AIL occurs. Increased levels in sample points downstream of entrance point. Slight increase in evaporator water.	Increasing levels through condensate, feedwater, and steam due to degradation of organics. Often marked increase from feedwater to steam due to fast degradation in boiler. Small increase in boiler water due to accumulation of organic acids. CACE levels increase in order: $\text{Cond} \leq \text{LP} < \text{IP} < \text{HP}$ due to enhanced degradation at higher temperature and pressure.	Increase at sample points downstream of contaminant entrance point. Steepness of increase vs. time decreases along flow path due to dilution, but approximately same level is reached. Clearly reduced levels in steam (unless attemperation is continued) and clearly increased levels in boiler water due to separation of salts with water and steam in drum.
<b>DO (dissolved oxygen)</b>	Increased level in condensate when AIL occurs, if leakage is below or close to water line. No or small increase in condensate, if leakage occurs above the water line.	No change compared to normal levels	No change compared to normal levels
<b>DCACE (degassed CACE)</b>	Significant difference between CACE and DCACE. Slightly increased level of DCACE (incomplete degassing) or no change relative to normal CACE in sample points with increased CACE	Increasing difference between CACE and DCACE along the flow path and especially from feedwater to steam due to $\text{CO}_2$ from degradation.	No (or slight) increase in difference between CACE and DCACE along flow path.
<b>Na (sodium)</b>	Trace levels everywhere. Should be $< 2 \mu\text{g}/\text{kg}$ in steam. May increase depending on environment, but not necessarily.	May increase depending on the source of organics, but not necessarily	Abrupt increase on salt contamination, no increase on acid contamination
<b>Grab samples</b>	Trace levels of anions and NVOC everywhere	Increased levels of NVOC, formate, and acetate indicate presence of organics	High levels of inorganic anions ( $> 10 \mu\text{g}/\text{kg}$ ) present in samples No increase in NVOC
<b>Remark</b>	Most often AIL may be identified securely by on-line measurements alone. If in doubt, analyze grab samples	Analysis of grab samples recommended when this source is expected	Analysis of grab samples recommended when this source is expected

**Appendix F – Drum/combined cycle/HRSR, no CPP – FFS/AVT Cycle Chemistry**

Source of contamination: Measurement	Air In-Leakage	Organics	Salt/acid
<b>C (conductivity)</b>	Insignificant increase.	Insignificant or no increase.	Often insignificant increase, may be significant in condensate, e.g., by salt water or softened district heating water in-leakage in condenser.
<b>CACE (conductivity after cation exchange)</b>	Increase, 0.1–0.4 $\mu\text{S}/\text{cm}$ or even more, in condensate stream where AIL occurs. Increased levels in sample points downstream of AIL entrance point. If FFAP is being used, increases can often be on a high background value, 0.3–1 $\mu\text{S}/\text{cm}$ from degradation products.	Increasing levels in condensate, feedwater, and steam systems due to degradation of organics. Often marked increase from feedwater to steam due to fast degradation in boiler. Increase may be hidden in high background value from degradation products.	Increase at sample points downstream of contaminant entrance point. Steepness of increase vs. time decreases along flow path due to dilution, but approximately same level is reached. Levels in steam can increase due to carryover effects and attemperation, Clearly increased levels in boiler water due to separation of salts with water and steam in drum.
<b>DO (dissolved oxygen)</b>	Increased level in condensate and LP feedwater when AIL occurs, if leakage is below or close to water line. No or small increase in condensate, if leakage occurs above the water line. Normal level in HP feed water due to deaeration.	No change compared to normal levels	No change compared to normal levels
<b>DCACE (degassed CACE)</b>	Increased difference between CACE and DCACE. The difference is seen on a background value from $\text{CO}_2$ .	Increasing difference between CACE and DCACE along the flow path and especially from feedwater to steam due to $\text{CO}_2$ from degradation. This may be hidden by the levels resulting from conditioning.	Increasing difference between CACE and DCACE along the flow path and especially from feedwater to steam due to formation of $\text{CO}_2$ from degradation.
<b>Na (sodium)</b>	Trace levels everywhere. Should be $< 2 \mu\text{g}/\text{kg}$ in steam. May increase depending on environment, but not necessarily.	May increase depending on the source of organics, but not necessarily.	Abrupt increase on salt contamination, no increase on acid contamination.
<b>Grab samples</b>	Trace levels of inorganic anions everywhere if FFS used. Formate, acetate, and NVOC corresponding to level of conditioning agent.	Increased levels of NVOC, formate, and acetate indicate presence of organics. The levels present under normal conditions should be available for comparison.	High levels of inorganic anions ( $> 10 \mu\text{g}/\text{kg}$ ) present in samples. No increase in NVOC.
<b>Remark</b>	Most often AIL may be identified securely by on-line measurements alone. If in doubt, analyze grab samples.	Analysis of grab samples recommended when this source is expected.	Analysis of grab samples recommended when this source is expected.