Trends in HRSG Reliability – A 10-Year Review

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ABSTRACT

By 2008 the authors had conducted assessment surveys at a small number of combined cycle/heat recovery steam generator (HRSG) plants in the areas of cycle chemistry, flow-accelerated corrosion (FAC), and thermal transients. The results clearly showed some important trends on why the major failure/damage events occurred on these plants. In the interim period the authors have extended the number of plants worldwide to 90 to allow a ten-year review of combined cycle/HRSG reliability. There has been a remarkable increase in knowledge and understanding of the main drivers of damage/failure, and in combination with the tools developed for the assessments, this paper now includes clear direction on how to address the reliability issues retroactively and how to avoid them proactively. The major cycle chemistry influenced issues are: HRSG Tube Failures due to FAC, under-deposit corrosion, deposits in high pressure (HP) evaporators, and failure in the phase-transition zone of the steam turbine. The main thermal transient aspects of thermal and corrosion fatigue relate to inappropriate/inadequate operation and maintenance of attemperators, poor drain control of superheaters and reheaters, HP drum ramp rates, and forced cooling. Another emerging issue is severe erosion of bypass pressure control valves. The paper discusses each and provides directions by which plants can avoid the issues in the future.

1 BACKGROUND

In 2008 the authors initiated a program to assess the health of combined cycle/heat recovery steam generator (HRSG) plants as it had been noticed that the ranking and frequency of failures and damage in these plants had remained almost the same over the previous twenty years. The goal of the work was to assist operators to be proactive in identifying the key drivers for these cycle chemistry and thermal transient induced mechanisms. In the former, the assessments addressed the factors for flow-accelerated corrosion (FAC), under-deposit corrosion (UDC), corrosion products, and pitting. In the latter, the assessments addressed thermal fatigue and creep fatigue resulting from condensate formation and drainage in superheaters and reheaters, as well as drum ramp rates, downcomer cracking, high pressure (HP) bypass pressure control valve (PCV) erosion, and the operation of attemperating systems. By 2009, 11 plants had been surveyed and the results were published [1,2]. The compiled results clearly showed the weaknesses in the cycle chemistry and thermal transient areas which when left unaddressed resulted in failure/damage.

Since this early work, the authors have now conducted assessments on 90 plants worldwide for the cycle chemistry/FAC and 54 plants for thermal transients.

The essence of these assessments was originally to help the operators identify and address previously undetected problems proactively. This was based on the authors' strong implicit belief that the HRSG Tube Failures and damage mechanisms, mentioned above, are so well understood that the key drivers (or root causes) can clearly be identified and eliminated prior to inception of serious damage and failure. While this is still the case in 2019, more recently many of the assessments have been conducted to identify the mechanism and root causes of actual failures/damage that have been experienced by a plant.

A very wide range of plants has been assessed worldwide which include:

- 20 HRSG manufacturers
- 5 gas turbine (GT) manufacturers (B, C, E, F, G, H, Industrial and Aero derivative)
- 9 steam turbine manufacturers (condensing and non-condensing)
- Two-shaft and single-shaft arrangements
- Horizontal and vertical gas path HRSGs (HGP and VGP)
- Recirculating (drum-type) and once-through
- Single-, two-, and three-pressure HRSGs
- 1x1, 2x1, and 3x1
- Reheat and non-reheat
- Base load, multi-shifting, and ultra-fast start
- Cogeneration, purpose-built power generation, and conventional plant repower
- HRSGs in oil, chemical, gas, liquefied natural gas (LNG), and aluminum refineries
- Spray interstage and final attemperation, HP superheater and reheater steam bypass attemperation

- Duct-fired and unfired
- Exhaust bypass damper, exhaust stack isolation damper, no dampers
- River, seawater, and lake water cooling
- Wet- and air-cooled condenser, air-cooled heat exchanger, cooling tower
- < 1 000 to 130 000 operating hours, < 50 to > 3 000 starts
- "Every possible" type of cycle chemistry

In 2009, the initial assessments made it clear that almost independent of the manufacturer or type of HRSG, there are common features associated with the cycle chemistry operation and the thermal transient drivers. It was found that these are rarely identified, and because they are allowed to continue without remediation, these repeating or continuing features eventually lead to failure or damage. There was very little variation across the fleet worldwide as the 2009 paper clearly illustrated. In some ways this was thought to be fortunate because it should allow the operator to review the data in that paper and decide to make the necessary changes knowing that there was a track record in alleviating and correcting the drivers which are commonly present and active. The authors indicated in 2009 that solutions to the cycle chemistry influenced areas were much more mature than those to the thermal transient issues. But in the intervening years the understanding of the thermal transient issues has advanced tremendously through recognition of the factors in that paper along with the user groups and forums that the authors run annually in Australasia, Europe, the US, and Canada. This maturity has led to a couple of additional thermal transient issues which are now included in the plant assessments: HP bypass pressure control valve erosion, attemperator spray water leaking, and forced cooling following shutdown.

After ten years it is time to see whether both the chemistry and thermal transient areas are now established enough to allow operators to specify the necessary features to eliminate these drivers in new plant designs, and take corrective action in existing plants. But one of the important aspects of assembling this large amount of data is to determine if organizations are more proactive with plants which haven't already experienced failure. This current publication provides updated results on both aspects.

Plant Assessment Process

The process used by the authors was initially described in the 2009 paper. A few additional items are now incorporated in the process. The assessments are usually conducted during a two-day visit to the plant by the authors to review the design, construction, operation, and cycle chemistry of the combined cycle and HRSG. Each plant is benchmarked using the same process described in the 2009 paper, which provides a ranking on a worldwide basis.

On the cycle chemistry/FAC side, review and assessment of the following take place:

a. The heat balance diagrams for the plant at representative loads;
b. The detailed arrangements of the HRSG circuits (side elevations) with materials of construction of tubes, headers, piping, and drums. Detailed design of tube/header connections and whether tubes have bends as they approach the headers;
c. Thermal performance of HRSGs (fluid and flue gas temperatures and pressures);
d. The cycle chemistry treatments in the condensate and feedwater, and in each drum including the actual chemicals added to the plant. If proprietary chemicals are used, then the compositions are needed. Both operating and shutdown conditions are included;
e. The installed on-line instrumentation and how close it comes to the International Association for the Properties of Water and Steam (IAPWS) [3] "Level of Instruments", and whether they are alarmed in the control room;
f. Review of any cycle chemistry influenced HRSG Tube Failures (HTF) and steam turbine damage, failures, pitting, and deposits;
g. General inspection reports of HRSG major pressure vessels (drums, headers, deaerator if installed);
h. Particular review of the FAC potential for the unit, which includes the materials identification and operating temperatures of the low pressure (LP) and intermediate pressure (IP) circuits which are known to be susceptible to FAC [4]. Review of previous FAC predictions and/or inspections;
i. Review of historian data on cycle chemistry for representative time periods to derive the typical operating chemistries (called 90 % values);
j. The history of monitored total iron levels in the feedwater and drums;
k. Review of plant chemistry manual.

On the thermal transient side, review and assessment of the following take place:

l. GT original equipment manufacturer (OEM) and model including any upgrades to compressor, combustion system, turbine, and controls;
m. Piping and instrumentation diagrams (P&IDs) of HRSG, steam, water, and gas path systems;
n. For superheater and reheater: dimensions, materials, and arrangement of tubes, headers, interconnecting pipes, attemperators, vents, drains, and flash tank;
o. For LP economizer: dimensions, materials, and arrangement of tubes, headers, interconnecting pipes, drains, recirculation system, and condensate pipe;

p. For superheaters, reheaters, evaporators, and economizers: arrangement and condition of sidewall and between module gas baffles;
q. For high energy piping (HP, hot reheat, cold reheat) dimensions, materials, arrangement/slope, and drains;
r. For bypass systems (HP turbine and IP turbine) arrangement, drains, prewarming, operating procedures;
s. For 1x1 units and both lead and lag units in 2x1, 3x1, etc. plants: key historical data collection system (DCS) data during a typical cold start, hot start, normal shutdown, and forced cooling;
t. For 1x1 units and both lead and lag units in 2x1, 3x1, etc. plants: operating procedures used for cold starts, hot starts, normal shutdowns, and forced cooling;
u. Attemperator control and protective logic for HP superheater, reheater, HP bypass, and IP bypass.

1.1 INTRODUCTION TO COMBINED CYCLE/ HRSG RELIABILITY – FAILURE AND DAMAGE MECHANISMS

After more than 20 years the main failure and damage mechanisms influenced by the cycle chemistry and thermal transients which have caused major reliability issues in combined cycle/HRSG plants have become established.

Cycle Chemistry Influenced Failure and Damage

It is not surprising that because the cycle chemistry "touches" all the parts of a combined cycle plant, it controls the availability and reliability of these plants. It has been suggested over the last 20 years that the cycle chemistry influences about 70 % of all the failure and damage mechanisms in combined cycle/HRSG plants with multiple pressures. These can be categorized as follows:

- ■ HRSG Tube Failures
  - FAC in LP and IP evaporators, LP, IP, and HP economizers (single- and two-phase) [1,4]
  - Under-deposit corrosion (UDC) in HP evaporators of both vertical and horizontal gas path HRSGs (mainly hydrogen damage but acid phosphate corrosion and caustic gouging have also occurred but less frequently over the last 10 years) [5–7]
  - Corrosion fatigue in LP evaporators and economizers
  - Pitting (often evidenced as tubercles in pressure vessels (drums, deaerators))
- ■ FAC in air-cooled condensers with main damage by two-phase FAC at air-cooled condenser (ACC) tube entries in upper ducts [4,8,9]
- ■ Steam turbine damage
  - Corrosion fatigue of blades and disks in the phase transition zone (PTZ) of the LP turbine
  - Stress corrosion cracking (SCC) of blades and disks in the PTZ of the LP turbine
  - Pitting from which all PTZ damage is initiated
  - Flow-accelerated corrosion (FAC)
  - Deposition of salts on the PTZ surfaces

Thermal Transient Influenced Failure and Damage

- ■ HRSG Tube Failures
  - Thermal creep fatigue in HP superheater and reheater at tube-to-header welds
  - Thermal fatigue in economizers at tube-to-header welds
  - Distortion out of line with other tubes (stretched tubes) in economizer, HP superheater and reheater
  - Accelerated thermal aging (overheating) of HP superheater and reheater tubes downstream of duct burners
  - Water/acid dewpoint corrosion in LP economizer (not entirely influenced by thermal transients but by feedwater inlet temperatures)
- ■ Steam piping failures
  - Thermal creep fatigue in HP superheater and reheater attemperator pipe girth welds
  - Thermal quench cracking in HP superheater and reheater attemperator pipes, elbows, and tees
  - Transient and permanent thermal distortion (hogging and humping) downstream and upstream of attemperators
  - Thermal fatigue in HP superheater and reheater drain pipes
  - Thermal fatigue in girth welds downstream of HP and IP bypass desuperheaters
  - Accelerated thermal aging (overheating) of pipe downstream of HP bypass pressure control valve
- ■ HP steam drum damage
  - Corrosion fatigue at shell-to-downcomer and shell-to-nozzle welds
- ■ Valve damage
  - Erosion of HP bypass PCV seat and plug (not influenced by thermal transients but by operating procedures)

1.2 CHANGING PERSPECTIVES ON HRSG FAILURE AND DAMAGE – PAST AND FUTURE

Although there are no "official" statistics for combined cycle/HRSG plants, the authors consider that the main failure and damage mechanisms in HRSG plants have changed very little over the last 20 years or more, indicating that the failures are repetitive and that plants continue to make the same mistakes and not proactively address the driving factors. Failures are still essentially addressed reactively as they occur. In many cases plant staff make no attempt to identify the failure mechanism by tube failure site removal and metallurgical analysis, and/or root cause assessment.

There are also damage/failures that have not occurred as frequently as those delineated in the last sub-section. Those known to the authors include: corrosion under insulation (CUI), back end corrosion, and nitrite damage SCC mechanisms. There are also those items which are operational and may not result in failure.

Some design features and practices which 10–15 years ago were anticipated to cause many failures did so, others did not, and some unanticipated thermal drivers of failures surfaced. For example, ligament cracking in HP superheater headers and tube-to-header failures due to differential expansion between the tube and HP superheater/reheater header borehole never really manifested as anticipated into big problems. On the other hand, leaking attemperator spray water has caused, and continues to cause, frequent thermal fatigue damage in steam HP superheater and reheater steam pipes.

There are already signs today, but the authors anticipate that some of the changing operating regimes will/could affect the future reliability and thus failure/damage. Some of these operating regimes and possible damage mechanisms include:

- More flexible operation accompanied by increased corrosion product transport and thermal transients;
- Increased startups and shutdowns leading to increased corrosion products, inadequate condensate/drain control, and attemperator related thermal transients;
- More low GT load operation leading to a shift in locations subject to FAC, higher demand for attemperator spray/overspray, and possibly higher tube/header/piping metal temperatures;
- GT upgrades leading to a shift in locations subject to FAC and unanticipated HRSG operating conditions such as higher metal temperatures and increased attemperator demand;
- 2x1 and 3x1 plants operating with increasing time periods at 1x1 and 2x1 operation, respectively. This increases the risks associated with GT low load operation and GT upgrades, but also changes the location of the more adverse environments in the phase transition zone of the LP steam turbine. The changed operation will mean increased shutdown periods for HRSGs, requiring more frequent shutdown protection for the non-operating unit;
- Faster starts leading to increased risk of inadequate draining of HP superheater/reheater and HP bypass PCV erosion;
- Forced cooling leading to increased thermal fatigue damage at HP drum nozzles, large thermal transients in HP and hot reheat (HRH) piping, and erosion of HP bypass PCV;
- Longer operating periods will lead gradually to overheating of HP superheater and reheater tubing/headers due to increased internal thicknesses of steam grown oxides, which have already been observed;
- Cycle chemistry requirements may need additional features with the main one being better shutdown protection. This provides ideal application for film forming substances (FFS), which will need to be applied properly according to IAPWS Guidance (Section 8 in [10]). Further discussion on this topic can be found in Section 2.1.

2 INTRODUCTION TO RELIABILITY ISSUES

Successful commercial operation of the plant requires that operating commitments such as startup times, duration on-line, and plant output capacity are routinely met. To do so requires that all critical plant equipment, including the HRSG, perform with a high degree of reliability. Some level of corrosion (gas side and steam/water side) and thermal degradation (creep and fatigue) are unavoidable in HRSG pressure parts. The key to reliable operation and long service life is limiting the rates of these damage mechanisms to those anticipated by the designer. Achieving a consistently high level of reliability requires a proactive management approach that seeks to identify and correct operating conditions/practices that result in equipment being exposed to conditions (chemical and thermal) outside those anticipated by the designer. In addition, when a pressure part failure occurs in spite of the foregoing best efforts, the commercially successful management approach must place a high priority on promptly and fully understanding what caused the failure, then promptly taking the corrective actions necessary to avoid a repeat failure. These post-failure activities are often referred to as root cause analysis (RCA). This approach has been proven to be very effective when supported by high level managers and consistently executed. This is largely because the most common failure mechanisms (various types of corrosion, fatigue, and creep) cause invisible, cumulative, and irreversible damage – providing the opportunity to prevent failures by not repeating the actions/conditions that cause the damage.

2.1 INTRODUCTION TO CYCLE CHEMISTRY ASPECTS AND IMPORTANCE OF REPEAT CYCLE CHEMISTRY SITUATIONS (RCCS)

The cycle chemistry treatments and control on combined cycle/HRSG plants influence a high percentage of the availability, reliability, and safety issues experienced on these plants worldwide. The equipment and materials of construction and the reliability depend on the internal surface protective oxides, the formation of which relates directly to the cycle chemistry treatments that are used in the condensate, feedwater, boiler/HRSG evaporator water, and steam. The optimum chemistry treatments are introduced briefly in this section and are directly related to the guidance provided by IAPWS [3,10–16]. The cycle chemistry damage and failure mechanisms are all influenced by not operating with these optimum treatments, which results in the protective oxides breaking down. The third part of this sub-section introduces the key analytical tools which have been developed by the authors and used in all the plant assessments worldwide to identify whether these failure and damage mechanisms will occur. This consists of identifying the number of Repeat Cycle Chemistry Situations (RCCS) currently applicable to a plant. These tools are introduced in this section and discussed in detail in Section 3.1 together with the statistics from the data base of 90 combined cycle assessments.

Cycle Chemistry Treatments for Combined Cycle/HRSG Plants

For the development of optimum cycle chemistry, it is important to note that all the cycle of the combined cycle plant must be considered. Most often the cause of the cycle chemistry influenced failure and damage mechanisms in a particular HRSG section or steam turbine does not originate at that location. For instance, condensate/feedwater corrosion products are transported into the HP evaporator and deposit. Also, any contaminants in the evaporator originating in the condensate can be carried over into the steam turbine.

The chemistry of the condensate and feedwater is critical to the overall reliability of HRSG plants. Corrosion and FAC take place in the feedwater of HRSG plants (preheaters and economizers), and the resulting corrosion products flow into the HRSG evaporators, where they deposit on heat transfer areas. These deposits can act in the HRSG evaporator as initiating centers for some of the tube failure mechanisms, and in the steam turbine as a source of either efficiency losses, blade/disk failures, or pitting. The choice of feedwater chemistry depends primarily on the materials of construction and secondly on the feasibility of maintaining purity around the water/steam cycle.

Most often a volatile alkalizing agent, usually ammonia, is added to the condensate/feedwater to increase the pH. Alternatively, an alkalizing amine can be added in place of ammonia. Film forming substances (FFS) can be added instead of the ammonia or amine. FFS include film forming amines (FFA), film forming amine products (FFAP), and film forming products (FFP) which don't contain an amine [10].

Condensate and feedwater cycle chemistry treatments

There are four main variations of volatile conditioning that can be applied to the condensate and feedwater:

AVT(R) – All-Volatile Treatment (Reducing) [11]

This treatment involves the addition of ammonia or an amine, an FFS, a blend of amines of lower volatility than ammonia, and 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 (from air in-leakage) of about 10 $\mu g \cdot kg^{-1}$ or less in the condensate (usually measured at the condensate pump discharge (CPD)), the resulting feedwater will have a reducing potential. Higher levels of oxygen (> 20 $\mu g \cdot kg^{-1}$) (due to high 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) should not be used in multi-pressure HRSG systems due to concerns for single-phase FAC as discussed in Section 4.

AVT(O) – All-Volatile Treatment (Oxidizing) [11]

This all-volatile treatment has emerged as the much preferred treatment over the last 25 years 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, an FFS, 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). In combined cycle/HRSG plants with relatively good control of air in-leakage (oxygen levels in the range 10–20 $\mu g \cdot kg^{-1}$), the resulting feedwater will yield a mildly oxidizing potential.

OT – Oxygenated Treatment [11]

Application of OT in combined cycle/HRSG plants is much rarer, but often it is found that the use of AVT(O) with low levels of oxygen (< 10 $\mu g \cdot kg^{-1}$) on these plants does not provide sufficient oxidizing power to passivate the very large internal surface areas associated with preheaters, LP, IP and HP economizers, and LP evaporators, especially if a deaerator is included in the LP circuit. In these cases, oxygen can be added between 30 and 50 $\mu g \cdot kg^{-1}$ in the condensate. A condensate polisher will be required to maintain a conductivity after cation exchange (CACE) of < 0.15 $\mu S \cdot cm^{-1}$ in the condensate and feedwater (boiler feed pumps).

FFS – Film Forming Substances [10]

FFS work in a different way from the conventional treatments by being adsorbed onto metal oxide/deposit surfaces, thus providing a physical barrier at the molecular or multi-molecular level between the water/water-steam and the surface. Evidence of adsorbed films is provided by the hydrophobic properties of the surfaces of drained components after treatment. There are three main active chemical substances which have been used historically: octadecylamine (ODA), oleylamine (OLA), and oleylpropanediamine (OLDA). As well as these compounds, other substances such as: alkalizing amines, emulsifiers, reducing agents, and dispersants (e.g., polycarboxylates) are often contained in commercial FFS. There is currently much confusion about their application for normal operation and for shutdown/layup, and there has not been any international guidance until a document issued recently by IAPWS [10] on deciding whether to use an FFS and whether it will provide a benefit to the plant. An FFS must be customized to each plant, which requires an extensive cycle chemistry review prior to application of the FFS. The FFS is added at the CPD or polisher outlet (if a polisher is included within the cycle). There are an increasing number of experience reports that FFS provide single- and, in some areas of the plant, two-phase FAC protection [4].

HRSG evaporator cycle chemistry treatments For some HRSGs the addition of solid alkalizing agents to the HRSG drum/evaporator water may be necessary in order to improve the tolerance to impurities and reduce the risk of corrosion. The alkalizing agents which can be used for this are tri-sodium phosphate (phosphate treatment (PT)) or sodium hydroxide (caustic treatment (CT)) used alone. The two can also be used in combination. The amounts of sodium hydroxide added have to be strictly limited to avoid excessively alkaline conditions, which can result in a UDC mechanism (caustic gouging), which destroys the protective oxide layer in the boiler or HRSG evaporator. The amounts of both sodium hydroxide and tri-sodium phosphate added to the cycle also have to be controlled to avoid an increase of carryover of these conditioning chemicals into the steam, possibly putting the superheaters and turbines at risk.

Boiler and HRSG evaporator treatments are critical to the overall reliability of HRSG plants as they control and influence not only the major tube failure mechanisms but also a number of damage mechanisms in the steam turbine.

PT – Phosphate Treatment [12]

For more than 25 years, consolidated good operating experiences worldwide have led to the recognition that tri-sodium phosphate (TSP) should be the only phosphate chemical added to an HRSG, and that the operating range should be bounded by a sodium-to-phosphate molar ratio of 3:1, a TSP level of 1 $mg \cdot kg^{-1}$ with a minimum of 0.3 $mg \cdot kg^{-1}$, and NaOH to give a pH above 9.0. This precludes addition of mono- and/or di-sodium phosphate and thus eliminates the possibility of acid phosphate corrosion [7]. It should also be emphasized that the 0.3 $mg \cdot kg^{-1}$ level is regarded as a minimum and that better protection will be afforded by operating at as high a level of phosphate as possible without exceeding the steam sodium limits.

CT – Caustic Treatment [12]

Caustic treatment (CT) can be used in HRSG drum-type boilers to reduce the risk of FAC where all-volatile treatment has proved ineffective, or where PT has been unsatisfactory due to hideout or has experienced difficulties of monitoring and control. The addition of sodium hydroxide to the boiler/evaporator water has to be carefully controlled to reduce the risk of caustic carryover into the steam, which could lead to damage of steam circuits and turbine due to SCC.

Summary and Basic Rules for the Cycle Chemistry Treatments for Combined Cycle/HRSG Plants

Based on IAPWS Guidance for combined cycle plants [3,10–16] and on the most recent understanding of the FAC mechanism [4], there are three basic simple guiding principles for optimizing the cycle chemistry and controlling FAC in combined cycle/HRSG plants:

a) An oxidizing treatment, AVT(O) or OT, must be used to prevent single-phase FAC [4]. No reducing agent should be used at any time during operation or shutdown of a combined cycle/HRSG plant. Use of AVT(R) in combined cycle/HRSG plants remains as one of the major incorrect chemistries still used worldwide. The situation is improving but still represents over 30 % of units worldwide reduced from about 70 % in the early 1990s: a major reason that single-phase FAC is still occurring.
b) An elevated pH25 with ammonia or an alkalizing amine is needed to control two-phase FAC (up to pH 9.8) [4]. For those combined cycle plants with an ACC it has been found that the operating pH will need to be close to 9.8 to arrest the FAC at the tube entries of the ACC in the upper ducts (streets) to prevent large levels of corrosion products (total iron) entering the HRSG [8]. Most recently FFS have been shown to arrest the FAC [4,10].
c) The total iron corrosion products should be monitored to compare with the IAPWS Guidance values of $< 2\ \mu g \cdot kg^{-1}$ in the feedwater and $< 5\ \mu g \cdot kg^{-1}$ in the drums [13]. This is one of the ways to verify that the chemistry is optimum, but as will be seen later, not making these measurements is the major deficiency (called Repeat Cycle Chemistry Situation (RCCS)) in control of the cycle chemistry of combined cycle plants worldwide.

Importance of the Analytical Tool of Repeat Cycle Chemistry Situations (RCCS)

Although the understanding of the cycle chemistry influenced failure and damage mechanisms in the steam/water circuits of combined cycle/HRSG plants is very advanced and has been known and documented for more than 30 years, chemistry influenced damage (Section 1.1) and the associated availability losses due to deficient chemistry practices remain enormous. The authors thought in the mid-2000s that it was clear that the cycle chemistry approaches taken by plants operating combined cycle plants were frequently unsuccessful. Further analysis in 2008 [17] of past cycle chemistry assessments and damage/failure investigations in over 150 organizations worldwide led to very interesting conclusions on why these damage/failures continued to occur. This involved identifying Repeat Cycle Chemistry Situations (RCCS), which can be regarded as the basics of cycle chemistry and are allowed to continue by the chemistry or operating staff or are imposed on the plant/organization as a consequence of inadequate management support for cycle chemistry.

From the viewpoint of organizational or management aspects of the cycle chemistry and its control, it became clear that every cycle chemistry failure/damage incident can be related backwards in time to multiples of RCCS which were not recognized or properly addressed and allowed to repeat or continue. In some cases, the chemistry staff had not recognized the importance of the situation and allowed it to continue. In other cases, the chemistry staff recognized the importance, but was not successful in convincing the management (either plant or executive) that action was required to eliminate the RCCS. In many cases the management has delayed action or has not provided the necessary funds to resolve the situation. In doing this type of retroactive analysis it very quickly became obvious that plants/organizations can get away with having one or two RCCS, but once this number increases then failure/damage is a certainty.

In 2008, the following original RCCS were identified which were very commonly associated with preventable cycle chemistry related damage in combined cycle plants:

- Management of corrosion products (such as non-measurement, incorrect technique, levels too high)
- Boiler/HP evaporator deposition (such as not measured, too high, possibility of under-deposit corrosion [5–7])
- Non-optimum chemical cleaning
- Contaminant ingress (with no reaction by the operators)
- Drum carryover
- High level of air in-leakage
- Lack of shutdown protection
- Inadequate on-line alarmed instrumentation
- Not challenging the status quo (such as using the same chemical treatment from original operation, out of date guidelines, no chemical manual for plant)

The categories remain the same, but it has become clearer that there are multiple sub-categories for each. This analysis has been used by the authors in all 90 combined cycle assessments and any root cause analyses to identify the cycle chemistry features responsible and which can be addressed through action planning. The results are discussed in Section 3.1. Trends which are very similar have been found by one of the authors in assessments of over 120 conventional fossil plants.

2.2 INTRODUCTION OF MAJOR FAILURE MECHANISMS IN COMBINED CYCLE/HRSG PLANTS

FAC in HRSGs

In combined cycle plants, FAC has been the leading cause of HRSG Tube Failures (HTF) over the last 20+ years and represents about 35–40 % of all HTF. Both single- and two-phase FAC can occur in LP and IP evaporators and LP, IP, and HP economizer tubing, but there are no reliable statistics to provide definition on the circuits. Two-phase FAC has also been a problem in LP and IP evaporator drum steam separation equipment and in the evaporator riser piping. The results from the large data base of assessments of combined cycle plants have allowed the authors to identify the typical systems susceptible to both single- and two-phase FAC in the results section of this paper (Section 4).

Recently a large technical review of FAC in generating plants was published [4] so only a few of the key aspects are included in this paper for understanding the mechanism and results of FAC in combined cycle plants. FAC is controlled by the oxide film that forms on the carbon steel surfaces and affords a barrier to diffusion. Dissolved iron species are transported from the surface to the flowing bulk fluid (water or two-phase steam/water). As the oxide dissolves into the water and is replenished by the metal oxidation, the film attains a steady-state thickness. The thicker and more compact the film, the greater is the barrier to diffusion and the more protective is the oxide and thus the lower is the FAC rate. Figure 1 shows a simple schematic of the mechanisms in terms of the chemical reactions and processes occurring within the oxide film under reducing conditions. The ferrous ions at the metal-oxide interface combine with the hydroxyl ions to form dissolved ferrous hydroxide, half of which decomposes oxidatively to magnetite to fill the volume of metal reacted and releases hydrogen molecules that diffuse towards the fluid. The other half diffuses through the oxide and is itself released to the bulk fluid. At the outer surface of the oxide the magnetite dissolves reductively to ferrous hydroxide at steady-state consuming exactly the amount of hydrogen produced by its formation at the metal surface. Conditions that increase the dissolution rate through chemistry by increasing the magnetite solubility and dissolution kinetics, and through fluid dynamics by increasing the mass transfer and remov-

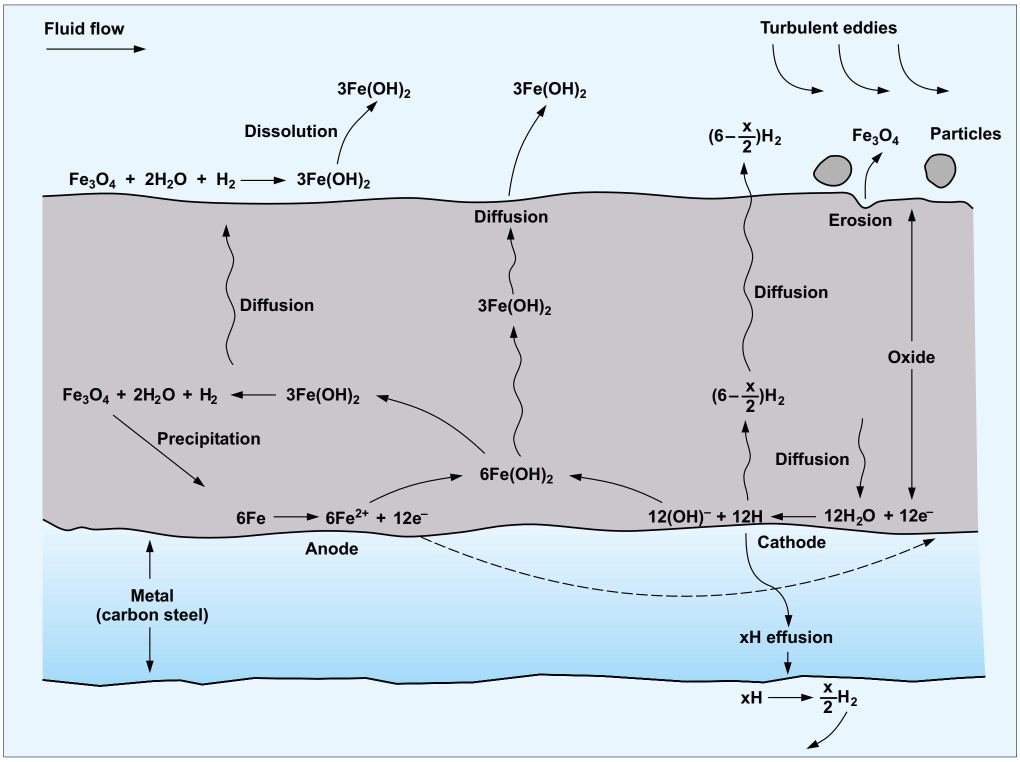


Figure 1:
Schematic of the mechanism of FAC at steady-state, showing the associated stoichiometrically balanced chemical reactions and transport processes [4].

al of dissolved iron from the surface, tend to thin the oxide and increase the transport processes, leading to increased corrosion and magnetite production at the metal surface until steady-state is resumed. The thinner the oxide, the faster is the FAC. Typical oxide films in single-phase feedwater systems are up to a micrometer or so thick, but under two-phase conditions around 150 °C can be a fraction of that, actually appearing as interference films (seen as black shiny surface). Increased turbulence from the HRSG geometry thins the fluid boundary layer and increases the mass transfer, in turn increasing the oxide dissolution and the FAC rate. The dissolution can promote the erosion or removal of oxide particles by fluid forces.

FAC in Air-Cooled Condensers (ACC)

Operating combined cycle units with ACC at the lower regimes of pH provided in the IAPWS Technical Guidance Document (TGD) [11] will result in serious corrosion/FAC in the ACC tubes, most predominantly at the entries to the cooling tubes in the upper ducting (streets) [4,8].

The cycle chemistry influenced FAC damage in ACC can be best described through an index for quantitatively defining the internal FAC status of an ACC. This is known by the acronym DHACI (Dooley Howell ACC Corrosion Index) [8]. This methodology was recently published as a guideline of the ACC Users Group (ACCUG) [9]. The index separately describes the lower and upper sections of the ACC. Examples from the recent FAC review [4] are included in Figures 2 and 3.

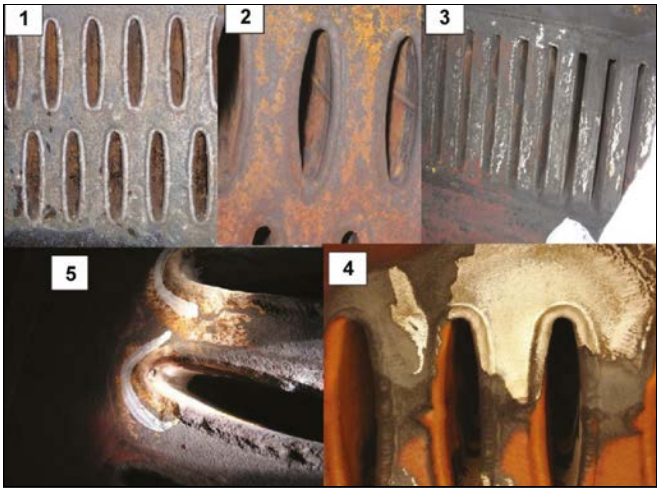


Figure 2:
Montage illustrating DHACI indices 1–5 for the upper ducts and tube entries of ACC. The FAC damage increases with number [4,8].

In the assessments conducted, the DHACI has been used to describe the status of a particular ACC, which is a useful confirmation of the chemistry and of FAC in the HRSG. It is also a very useful means of tracking changes that occur as a result of making changes in the cycle chemistry. For instance, a plant that has a relatively poor rating for FAC at a condensate cycle pH of 8.5–8.8 (e.g. with a DHACI of 4C) may increase the pH to 9.4–9.6 and determine whether this change improves its rating (e.g. to a DHACI of 3B). A poor rating indicates the need to consider options to reduce the FAC rate, especially at the tube entry areas and

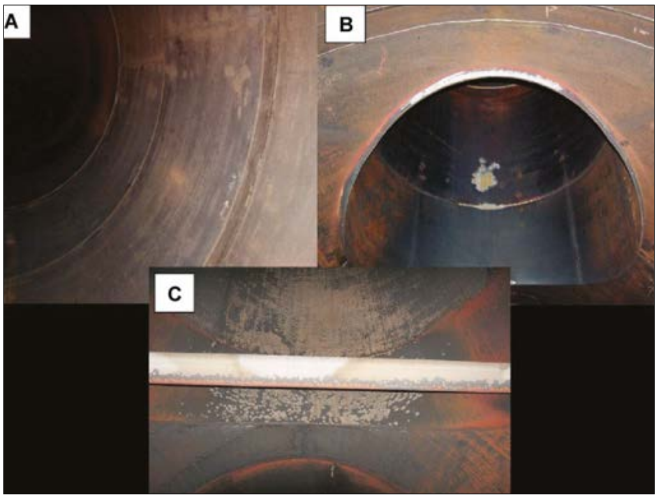


Figure 3:
Montage illustrating DHACI indices A–C for the lower ducts of ACC from the steam turbine to the vertical risers to the upper duct. Increasing letters indicate more severe and extensive damage [4,8].

at two-phase locations in the HRSG. The DHACI can also provide a qualitative indication of total iron corrosion products flowing from the ACC into the plant condensate. The index provides a convenient tool for comparison between different units and when alternative chemistries are used. For example, a number of plants worldwide have changed to the use of an FFS rather than, or supplementary to, ammonia, and by using the DHACI the improvements can be documented.

Under-deposit Corrosion in HRSG HP Evaporators

The three UDC mechanisms, hydrogen damage, acid phosphate corrosion, and caustic gouging, occur in HRSG HP evaporator tubing, and all require relatively thick porous deposits and a chemical (either a contaminant or non-optimized treatment) concentration mechanism within those deposits. UDC damage can occur early in the life of a plant due to the inverse relationship between deposit loading/thickness and the severity of the chemical excursion.

For **Hydrogen Damage (HD)**, the concentrating corrodent species is most often chloride which enters the cycle through condenser leakage (especially with seawater or brackish water cooling) and via slippage into demineralized makeup water in water treatment plants where ion exchange resins are regenerated with sulfuric or hydrochloric acid [5].

Acid Phosphate Corrosion (APC) relates to a plant using phosphate blends which have sodium-to-phosphate molar ratios below 2.6 and/or the use of congruent phosphate treatment using one or both of mono- or di-sodium phosphate [7].

Caustic Gouging (CG) involves the concentration of NaOH used above the required control level within caustic treatment, or with the use of coordinated phosphate with high levels of free hydroxide, or the ingress of NaOH from improper regeneration of ion exchange resins or condenser leakage (fresh water cooling) [6].

The UDC mechanisms of hydrogen damage and caustic gouging have been well understood in conventional fossil plants for over 40 years, and the acid phosphate mechanism since the early 1990s. Despite this, these mechanisms have become frequent problems worldwide in HRSGs. This may be because until recently the understanding of how the initiating deposition takes place in HRSG HP evaporator tubing has been less well understood than in fossil plants as well as the level of deposits necessary for these mechanisms to initiate by concentration within thick deposits. The IAPWS TGD [15] is based on deposit data from over 150 HRSGs worldwide and provides detailed information where to sample and how to analyze HRSG tubes for deposits and how to determine if the HRSG needs to be chemically cleaned.

2.3 INTRODUCTION TO THERMAL TRANSIENTS

Starting, stopping, and GT load changes result in unavoidable and repeated thermal transients in critical HRSG components. These transients in turn result in incremental accumulation of invisible, irreversible fatigue damage in these components during each thermal transient. The degree of fatigue damage occurring during each thermal cycle (heating/cooling) is dependent upon the size of the transient (ΔT) and the component's design details and material properties. The component's finite fatigue life is dependent on the degree of fatigue accumulation during each cycle and the number of cycles experienced. Once sufficient fatigue damage accumulates a crack is initiated and may grow through the component wall as additional cycles occur. If operating conditions limit the degree of fatigue damage and number of cycles to those anticipated by the designer, the component is fabricated as per design, and its material properties are correct, the component will operate successfully, relative to fatigue life, and no failure will occur during the design life of the HRSG.

While design issues and errant material properties occasionally influence fatigue failure, most are the result of larger and/or more frequent thermal transients than anticipated by the designer. These transients may result in fatigue accumulation due to excessive through-wall stress and/or restrained distortions (humping and hogging) in components such as the HP drum, HP superheater and reheater (HPSH/RH) headers and steam pipes, or restrained differential expansion between HPSH/RH tubes. The authors' experience suggests that most fatigue failures are caused by unidentified or unresolved operational issues resulting in the following:

Attemperator/desuperheater spray water leaking

- Attemperator overspray
- Insufficient draining of HPSH/RH condensate during startup
- Excessive HP drum pressure ramp rates
- Inappropriate operation of HP and HRH bypass systems
- Economizer inlet quench

These and other underlying causes of damaging thermal transients are discussed further in Section 5.

2.4 IMPORTANCE OF ROOT CAUSE ANALYSIS AND HRSG TUBE FAILURE (HTF) PROGRAMS

As in the original publication in 2009 [1], the authors continue to report from the assessments that it is very common for organizations to "assume" the mechanism and root cause of a unit's first tube failure to be something simple like "a bad weld." Sometimes operators conduct mechanism analysis by extracting tube samples, but do not conduct a detailed root cause analysis. But most often tube samples are not taken so the mechanism is not known, and failures continue until a large number have occurred. The authors have experienced up to 27 repeat HTF on an HRSG. In this case a tube sample for metallurgical analysis was only taken for HTF numbers 16 and 27. In many cases the actual root cause may be due to a cycle chemistry deficiency, design feature, or operating practice that has repeatedly inflicted corrosion, corrosion fatigue, or thermal-mechanical fatigue damage in the failed tube and its neighbors. For the cycle chemistry failure mechanisms this is most often due to plants continuing to operate with multiple RCCS. Six of the plants assessed had a program or policies in place that ensure the actual root cause will be determined when a failure occurs. Not surprisingly, over 60 % of the plants assessed have already experienced failures or display obvious symptoms of severe thermal transient damage in the superheater, reheater, or economizer. The only way to ensure that the corrective actions are taken and will prevent a tube failure from recurring is to remove the initial failure site, have the actual failure mechanism identified via a metallurgical laboratory analysis, and then determine the root cause of the failure. The authors have indicated to the plants assessed that taking the additional forced outage time to remove the failed section of tube is not a trivial matter. But it can easily be accommodated through a tube failure prevention program initiated before failures occur and when the unit is running well, not during the forced outage when the unavailability and lost revenue meters are running.

The authors always suggest to plants that to be proactive, and in preparation for future HTF, a management-supported tube failure prevention plan should be developed. Such a plan does not need to be complex, but should include the following key elements to be executed during any tube failure event:

i) There should be prior agreement, throughout the management chain, that a tube sample containing the failure site will be removed from the HRSG for metallurgical analysis so that the mechanism can be identified/confirmed;
ii) Root cause, as contrasted with failure mechanism, must be determined for each tube failure event;
iii) Each failure date, repair scope, and failure location within the HRSG must be precisely recorded using an unambiguous orientation scheme (failure site orientation (up/down, gas flow direction, position and orientation on tube of failure, etc. should also be recorded));
iv) A modest supply of spare HRSG tubing in appropriate sizes and materials, including a few bends, should be placed in inventory;
v) Action plans should also be developed for root causes of and damage by the HTF mechanisms which are most common in similar combined cycle plants.

3 KEY ASPECTS FROM THE ASSESSMENTS RELATING TO HRSG CYCLE CHEMISTRY

The understanding of cycle chemistry influenced FAC and UDC mechanisms in combined cycle/HRSG plants is very advanced and has been known and documented for more than 30 years. The latest understanding for the cycle chemistry of these plants is available in the IAPWS TGD [11,12], and the latest mechanism understanding for FAC and UDC has been published and is discussed in Section 2.2. The authors have found that the reason these failure mechanisms and non-optimization of the cycle chemistry continue to occur relates to plants allowing RCCS [17] to continue by the chemistry or operating staff or some of the RCCS are imposed on the plant/organization as a consequence of inadequate management support for cycle chemistry. In combined cycle/HRSG plants these plant assessments have confirmed that every cycle chemistry influenced failure, damage, and incident can be related backwards in time to multiples of RCCS which were not recognized or properly addressed and were allowed to repeat or continue. In many cases, the chemistry staff had not recognized the importance of the situation and allowed it to continue. In other cases, the chemistry staff recognized the importance, but was not successful in convincing the management (either plant or executive) that action was required. Also, it became obvious that plants/organizations can get away with having one or two RCCS, but once this number increases then failure/damage is a certainty.

3.1 THE RCCS CATEGORIES IDENTIFIED IN ASSESSMENT

In total there are ten RCCS [17], all of which are associated with combined cycle plants. The 90 assessments conducted by the authors at combined cycle plants worldwide indicate that there are multiple sub-categories. To assist the readers in understanding how RCCS influence damage/failure in combined cycle/HRSG plants, and whether they exist in their plants, the following provides a few notes on some of the most important RCCS categories.

Corrosion Products

Monitoring of total iron is the key indicator for optimizing the plant's cycle chemistry, and indirectly for FAC and UDC. The levels quoted in Section 2 provide an indicator of achievable levels in combined cycle/HRSG plants ($< 2\ \mu g \cdot kg^{-1}$ in feedwater, $< 5\,\mu g \cdot kg^{-1}$ in the drums) and in units with ACC ($< 5\,\mu g \cdot kg^{-1}$ in the condensate after a 5 micron absolute filter). Categories that were identified during the assessments include:

a) The corrosion product levels are not known or monitored;
b) The levels are too high and much above the international achievable values;
c) There are inadequate and/or not sufficient locations being monitored;
d) Sampling has been conducted at the same time/shift each time;
e) Techniques are used with incorrect detection limits;
f) A most common feature is monitoring only the soluble part of the total iron by not digesting the sample;
g) Steam/water sampling troughs need frequent cleaning (multiple times per year).

A key easy-to-observe verification aspect of this RCCS is observing black deposits in the steam and water sampling (wet rack) troughs for units on AVT(O). All of these categories are discussed in detail in the IAPWS TGD on corrosion products [13].

HRSG Evaporator Deposits

Corrosion products deposit on the inside surfaces of HRSG HP evaporator tubing and are an indirect indicator of corrosion and FAC in the lower temperature/pressure parts of the cycle. They are also a precursor to UDC. Categories that were identified during the assessments include:

a) HRSG HP evaporator samples have not been taken for analysis;
b) There is no knowledge of deposit levels and deposition rate in HP evaporators, even in plants with severe FAC;
c) Samples have been taken but not analyzed comprehensively;
d) Deposits are excessive and exceed criteria to chemical clean [15];
e) The HRSG HP evaporator deposits are not linked with chemistry in the lower pressure circuits or to the levels of transported total iron [13];
f) The HP evaporator has been sampled and needs cleaning, but management delayed or canceled.

For combined cycle/HRSGs all of these categories are discussed in detail in the IAPWS TGD [15], where a map is provided to determine if the HP evaporator needs chemical cleaning.

Continuous On-Line Cycle Chemistry Instrumentation

The IAPWS TGD [3] indicates the importance of the chemistry parameters in controlling FAC and UDC. Categories that were identified during the assessments include:

a) Installed and operating instrumentation are at a low percentage compared to IAPWS [3] (the assessments have indicated that an average value for plants is around 60 % compared to IAPWS, but 10 % of plants assessed had zero instruments working);
b) Too many instruments are out of service;
c) Plants don't have a maintenance or calibration schedule;
d) Instruments are not alarmed for operators in the control room and most often operators don't know and can't find the alarm levels;
e) There are no comprehensive procedures for operators in the event of an alarm;
f) Many instruments are shared at multiple locations and not/never switched;
g) The plant relies on grab samples to control the plant (for example 1 or 2 times per day, meaning that the plant is out of control for 12 or 24 hours, respectively).

Monitoring Drum Carryover

This RCCS is of primary importance for protecting the PTZ of the steam turbine in situations when contaminants enter the cycle. Any condenser leakage will immediately elevate the HP drum and HPSH chloride levels. This RCCS is linked with providing shutdown protection of the PTZ of the steam turbine to prevent pitting. Categories that were identified during the assessments include:

a) Carryover testing has not been conducted since commissioning;
b) No carryover testing is most often found when units have PTZ problems;
c) The plant is not aware of simple process (IAPWS TGD [16]);
d) Saturated steam samples are not working or are non-existent;
f) Samples for sampling saturated steam are often not isokinetic.

Monitoring Air In-Leakage

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 [11] and/or design specifications, is a common problem for combined cycle plants. It reduces both plant capacity and efficiency (productivity) and makes control of the cycle chemistry relatively more difficult. AIL often contributes to sub-cooling of the condensate and to increased concentrations of dissolved oxygen and other contaminants in the condensate. Categories that were identified during the assessments include:

a) Plants are not aware that effective control of AIL is essential to cycle chemistry optimization and to attaining the highest possible levels of plant generation capacity and efficiency;
b) Plants do not have an AIL team or program which includes items c) to f);
c) AIL is not measured/monitored by the operators;
d) The plant has not conducted a vacuum fall test;
e) Inert tracer gas such as helium has not been used to identify sources of AIL;
f) Correction of leak sources is not regarded as a high priority maintenance item.

It should be noted that there is recent international guidance from IAPWS [18] on AIL.

Shutdown/Layup Protection

This RCCS is multi-faceted and the lack of protection has led to serious pitting damage in HRSG drums and steam turbines. Categories that were identified during the assessments include:

a) There is no equipment (nitrogen or dehumidified air (DHA)) or chemistry for providing shutdown protection [14];
b) Plant doesn't recognize the main concerns: PTZ in LP turbine;
c) Equipment is present but not used or is inoperable/not maintained;
d) There are poor/no operator procedures;
e) Only partial protection is applied (boiler/HRSG vs feedwater);
f) There is no DHA for the steam turbine except on the newest plants;
g) FFS is not recognized as a possible protection, or an FFS is applied incorrectly and not following the IAPWS TGD [10].

Challenging the Status Quo

This RCCS is most important in ensuring that a plant operates with the latest cycle chemistry understanding, and that it has practices to arrest FAC and prevent UDC in plant cycles. Categories that were identified during the assessments include:

a) No change in chemistry since commissioning;
b) Using incorrect or outdated guidelines (very often plants don't know the origin of their guidance and how out of date it is);
c) Continuing to use incorrect chemistry such as AVT(R) and reducing agents (thus risking or experiencing single-phase FAC);
d) Continuing to use relatively low pH (thus risking or experiencing two-phase FAC);
e) Not having a comprehensive chemistry manual for the unit, plant, or organization (see Section 6.1 for an example);
f) Incorrect addition point for chemicals;
g) Not questioning the use of proprietary chemical additions (phosphate blends, amines, FFS) and therefore not knowing the composition of chemicals added to the unit/plant;
h) Not determining the optimum feedwater pH to prevent/control FAC through monitoring total iron.

3.2 KEY RCCS RESULTS AND RANKINGS IN COMBINED CYCLE/HRSG PLANTS ASSESSED

The RCCS analysis has been applied during all 90 combined cycle HRSG plant assessments. Table 1 shows the most recent ranking of the RCCS for these plants, and essentially provides an indication of the major deficiencies in

RCCS Category	Combined Cycle/HRSG Plant [%]
Corrosion products	93 ↑
Fossil waterwall/HRSG evaporator deposition	63 ↑
Chemical cleaning	< 10 =
Contaminant ingress	< 10 =
Drum carryover	90 ↑
Air in-leakage	< 10 ↓
Shutdown protection	61 ↓ (& 92*)
On-line alarmed instrumentation	95 ↑
Not challenging the status quo	83 ↑

Table 1:
Repeat Cycle Chemistry Situations (RCCS) in 90 combined cycle/HRSG plants. The numbers in the table represent the percentage of plants where the particular RCCS was identified and the arrow indicates the trend.
* percentage of plants not using dehumidified air (DHA) on steam turbine during shutdown

cycle chemistry treatments and controls which continue to result in damage/failure as outlined in Section 2.2. Alternatively, for plant operators and chemists who want to be on the path to world-class performance, this table provides the most important cycle chemistry aspects which need to be addressed to ensure they avoid future cycle chemistry influenced damage/failure. Table 1 indicates that the most common deficiencies in combined cycle plants worldwide are related to continuous instrumentation and monitoring corrosion products. All the items related to a plant challenging the status quo are also prolific in not being identified or addressed. The table can also be used to identify the major RCCS responsible for why the main damage and failure mechanisms continue to occur:

a) Flow-accelerated corrosion (FAC): corrosion products, challenging the status quo, instrumentation;
b) Under-deposit corrosion (UDC): corrosion products, HP evaporator internal deposits, challenging the status quo, instrumentation, canceling/delaying chemical cleaning;
c) Steam turbine phase transition damage/failure: repetitive contaminant above action/shutdown level, instrumentation, drum carryover, shutdown protection (especially lack of DHA), corrosion products, challenging the status quo.

This illustrates clearly why these three major failure/damage mechanisms continue to occur despite the excellent understanding of the mechanisms, the well documented locations, and the availability of the comprehensive IAPWS cycle chemistry guidance. The arrows on Table 1 note the approximate trends over the last five years.

A final note on RCCS is that each one identified should be eliminated as soon as possible. The authors usually suggest an action plan and a time frame (see additional discussion in Section 6.1).

4. KEY ASPECTS FROM THE ASSESSMENTS RELATING TO HRSG FLOW-ACCELERATED CORROSION

4.1 APPROACHES TO IDENTIFYING AND ARRESTING FAC IN HRSGS

Controlling and Monitoring FAC

As for the cycle chemistry control there were some important observations emanating from the assessments about FAC and how it is controlled in HRSG plants. Some of the most important include:

- Despite IAPWS Guidance clearly indicating that only oxidizing treatments should be used in combined cycle plants, reducing agents continue to be used in about 35 % of plants;
- As reported in the RCCS section, only ~ 30 % of plants thought they "knew" the iron levels in condensate/feedwater and only ~ 20 % thought they "knew" the iron levels in the drums;
- Most iron measurements if made were only measuring soluble iron without any digestion and using the spectrophotometer in the chemistry laboratory;
- Only ~ 20 % had conducted inspection/non-destructive examination for FAC, but only in the cases where damage and failure had already occurred!
- Most plants addressed single- and two-phase FAC at the same time from a chemistry perspective, and as reported next there is still a lot of misidentification of single- and two-phase FAC.

Identification of FAC

It is most important to identify the type of FAC correctly because the cycle chemistry solution to arrest single-phase FAC (use of oxidizing treatments) is quite different to that for two-phase FAC (use of elevated pH up to 9.8). The key surface features for FAC were detailed in the recent FAC review [4] and because of the importance of identifying FAC from surface (visual) features some of this discussion is repeated here. If these surface features are linked with the location of the FAC (next sub-section), then it should always be possible to identify the correct type of FAC occurring in the HRSG.

Figure 4 provides two examples of the typical surface appearance of single-phase FAC in fossil and combined cy-

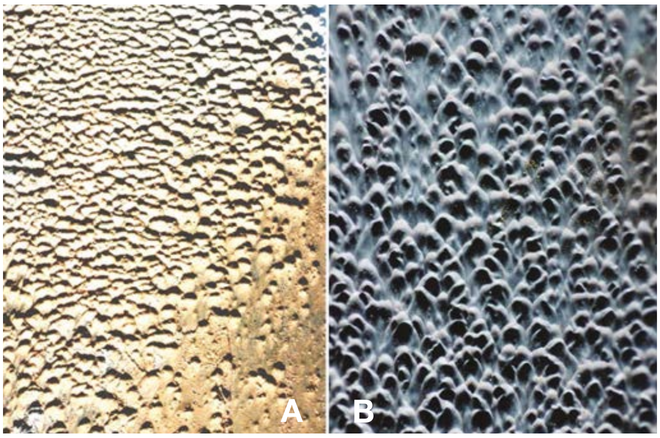


Figure 4:
Two views of the visual surface appearance of single-phase FAC. A is a typical detail from an economizer inlet header tube in a conventional fossil plant. Example B is a similar view from the FAC surface near to the inlet of an HRSG LP evaporator tube. In both cases the horseshoes or chevrons point in the direction of flow (bottom to top) [4].

cle/HRSG plants. In locations where single-phase FAC is starting, such as towards the bottom of photograph A in Figure 4, individual horseshoes or chevrons can be clearly seen and always point in the direction of flow (bottom to top in photograph). As the turbulence becomes greater downstream of the flow disruption and the FAC rate increases, such as towards the middle/top of photograph A in Figure 4, the chevrons overlap and produce the typical orange peel appearance of single-phase FAC.

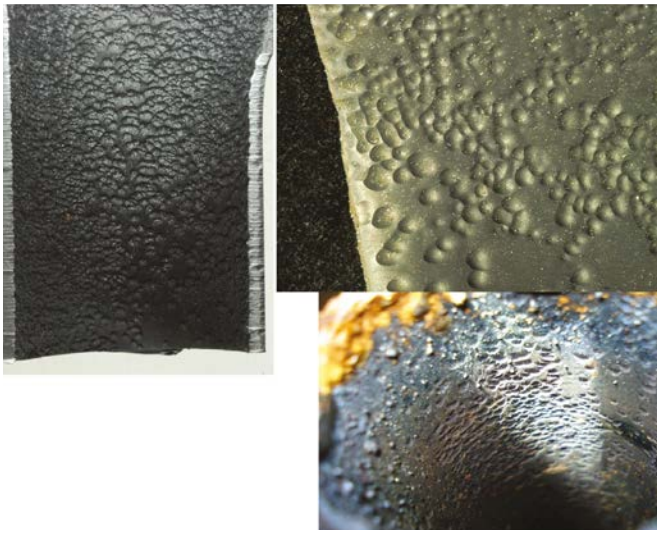


Figure 5:
Three examples of two-phase FAC in HRSG LP evaporator tubing. The left-hand photograph shows the typical black/shiny appearance of established FAC. The top right photograph shows the distinct dimples of initiating FAC without any obvious directionality in respect to the flow. The lower right shows a view looking into a LP evaporator tubing from the outlet header with severe FAC (failure) on the left side of the photograph and initiating damage on the right [4].

Figure 5 provides three examples of two-phase FAC in HRSG LP evaporators where the surface appearance of two-phase damage can be easily seen to be different to that in single-phase situations. This two-phase FAC damage is probably the most misidentified FAC in combined cycle/HRSG plants. This is most important because increasing the oxidizing power of the fluid will have no effect on the damage [4]. Established two-phase FAC always has a black shiny appearance (left photograph) and in areas where it is just starting or at the extreme of the damage there are often "dimples," which are usually misidentified as damage from pitting corrosion on the surface (top right photograph). They most often do not show any directionality like the chevrons of single-phase FAC. As the turbulence becomes established and the FAC wear rate increases, the dimples overlap and sometimes the surface appearance then resembles single-phase FAC (as seen in Figure 4) but is black and shiny.

Locations of FAC in HRSGs

The typical locations of FAC were originally compiled from the authors' assessments conducted up to the first paper [1] and were published in the 2008 FAC review [19] and in Chapter 15 of the HRSG Book [20]. Based on the 90 plants supplemented with separate studies on FAC in combined cycle plants, the predominant locations have been updated in Table 2. This table along with the surface appearances of both types of FAC should help the reader/operator identify the correct solution direction to take.

4.2 OPTIMUM APPROACHES FOR FAC IN HRSGS

Based on the surface appearances and the locations of FAC from the last sub-section, the following represent the authors' opinion on how FAC should be addressed in combined cycle/HRSG plants. These same points are of course directly applicable to optimizing the cycle chemistry for these plants.

- First, as already discussed in Section 2.1, there are three basic guiding principles for optimizing the cycle chemistry and controlling FAC and UDC:
    a) An oxidizing treatment AVT(O) or OT must be used to prevent single-phase FAC. No reducing agent should be used at any time during operation or shut down;
    b) An elevated pH 25 with ammonia or an alkalizing amine is needed to control two-phase FAC (up to pH 9.8);
    c) The total iron corrosion products should be monitored to compare with the IAPWS Guidance.
- The locations of single-phase FAC can be controlled by feedwater and evaporator chemistry. Multi-pressure HRSGs should operate only on an oxidizing cycle (AVT(O)) without any reducing agents. This decision should preferably be made during the specification/design stages of an HRSG, but if this stage has been missed, then the change should be made as early in the life of an HRSG as possible.
- Two-phase FAC of IP and LP evaporator tubing and other locations can be addressed by evaporator chemistry by operating at high pH levels with ammonia or an amine or by adding either tri-sodium phosphate or NaOH to the LP drum provided that the LP drum doesn't provide feed for upper pressure HRSG circuits or superheater/reheater attemperation.
- Two-phase FAC should be addressed during design by a materials solution (use of T/P 11 or 22). If obvious susceptible tube locations can be identified, then these should be replaced by a 1.25 % chromium (Cr) or higher alloy if the cycle chemistry cannot be optimized to arrest FAC. Ideally the susceptible locations should be designed with the chromium containing materials. Steam separating equipment in the LP/IP drums and

the LP/IP risers should also be designed or replaced with at least a 1.25 % Cr steel.

- Monitoring of iron in the feedwater and LP drum will identify whether FAC is active. Satisfying the "rule of 2 and 5," where the total iron level is consistently less than 2 $\mu g \cdot kg^{-1}$ in the feedwater and less than 5 $\mu g \cdot kg^{-1}$ in each drum, will provide an indication that FAC is not active.
- For multi-pressure HRSGs the level of deposits in the HP evaporator provides an indirect confirmation that the total iron levels in the lower pressure HRSG circuits are within the "rule of 2 and 5."
- Removal of HP evaporator tubing and analysis of the deposit levels also provides an indication of the risk for under-deposit corrosion by comparing the deposit levels with the IAPWS Map [15]. This will also provide an indication of whether there is a need for chemically cleaning the HRSG.
- Combined cycle plants with an ACC are a special case. Monitoring of the iron levels at the condensate pump discharge provides the important indicator of the extent and activity of FAC at the tube entries in the upper ducting. Worldwide experience indicates that a condensate pH of close to 9.8 will be required. Total iron corrosion product levels should be in line with the IAPWS Guidance (less than 5 $\mu g \cdot kg^{-1}$ in the condensate downstream of the condensate filters (5 μm absolute preferred)).
- There is an increasing data base showing that use of an FFS provides similar two-phase protection in the HRSG and ACC to a high pH level. Single-phase FAC in the HRSG can also be addressed. However, the most important observation from the authors is that following Section 8 in the IAPWS Guidance will ensure optimum results [10].

Single-phase FAC
LP economizer/preheater (feedwater) tubes at inlet headers (SA 178A, SA 192, and SA 210C tubing; SA 106B headers; 40–150 °C, 105–300 °F)
LP evaporator inlet headers with a tortuous fluid entry path or with any orifices installed (SA 106B; 130–170 °C, 260–340 °F)
IP and HP economizer inlet headers (SA 106B; 60–100 °C, 140–210 °F)
IP evaporator inlet headers (SA 106B) with a tortuous fluid entry path or with any orifices installed (210–250 °C, 410–482 °F)
Piping around the boiler feed pump. Includes SH and RH desuperheating supply piping

Two-phase FAC
LP outlet evaporator tubes on horizontal gas path (HGP) units (SA 192, SA 178A, and SA 210C; 150–165 °C, 300–330 °F)
Horizontal LP evaporator tubes on vertical gas path (VGP) units especially at tight hairpin bends (SA 192; 150–160 °C, 300–320 °F)
Economizer/preheater tube bends in regions where steaming takes place with particular emphasis being given to the bends closest to the outlet header (SA 178A, SA 192, and SA 210C tubing; SA 106B headers; 40–150 °C, 105–300 °F) (Note: Steaming can easily be identified in these areas by installation of thermocouples on the appropriate location.)
IP/LP economizer outlet tubes (SA 178A, SA192, SA 210C tubing; SA 106B headers; 130–150 °C, 260–300 °F)
HP economizer tube bends in regions where steaming takes place with particular emphasis being given to the bends closest to the outlet (SA 210 A1 and C tubing; ~ 160 °C, 320 °F)
LP evaporator link pipes and risers (SA 106B; 150–165 °C, 300–330 °F)
LP drum internals (belly plates in line with riser entries)
IP economizer outlet tubes with bends (SA 178A, SA192, SA 210A1 and C) and headers (SA 106B and C) (210–230 °C, 410–445 °F) if there is evidence of steaming
IP outlet evaporator tubes (SA 178A, SA 192, and SA 210C; 230–240 °C, 445–465 °F) on triple-pressure units especially if frequently operated at reduced pressure
IP outlet link pipes and evaporator risers (SA 106B) to the IP drum (230–240 °C, 445–465 °F)
Reducers on either side of control valves
Turbine exhaust diffuser
Air-cooled condenser tube entries in upper ducts (streets)

Table 2:
Locations of FAC in combined cycle/HRSGs [1, 4] (typical tube and header materials, and range of operating temperatures).

5 KEY ASPECTS FROM THE ASSESSMENTS RELATING TO HRSG THERMAL TRANSIENTS

Twenty-five years ago when the first F-class HRSGs came into service many of the drivers of thermal fatigue damage were not recognized as risks by HRSG OEMs, engineering, procurement, and construction (EPC) contractors, and ancillary equipment suppliers. For example, few HRSG OEMs imagined that condensate would form in the HPSH and RH during startup. Therefore, few

HRSGs were equipped with HPSH/RH drain systems intended to be opened during operation. These drain systems typically utilized 25.4 mm (1 in) HPSH/RH drain pipes and in some cases discharged directly to atmosphere rather than into a blowdown system. Because the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, to which most HRSGs are/were designed, does not require the HRSG OEM to perform fatigue analyses during the design process, few early HRSG designs included fatigue life assessments. Most early HRSGs were anticipated to operate in base load service, so few designs considered the impact of transient operations such as startup and shutdown. Likewise, many units suffered unnecessary and damaging thermal transients due to unthoughtful operating practices and procedures. The result of all this was that many HRSGs suffered premature pressure part failures.

Beginning in 1998 Bob Anderson (then with Florida Power Corporation, USA), with the aid of J. Michael Pearson and Associates (Canada) and based upon work initially performed by John Jesson of Mitsui Babcock, UK, began the process of installing large numbers of thermocouples (240–600 per HRSG) on tubes, pipes, and headers in Florida Power Corporation's (later Progress Energy's) new fleet of F-class HRSGs. Thermocouples were installed in HRSGs from four different OEMs. The findings resulting from analysis of the data collected during all modes of operation were published [21–25] and formed the basis for much of what is now known about thermal transients in HRSGs.

By 2009, when the first version of this paper was published [1], the thermal transient related damage mechanisms and their underlying causes prevalent in HRSGs were well understood by the authors and most were included in that paper. Most HRSG OEMs, EPC contractors, and ancillary equipment suppliers had by then learned to avoid some previously used undesirable design features and performed some kind of fatigue life assessment of key components when designing newer HRSGs. Due to repeated failures many owners have modified some of the worst features in older units. Some of these include:

- Replacing attemperators with the spray control valve located inside the nozzle support mast with hardware using an external control valve;
- Replacing simple feedback loop attemperator controls with cascade control logic;
- Modifying rigidly supported HPSH/RH modules to add spring supports for increased flexibility between harps;
- Separating common lower HP/IP economizer headers that used a partition inside the header into separate lower HP and IP headers;
- Replacing LP preheater inlet harps that contained tube bends;
- Replacing 25.4 mm (1 in) HPSH/RH drain pipes with larger pipe sizes;
- Bypassing elevated blowdown tanks with atmospheric low point HPSH/RH drains for use at low pressures.

Since 2009 thermal transient surveys have been performed on an additional 45 combined cycle gas turbine (CCGT) plants. Unfortunately, many of the avoidable causes of damaging thermal transients identified in 2009 continue to be common findings in these later surveys. Some of the design weaknesses and non-optimum operating procedures still in use by some include:

- Insufficient straight steam pipe length downstream of attemperator spray nozzle – particularly in RH attemperators;
- Lack of attemperator protective logic that prevents spraying when dangerous to pressure parts;
- Attemperator spray block and control valve protective logic that results in spray water leaking into hot pressure parts;
- Operating procedures that utilize the interstage attemperators too early in startup and during shutdown;
- Operating procedures that utilize the interstage attemperators to achieve excessively low HPSH/RH outlet steam temperatures when starting the steam turbine;
- Attemperator control and/or protective logic incapable of avoiding overspray;
- Permitting operators to manipulate attemperator setpoints;
- Permitting operators to manually control attemperator spray valves;
- HPSH and RH drain system arrangements incapable of providing complete draining during startups initiated from both low pressure and high pressure;
- HPSH and RH drain system operating procedures that fail to provide complete draining during all startups;
- Overly aggressive decrease and/or increase in HP drum pressure resulting in cracking of the downcomer to drum shell weld.

A couple of the drivers of thermal transients predicted to result in pressure part failures in 2009 have not done so. These include:

- Cracking in HPSH outlet headers and their tube connections due to overly aggressive steam temperature ramp rates;
- Failure of hairpin economizer tubes due to support load transfer when air or steam trapped in the unvented hairpins blocks water flow in individual tubes.

A failure mechanism that has become common in recent years but was not noted during the earlier work is erosion of the HP steam turbine bypass pressure control valve cage, disc, and seat by wet steam and water.

5.1 HOW TO IDENTIFY DAMAGING THERMAL TRANSIENTS

It was necessary to install thermocouples on tubes in the HRSG to identify damaging thermal transients during the late 1990s when little was known about the underlying causes. Today identifying avoidable thermal transients is typically accomplished by informed review of equipment design and operating data collected by the DCS. In a few cases additional thermocouples must be installed to supplement the normal DCS instrumentation, but these are typically placed in key locations on the exterior of piping external to the HRSG casing. A summary of the most common underlying causes of failures driven by avoidable thermal transients and how to identify them follows.

Leaking Attemperator Spray Water

Spray water leaking past the block and control valve remains a very common finding during thermal surveys. Of 54 CCGT plants evaluated, 82 % have leaking attemperators as demonstrated by DCS data plots. Small to moderate leakage rates have no noticeable impact on thermal performance, so may seem unimportant and not be taken seriously by many operators. However, even a small leakage rate into hot steam pipes during periods of zero and low steam flow causes cracking of thermal liners, at the inner surface of steam pipes and in girth welds. When cooler water contacts the bottom of a hot pipe, a top to bottom temperature differential occurs. This results in transient and/or permanent steam pipe distortion that can result in unanticipated piping system loads, cracking in girth welds, and damage to the pipe's support system. These distortions may cause water to flow away from rather than toward the drain and trap water in undrained low points. Trapped water will later be swept by steam flow into other sections of piping, tubes, and headers. Figure 6 presents plots of DCS data showing evidence of attemperator spray leaking.

Spray water valves are exposed to the severe duty of frequent opening and closing against high differential pressure. If the sequence of block valve and temperature control valve (TCV) opening and closing is not consistently controlled via well thought out protective logic, then spray water leaking can be expected. Many attemperators use Master Control/Martyr Block spray valve logic. With this logic the control valve opens first and then the block valve

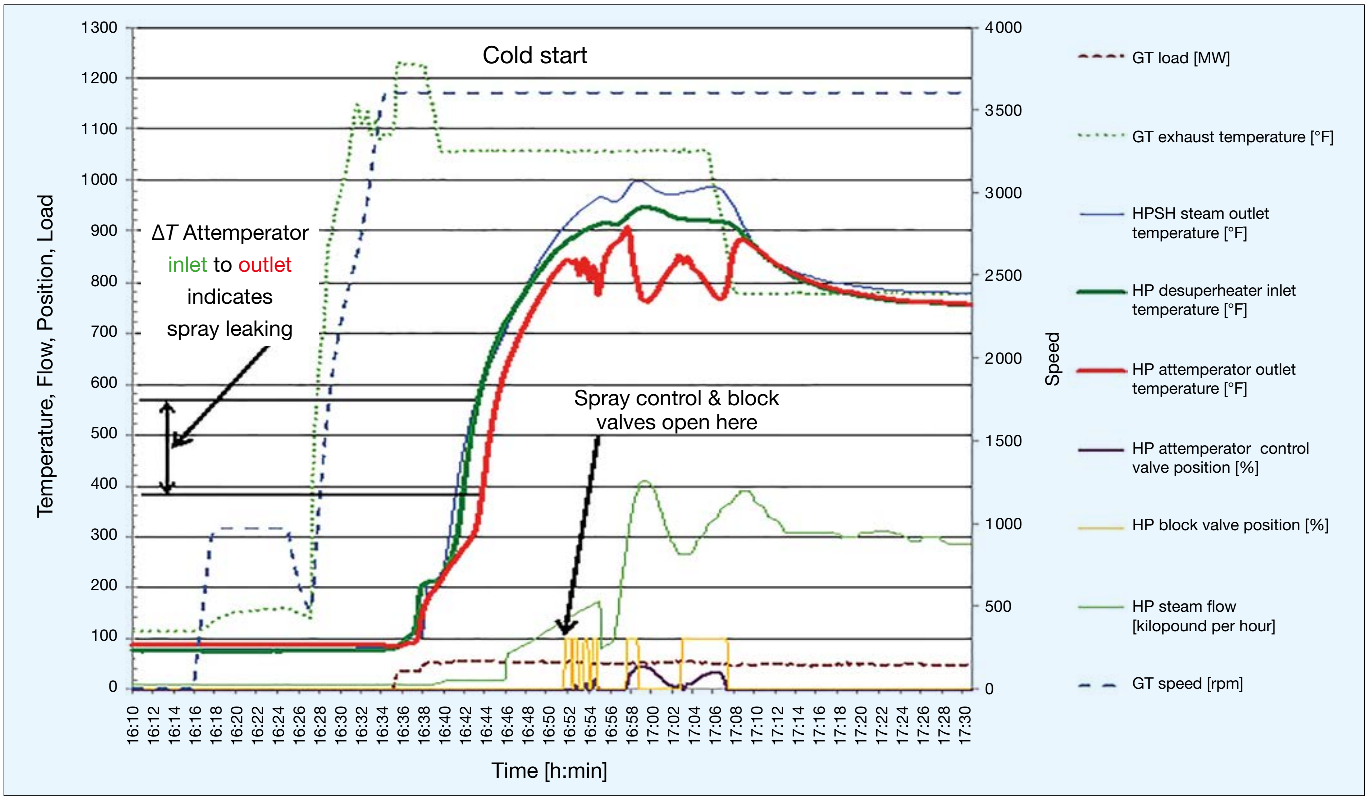


Figure 6:
Steam temperature difference between attemperator inlet (green line) and outlet (red line) during early startup with attemperator spray valves (orange and purple lines) closed indicates leaking spray water valves.

In Figures 6, 7, 8, 10, 11, 12, 16, and 17, SI units are not used consistently. Conversion rates:
$T_{(°C)} = (T_{(°F)} - 32) \times 5/9$; $f_{(s^{-1})} = f_{(rpm)} \times 60$; $P_{(bar)} = P_{(psi)} \times 0.068\,947$; $\dot{m}_{(kg \cdot s^{-1})} = \dot{m}_{(kilopound\ per\ hour)} \times 0.012\,599$.

opens when starting the attemperator. When stopping the attemperator the block valve closes first and then the control valve closes. This sequence results in the block valve opening and closing against high differential pressure, "martyring" its seating surfaces in an attempt to protect the control valve's seating surfaces. This sequence occurs each time the attemperator starts and stops, resulting in many open/close cycles on the block valve. Once the block valve's seat is damaged, the control valve's seating surfaces are now exposed to opening and closing against high differential pressure and also become damaged – now both valves leak. In the authors' experience, Master Control/Martyr Block valve logic is a major cause of attemperator leaking. Of 54 CCGT plants evaluated 95 % use Master Control/Martyr Block valve logic and 82 % have leaking attemperators. Figure 7 presents plots of DCS data showing evidence of the damaging valve action associated with Master Control/Martyr Block valve logic.

Attemperator Overspray

Overspray occurs when the attemperator injects more water into the stream of steam than can be evaporated prior to its arrival at the first downstream elbow or tee fitting. Best practice dictates that a minimum of 27.8 °C (50 °F) superheat is always maintained at the attemperator outlet. This margin is to ensure that unmeasurable and unpredictable water/steam mixing behavior does not result in damaging thermal transients in downstream pipes, headers, and tubes. Overspray produces severe thermal fatigue damage and cracking in downstream pressure parts. Figure 8 presents the same plots of DCS data in Figure 7 but noting evidence of attemperator overspray.

Overspray can result from design and/or equipment issues such as a steam pipe downstream of the attemperator that is too short to permit sufficient time for spray water to evaporate before reaching the thermocouple, defective spray nozzles producing overly large or misdirected water droplets, and HPSH/RH arrangements with so much secondary heating surface such that overspray occurs if secondary HPSH/RH outlet steam temperatures are limited to rated values during startup and low GT load operation. Overspray can also result from poorly designed/maintained attemperator control logic, manipulation of outlet steam temperature setpoint by operators, and manual manipulation of the spray control valve by operators. A very dangerous cause of overspray is operators using the interstage attemperator to achieve the very low (371 °C (700 °F)) HPSH/RH outlet steam temperatures required to roll, accelerate, and warm the steam turbine during startup. Regardless of the rationale for doing so, manual manipulation of the steam outlet temperature setpoint, and even worse, manual manipulation of the spray control valve more often than not will result in overspray.

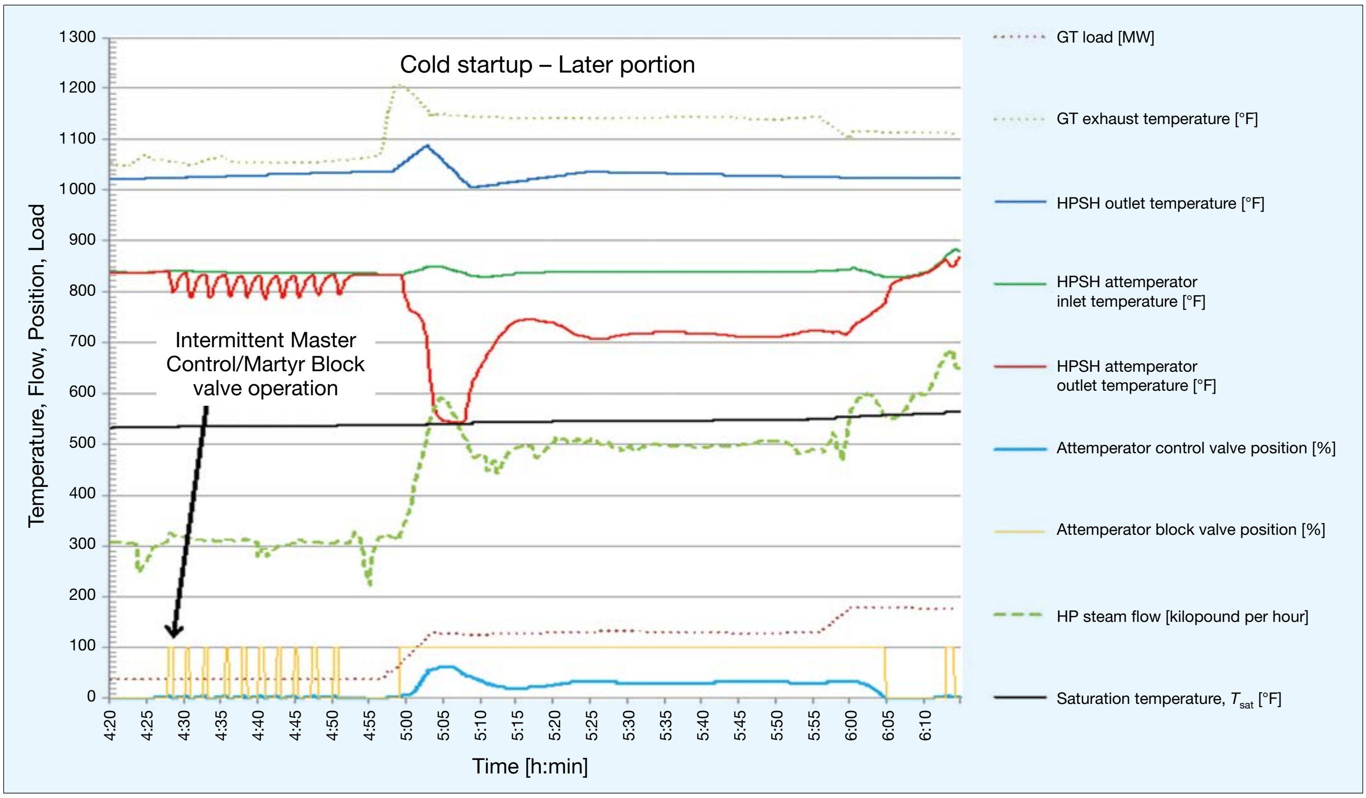


Figure 7:
The spray control valve (light blue line) opens first, then the block valve (orange line) opens each time spray is required. The process reverses each time spray is no longer required. This activity rapidly damages the block valve seating surfaces.

Attemperator Operation When Inappropriate

Like leaking spray water, operation of the attemperator during periods of low or zero steam flow when pipes, headers, and tubes are hot causes accelerated fatigue accumulation in these components. Unlike leaking spray water and overspray, which typically only cause invisible, cumulative damage that eventually results in failure, operation of the attemperator when steam flow is low or zero and pipes are hot has occasionally been known to result in immediate tube failure due to ductile overload. Figure 9 shows a photo of such a failure.

More frequently, operation of the attemperator too early in the startup and too late in the shutdown when steam flow is low, manual manipulation of outlet steam temperature and/or attemperator outlet temperature setpoints, and inappropriately using the interstage attemperator to match outlet steam temperatures for startup of the steam turbine result in eventual cracking in steam pipes and/or HPSH/RH tubes. The latter cause, using the interstage attemperator in an attempt to achieve unreasonably low steam outlet temperatures during steam turbine startup, often results when operators fail to use available means of lowering GT exhaust temperature such as the exhaust temperature matching feature in the General Electric Company (GE), USA, 7/9FA GT controls during cold lag, warm, and hot starts.

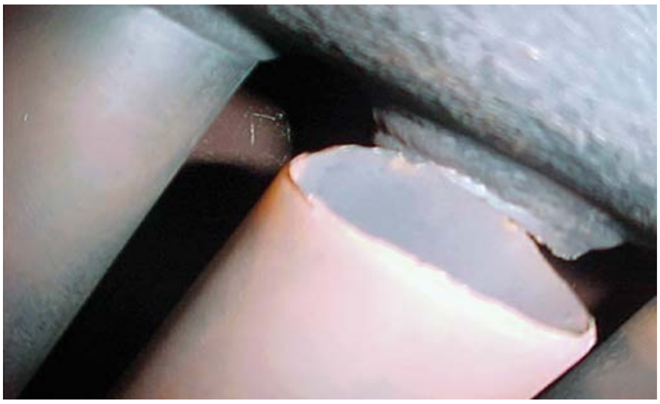


Figure 9:
HPSH tube pulled from its header due to manual operation of the attemperator following shutdown.

Failure to Adequately Drain the HPSH/RH during Startup

Condensate forms in the HPSH and sometimes in the RH whenever the gas path temperature is lower than the prevailing saturation temperature (T_{sat}) of water vapor inside the HPSH or RH tubes. Large quantities of condensate form in the HPSH (on the order of 3 000 kg (6 600 lb)) during the prestart purge prior to hot startups. Lesser quantities form in the HPSH during startups from lower temperatures. Leaking attemperator spray water during layup can add to the quantity of water to be drained during startup. It

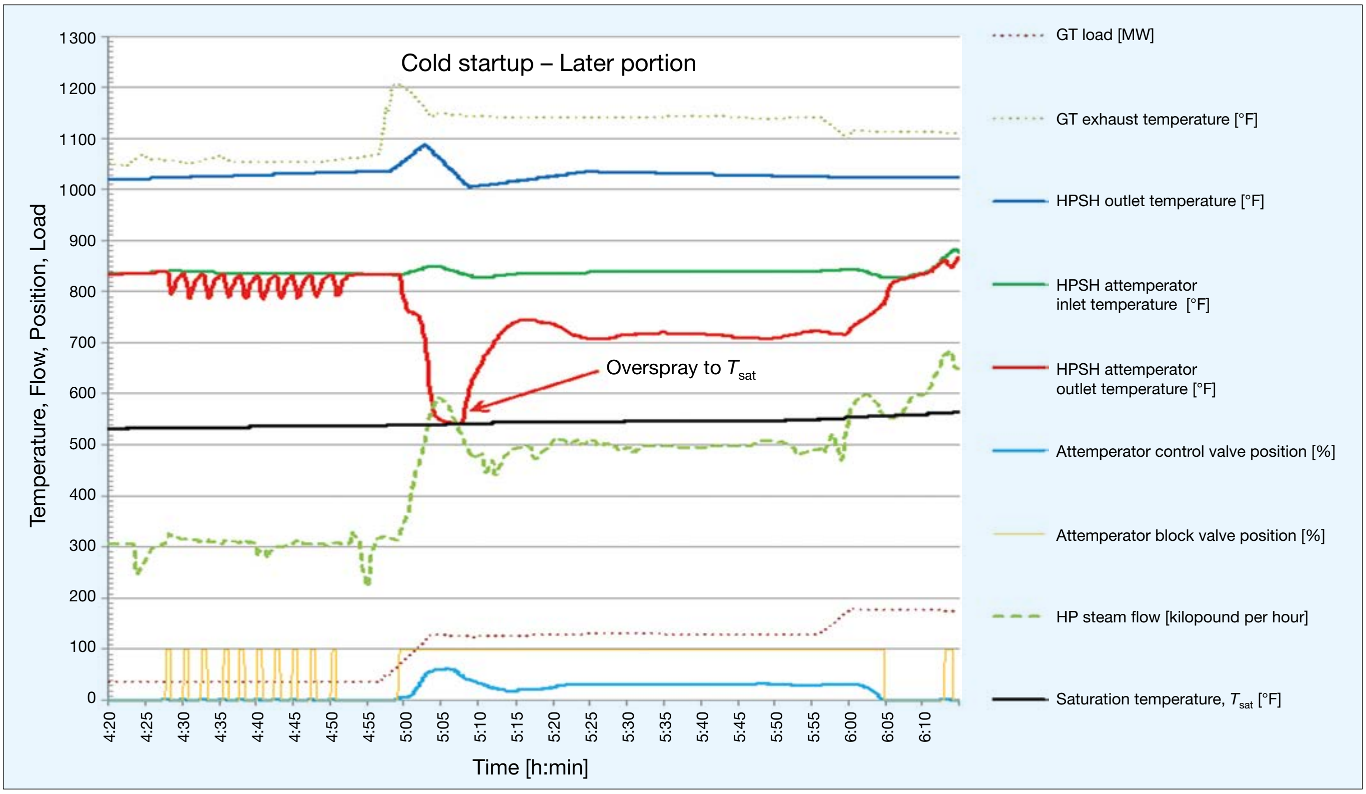


Figure 8:
Steam temperature at a thermocouple downstream of attemperator outlet (red line) dropping to T_{sat} (black line) indicates overspray.

is critical that this water be drained completely prior to initiation of steam flow in the HPSH and RH. During all types of startups HPSH and RH tubes heat up to near exhaust gas temperature (EGT) between GT light off and establishing initial steam flow through the tubes. Undrained water will migrate selectively through some tubes as steam flow is initiated, quenching (and shrinking) these tubes. Severe quenching sometimes results in global yielding of the tube, thereafter evident as buckling out of line when the transiently quenched tubes return to the same temperature as other tubes in the same row. After shutdown, headers, manifolds, and steam piping remain hot for long periods. During hot starts much cooler water remaining in the HPSH and lower piping is moved upward when steam flow is established and enters the still hot upper headers, collection manifolds, and steam piping. Figure 10 presents plots of DCS data showing evidence of water migration.

Failure to adequately drain water from the HPSH/RH during startup is sometimes caused by design issues such as drain pipes that are too small and/or too few to remove the water rapidly enough, are sloped uphill in the direction of flow, and/or discharge to a blowdown tank located at an elevation above grade. In some cases where drain design is adequate, poor draining is caused by ineffective manual or automatic drain valve operating procedures.

Aggressive HP Drum Pressure Ramp Rates

Due its relatively thick walls the HP drum requires limitation of temperature ramp rates to achieve its design life. The HP steam drum's fatigue life consumption establishes the maximum permissible HP drum pressure ramp during startup and shutdown. After initial heating to 100 °C (212 °F) during startup, the HP drum ramp rate is primarily controlled by HP and HRH bypass and startup vent capacity, bypass pressure ramp curves, and bypass pressure setpoint. GT load and EGT (via exhaust temperature matching with GE GTs) can provide a secondary influence.

During startup and other periods where pressure is increasing, pressure stresses at the drum's inner surface are tensile (positive) while thermal stresses are compressive (negative). During periods when pressure is decreasing both pressure and thermal stresses are tensile. Therefore, total stress when increasing pressure is lower than when decreasing pressure. This results in lower HP drum temperature ramp rate limits when depressurizing than when increasing pressure.

Drum ramp rate limits are typically expressed as a T_{sat} rate. This is because change in T_{sat} is non-linear across the HP pressure operating range. Repeatedly cycling the drum near or beyond the maximum permissible ramp rate is likely to result in cracking of the protective magnetite layer, followed by corrosion fatigue cracking of the underlying steel. This cracking is most likely to occur at the toe

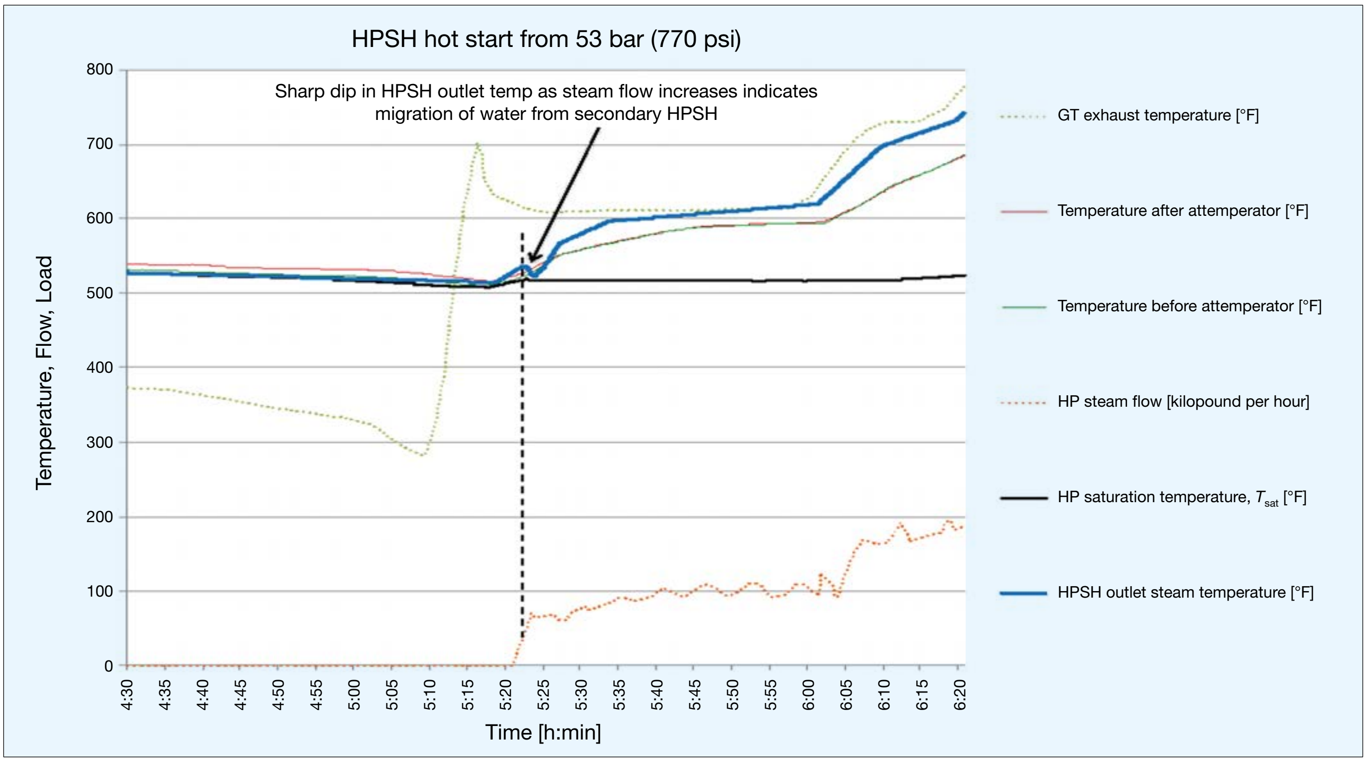


Figure 10:
Sharp dips in steam temperature when steam flow increases indicates migration of undrained water.

of the drum shell-to-downcomer weld on the interior of the drum. Cracks can also form at other nozzles in the drum. Shallow cracks can often be successfully ground out to reduce localized stresses, then periodically monitored for reoccurrence. If cracks in the drum are permitted to reach depths where weld repair is required, the welding and post-weld heat treatment logistics are very expensive and time consuming. If deep cracks are found in a drum there is the possibility that drum could be condemned until suitable life assessment and/or repairs are completed. Figure 11 presents plots of DCS data showing evidence of overly aggressive HP drum ramp rate during startup.

The ≈ 11 °C · min^{-1} (20 °F · min^{-1}) HP drum T_{sat} rate of increase observed during the startup in Figure 11 is near the upper limit of what is generally considered a permissible rate for drums of this thickness during a warm start. After several hundred such warm starts from relatively low pressure, corrosion fatigue cracks around the downcomer, and possibly other nozzles in the drum, can be expected.

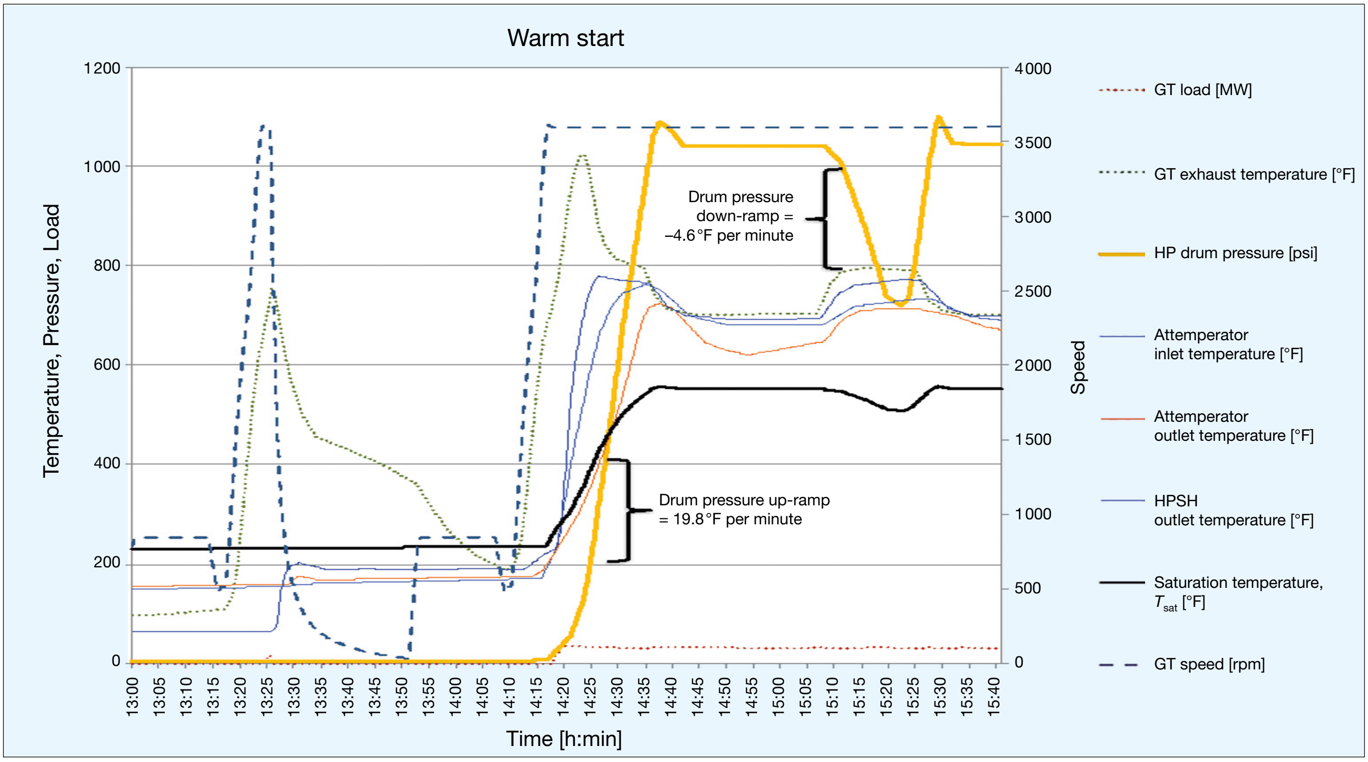
Forced Cooling

Many owners force cool the GT and HRSG following shutdown in order to expedite commencing maintenance work on the GT and/or HRSG. Forced cooling often employs depressurization of the HRSG by venting steam through the HP and HRH bypass systems or HP sky vent following shutdown and spin cooling of the GT. If not carefully managed, forced cooling can impose extreme thermal transients on the HP drum, HPSH/RH headers and piping, and main steam/HRH piping. Figure 12 presents plots of DCS data showing evidence of overly aggressive HP drum ramp rate and quenching of the HPSH and main steam piping during forced cooling.

HP Bypass Pressure Control Valve (PCV) Erosion

Abnormal erosion of the seat plug and cage in HP bypass PCV has become relatively common in valves manufactured by various valve OEMs. This erosion is caused by passing wet steam and/or water through the PCV. All PCV OEMs require that some superheat be available before opening the PCV. However, many units are equipped with control logic that opens the PCV immediately upon GT light off during startup, or operating procedures permit opening of the PCV sometime after GT light off, but before the main steam pipe upstream of the PCV is sufficiently heated. PCV OEMs' attempts to eliminate this erosion via changes to internal component arrangements and the use of harder materials have not been effective. Seat/plug seating surfaces often remain tight in cycling service for about 5 years before service is required. Figure 13 shows a photo of a PCV seat with normal wear after 5 years of cycling service.

Figures 14 and 15 show photos of PCV plugs with severe erosion after only a few start/stop cycles and about 1 year of service, respectively.



Drum pressure down-ramp = –4.6 °F per minute

Drum pressure up-ramp = 19.8 °F per minute

Figure 11:
Aggressive startup ramp rate of a relatively thick-walled 121 mm (4.75 in) HP drum.

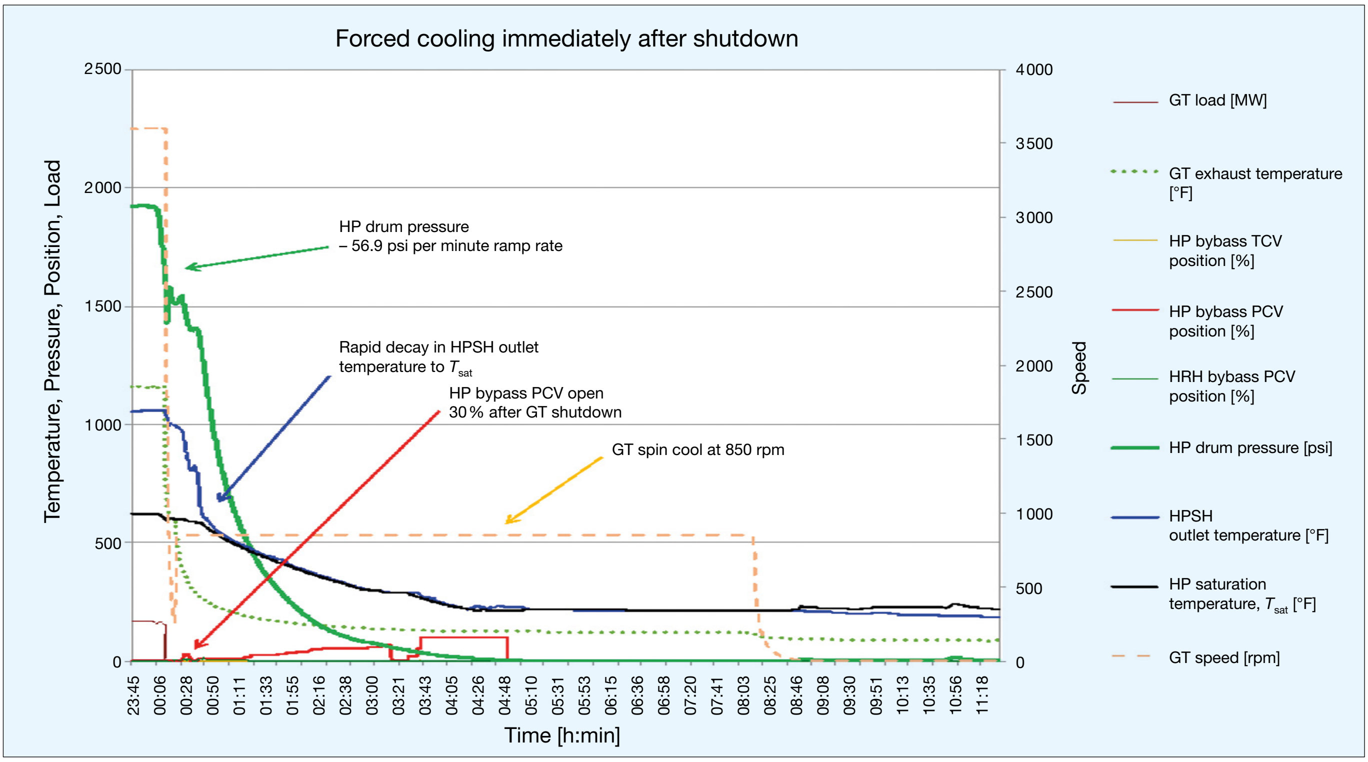
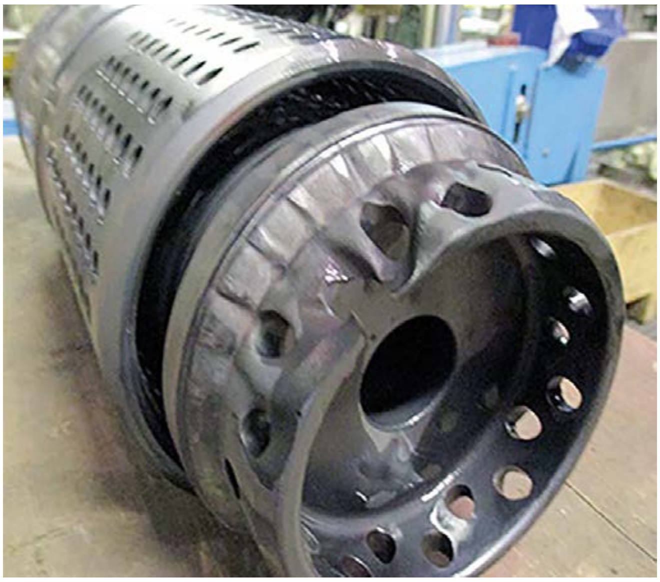


Figure 12:
Aggressive depressurization ramp rate of HP drum and rapid cooling of HPSH outlet and main steam pipe.

Figure 13:
Normal PCV seat wear after 5 years of cycling service.

Figure 14:
Abnormal PCV plug and cage wear after only a few start/stops.



As erosion damage to the seating surfaces progresses an increasing amount of superheated steam leaks through the PCV during normal operation. Eventually this leaking results in overheating of the downstream carbon steel pipe. To prevent overheating damage to the downstream pipe some operators manually open the HP bypass desuperheater spray valve to cool the downstream pipe. This practice is inappropriate and certain to cause thermal fatigue failures in welds and piping at and downstream of the desuperheater.

In spite of PCV OEMs' requirement that the PCV remain closed until superheated steam is available, few if any plants are equipped with permanent instrumentation to measure steam temperature at the PCV inlet. Therefore, steam temperature measurements upstream and downstream of the PCV branch tee must be used to infer when

Figure 15:
Abnormal PCV plug and cage wear after about one year of service.

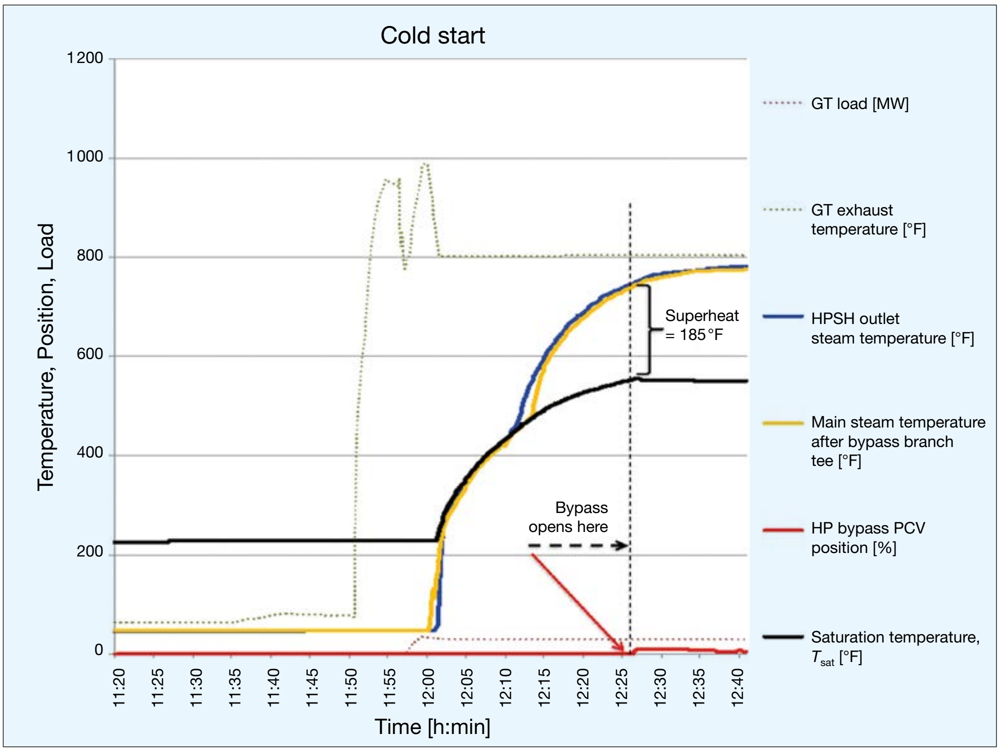


Figure 16:
PCV opened after the main steam temperatures measured upstream and downstream of the PCV branch tee indicate superheat.

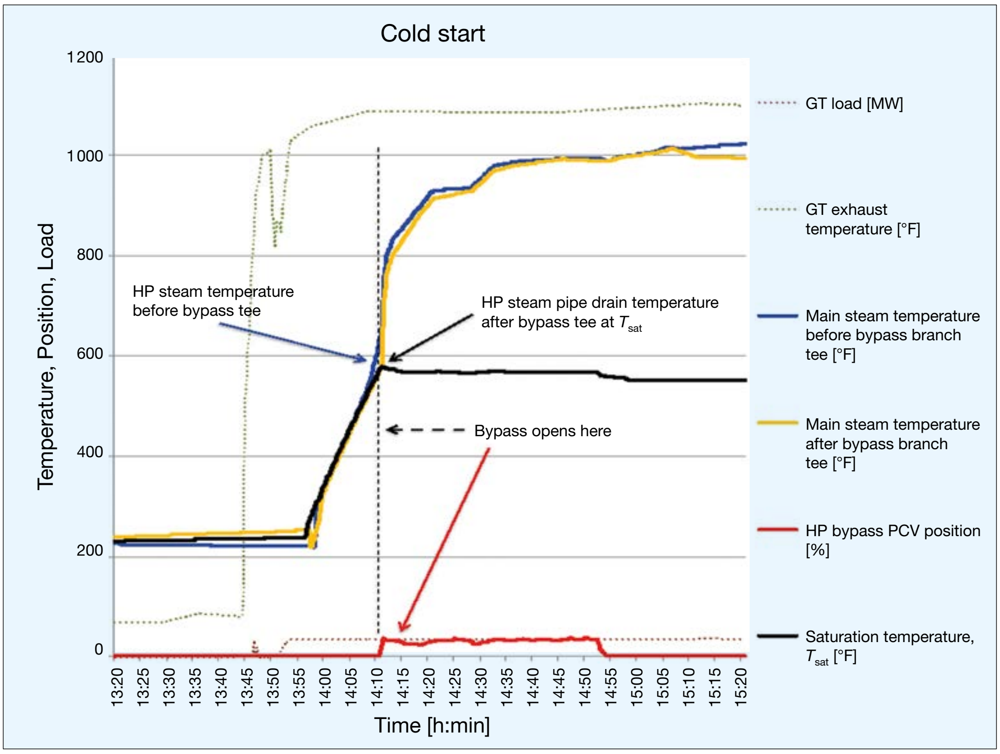


Figure 17:
PCV opened before the main steam temperature measured downstream of the PCV branch tee indicates superheat.

it is safe to open the PCV. Figures 16 and 17 present DCS data plots of main steam pipe temperature showing a PCV opened during startup after superheated steam is available to the PCV and one opened prior to dry superheated steam becoming available, respectively.

Thermal surveys and root cause analyses conducted during the last few years have identified the disturbing trend of automated controls opening the HP bypass PCV on GT ignition. Opening the PCV on light off during warm and hot starts may or may not expose the PCV to wet steam and/or water depending upon a number of variables such as the duration of the layup, ambient temperatures, etc. Opening the PCV at light off during cold startups ensures that the PCV will ingest water. Condensate generation in the main steam pipe upstream of the bypass branch tee is unavoidable while warming the piping. Some of this condensate will be pulled past main steam piping drains and pass through the PCV.

5.2 RANKING OF KEY CAUSES OF DAMAGING THERMAL TRANSIENTS IN COMBINED CYCLE/ HRSG PLANTS ASSESSED

The original paper [1] evaluated and ranked 55 potential causes of damaging thermal transients in the 11 units assessed. Analysis of thermal transients in an additional 43 units reveals that during the 10 years since the initial results were published many of the 55 potential causes are rarely observed due to improvements in equipment design and operating procedures. Table 3 shows the most recent ranking of potential causes that continue to cause avoidable damage to equipment and/or HTF.

For the reader this table provides the most important thermal transient aspects which need to be addressed by plants to ensure they are on the path to reliability. The table shows that the most common deficiencies are related to attemperator protective logic and operating policies that permit manual manipulation of the attemperator controls and ineffective superheater drain equipment and/or operation. As with the cycle chemistry findings in Section 3, the organizations' failure to challenge the status quo is a factor in not identifying and addressing these deficiencies.

6 ALLEVIATION OF PROBLEMS

6.1 HOW TO ADDRESS CYCLE CHEMISTRY IN NEW AND CURRENTLY OPERATING PLANTS

The optimum cycle chemistry control of combined cycle/ HRSG plants is of paramount importance in achieving and maintaining the desired availability, reliability, and performance. There are a number of key basic features which need to be adopted and addressed to achieve this highest level of operational performance. These involve primarily ensuring that the cycle chemistry drivers for the main cycle chemistry influenced damage mechanisms are comprehensively understood and addressed in developing and monitoring the cycle chemistry for combined cycle/ HRSG plants. The major damage/failure mechanisms of concern and which are still occurring at high frequency worldwide include: a) HRSG Tube Failures due to FAC and UDC, b) deposition in the HP evaporators, c) transported corrosion products from the lower pressure circuits, d) pitting due to inadequate shutdown protection, and e) steam turbine phase transition zone failure initiated at pits. The first step is to ensure that optimum chemistry treatments and controls will be used on the plant by reference to the suite of IAPWS TGD during the initial specification phase of a plant. These TGD need to be customized to the plant once operational as many of the problems reported relate to plants not challenging the status quo and keeping the chemistry treatments and controls up to the latest inter-

Thermal Transient Category	Combined Cycle/HRSG Plants [%]
Routine attemperator hardware inspections conducted	18 ↑
Leaking attemperator spray evident in DCS data	82 ↑
Attemperator spray Master Control/Martyr Block valve logic used	95 ↑
HPSH attemperator overspray evident in DCS data	31 ↑
RH attemperator overspray evident in DCS data	12 ↑
Inappropriate attemperator operation permitted	39 ↑
HPSH or RH drain pipes too small	65 ↓
HPSH/RH drain pipes sloped downward	29 ↑
Blowdown tank elevation higher than lower HPSH/RH headers	47 ↓
Poor HPSH draining evident in DCS data	63 ↓
Poor RH draining evident in DCS data	68 ↑
HPSH/RH drains open during purge	58 ↑
Prudent HP drum ramp rate exceeded during startup	25 ↑
Exhaust temperature matching used during cold lag, warm or hot starts	16 ↓

Table 3:
Analysis of avoidable causes of thermal transient induced damage/ failure in 54 combined cycle/HRSG plants. The numbers in the table represent the percentage of plants where the particular cause was identified and the arrow indicates the trend.

national standards. Also, a plant needs to ensure that the general guidance is translated into the three guiding principles provided in Section 4.2 for chemistry control of a combined cycle/HRSG plant.

Once a plant is operational the plant operations/chemical staff should introduce and conduct the very powerful assessment methodology of RCCS discussed in Section 3. These identify the basics of cycle chemistry control that are not being used or adhered to by the plant. It is very clear from the large data base reported in this paper that operating outside of optimum approaches and without adequate cycle chemistry control systems (monitoring, instrumentation, analysis, measurement of HP evaporator deposits, etc.) will lead to failure of or damage to the plant. When the analysis is conducted by the authors at plants, they always provide an outline of the steps (action plans) required to eliminate the RCCS and usually suggest a time frame to do so. Addressing each RCCS with an action plan to eliminate the situation has been shown to address future failure and damage. This assessment methodology is also used in root cause analysis studies of cycle chemistry influenced damage/failure.

Section	Subject
1.0	Introduction
2.0	Purpose
3.0	Objectives/Goals of Chemistry Program
4.0	Program Benchmarking
5.0	Repeat Cycle Chemistry Situations (RCCS)
6.0	Program Roles and Responsibilities
7.0	Cycle Chemistry Treatment Chemicals (IAPWS Guidance)
8.0	Feedwater Treatment (IAPWS Guidance for AVT)
9.0	Drum/Evaporator Water Treatment (IAPWS Guidance for Volatile or Alkali Treatment)
10.0	Cycle Chemistry Targets and Action Levels
11.0	Shutdown Protection of Steam-Water Cycle Components
12.0	Drum Carryover Testing (Extracted from IAPWS TGD)
13.0	Air In-Leakage (Development of AIL Team from IAPWS TGD)
14.0	Makeup System
15.0	Grab Sample and Total Iron Analysis Procedures (Extracted from IAPWS TGD)
16.0	Equipment Inspections (Especially Internal of Pressure Vessels: Drums and DA)
17.0	References and Source Documents
18.0	Signature/Approval of VP Operations/Plant Manager

Table 4: Typical content of plant cycle chemistry manual.

As discussed in Section 3.1 most of the plants assessed do not have a comprehensive Plant Chemistry Manual which includes the latest international cycle chemistry targets and action levels (IAPWS) for the operators, and all the other cycle chemistry procedures so that staff in the plant are aware of the importance of the cycle chemistry control. A typical outline of a comprehensive document is included as Table 4. It is important to note that development of Section 10 should take a minimum of two steps: a) initially the guidance can be customized from the IAPWS Guidance, and b) the final guidance can only be developed from a monitoring program which includes corrosion product monitoring (Section 15).

6.2 HOW TO ADDRESS FAC IN NEW AND CURRENTLY OPERATING PLANTS

Section 4.2 has delineated the approaches for single- and two-phase FAC, the optimum chemistries to avoid FAC, the monitoring of total iron, and the levels indicating that minimum FAC is occurring. These features are basically the same for new and operating plants.

6.3 HOW TO ADDRESS THERMAL TRANSIENTS IN NEW AND CURRENTLY OPERATING PLANTS

Leaking Attemperator Spray Water

The use of Master Control/Martyr Block valve logic is identified in Section 5.1 as a major cause of attemperator spray water leaking. Elimination of spray water leaking can be achieved by inspecting and repairing the block and control valves if currently leaking and reversing the attemperator valve protection logic to a Master Block/Martyr Control valve logic and an attemperator System Release permissive. Instead of a futile attempt to protect the control valve seat/plug from damage, this revised logic will protect the much more expensive to repair steam piping and HPSH/RH from damage.

Master Block Valve/Martyr Control valve logic will open the block valve before opening the control valve and close the control valve before closing the block valve. The block valve should close as soon as the control valve is proven closed after a short time delay. To avoid excessive block valve opening and closing during unit operation, open the block valve during startup only after the attemperator System Release permissive is active. System Release permissive criteria should include the following and require that all be satisfied prior to activation:

- GT is firing;
- GT exhaust temperature (or HPSH/RH outlet steam temperature) exceeds a value in the range of 510 °C (950 °F);
- Minimum HP/RH steam flow is achieved.

The block valve should remain open until the System Release permissive becomes inactive during shutdown when any one or more of the permissive criteria are not met. Both the block and control valves should be closed (using Master Block Valve/Martyr Control Valve logic) any time the System Release permissive is inactive.

Attemperator Overspray

Overspray is identified in Section 5.1 as a frequent cause of damage to steam pipes and tubes. Elimination of overspray can be achieved taking the following actions:

- Repair and/or upgrade attemperator equipment if poorly maintained or substandard hardware is in use;
- Ensure the attemperator's control system is capable of automatically maintaining outlet steam temperatures within limits, or nearly so*, with no requirement for operator intervention. This requires the use of a properly designed and tuned cascade control system. In cases where steam pipe length downstream of the attemperator and/or HPSH/RH heating surface distribution are marginal, model-based controls may provide improved performance. (*Permitting a slight increase in outlet steam temperature for limited periods of time during startup is far less damaging than permitting overspray to occur.);
- Prohibit operators from manually manipulating the attemperator's setpoint or manually operating the attemperator spray valve;
- Ensure the attemperator's control system includes an Overspray Protection feature. This feature should prevent further opening of the spray control valve when attemperator outlet steam temperatures decrease to 28 °C (50 °F) above saturation temperature.

Attemperator Operation When Inappropriate

Operation of the attemperator when steam flow is low or zero is identified in Section 5.1 as a frequent cause of severe damage to steam pipes and tubes. Prevention of such damage can be avoided by ensuring that an attemperator System Release permissive as described above (in the discussion on avoiding attemperator spray leaking) is installed and maintained. In addition, because the interstage attemperator cannot be designed to provide HPSH/RH temperatures suitable for rolling and warming a cold steam turbine, attempts to use it during startup for this purpose should be prohibited. GT load limits, GT exhaust temperature control features, and/or terminal attemperators should be used to satisfy steam turbine startup temperature requirements.

Failure to Adequately Drain the HPSH/RH during Startup

Migration of undrained water was identified in Section 5.1 as a common cause of damage to steam pipes, headers, and tubes. Ensuring complete draining of the HPSH and RH during startups initiated from all system pressures can be a complex exercise due to the variation in HPSH/RH arrangement, external steam and drain pipe arrangement, drain valve type and size, blowdown tank location, and the method by which drain valves are controlled. If review of HPSH/RH drain performance reveals that all water is not removed before the initiation of forward steam flow during all startups, modifications to drain equipment, operating procedures, and controls should be developed and implemented. Key steps in developing effective modifications include:

- Calculating the rate of condensate formation during the prestart purge in each HPSH and RH harp during startup from various initial pressure conditions;
- Using the foregoing peak condensation rates to determine the minimum drain pipe sizes and the arrangement necessary to drain the HPSH and RH at the rate of condensate formation during startup from any initial HP drum and RH pressure.

Features that should be included in drain system modification include:

- Route drains with continuous downward slope to the blowdown tank entry point. This will require a horizontal tank at grade, a vertical tank in a pit, or a blowdown tank bypass to atmosphere when HPSH/RH pressure is below that required to move water up into an elevated blowdown tank. Atmospheric blowdown tank bypass has been safely used by some owners during early startup when system pressure is below 2 bar (29 psig);
- No interconnection of HPSH and RH drains prior to entering the blowdown tank;
- Consider a separate RH blowdown tank if back pressure is developed in the blowdown tank when HPSH drains are open, or use a blowdown tank bypass as described above;
- Drain pipe thermocouples to close drain valves during startups initiated from low pressures after consistent superheat is detected in the drain pipe;
- Determination of optimum drain valve opening/closing positions and timing for startups initiated from moderate and high pressures. This may require considerable field testing to achieve adequate draining without excessive release of steam during startups from varying initial pressures;

- Installation of an effective automatic drain valve system;
- Compliance with personnel safety and/or environmental protection practices.

HPSH/RH drain operating procedures should strive to accomplish the following:

- Drain accumulated water prior to initiating the prestart purge;
- Drain condensate formed during the prestart purge at the rate it forms so as to not permit condensate to accumulate in the HPSH/RH (this avoids delay in initiating cooling steam flow to the HPSH/RH while waiting to drain accumulated condensate);
- Avoid excessive release of steam that may result in overly aggressive HP drum pressure decay and/or over heating of blowdown system components;
- Prior to and during pressurized startups operate HPSH drain valves simultaneously rather than in sequence (this prevents the drop in pressure that occurs in the section of HPSH with the open valve from drawing water "over the top" from HPSH sections with closed drain valves). RH drain valves should also be operated simultaneously.

Automatic Drain Control

Given the rapidity of events during startup, and the need for precision sequencing and timing of HPSH/RH drain valve operation, automation of HPSH and RH drain valves is much preferred. Assuming that drain pipes are sufficiently large and routed using the guidance above, automatic operation of HPSH drain valves prior to and during startups from zero and low initial pressures is relatively simple to accomplish via the following procedure:

- Open all drain valves prior to initiation of the prestart purge to remove any water accumulated during layup;
- Leave all drain valves fully open during the prestart purge and let them remain open after GT light off;
- Automatically close each drain valve when its drain pipe temperature consistently indicates a moderate amount of superheat;
- Since there is little to no HP drum pressure when using this simple procedure, there is no risk of overly aggressive drum pressure down ramp rate, nor any risk of taxing the blowdown system's design limits.

Automation of HPSH drain control during startups initiated at high pressures is considerably more complex and difficult. Since it is important to delay initiating steam flow until the HPSH/RH are completely drained and permitting condensate to accumulate in HPSH/RH coils slows the draining process, it is useful to drain condensate from the HPSH/RH as it forms during the purge. In this way cooling steam flow can be provided to the HPSH/RH tubes very shortly after GT ignition. The guidance provided above to determine the optimum opening/closing positions and timing of drain valves via field tests is possible, but not very practical for a unit that starts frequently and/or from various initial pressures. The opening/closing positions and timing of drain valves required to adequately drain the HPSH/RH without excessive release of steam vary significantly depending upon system pressures. Unfortunately, drain pipe temperature is of little value in controlling drain valves prior to GT ignition since no heat input is available to create superheated steam. Therefore, both water and steam in the drain pipe are at or near saturation temperature and some other method of determining when to open the drain valve to remove water and when to close it to avoid releasing steam is needed.

Some of the HRSGs in the 54 CCGT plants evaluated are equipped with drain pots utilizing thermocouples, conductivity probes, or float switches on HPSH/RH drains in an attempt to automate drain control. Some others use system pressure values in an attempt to do so. In some cases, the owner had ceased to use and maintain these systems due to their ineffectiveness and/or unreliability. In other cases, the operating data plots, such as those in Figure 10, demonstrate that the automation system did not work effectively. It should be noted that while operating data obtained from permanent steam temperature instrumentation like that in Figure 10 can indicate gross amounts of undrained water passing from sections of the HPSH/RH, this relatively slow to respond instrumentation may fail to indicate smaller, but still damaging, amounts of migrating water. Rapid response thermocouples installed on HPSH/RH tubes and internal piping like those described in Section 5 may be required to ensure adequate draining during all startup conditions.

Calculation of condensation rates in the hottest HPSH coil of a typical F-class HRSG during the prestart purge with HP pressure around 69 bar (1 000 psi) will yield a peak value in the range of 9070–13 610 kg per hour (20 000 to 30 000 lb per hour). A very large drain pot is required to control such a large flowrate while avoiding flooding of the pot and/or permitting steam to escape. Some years ago one of the authors participated in an Electric Power Research Institute (EPRI) project to design a drain pot that could reliably accomplish this task. The resulting drain pot consisted of multiple interconnected 15.24 cm (6 in) diameter columns each about 1.524 m (5 ft) tall. While this device would likely have worked, its size, cost, and complexity made it impractical. Bob Anderson then worked with EPRI to determine if a means of automatically controlling HPSH/RH drain valves using ultrasonic sensors could be developed. This work resulted in the development of such a system, which is commercially available from FLEXIM GmbH, Germany, a supplier of ultrasonic flow meters. The EPRI/FLEXIM liquid detection sensors are attached to the exterior of the drain pipe, require no penetration of the pipe, require very little space, can be used in new construction, and can be retrofitted to existing drain systems. Retrofit requires informed evaluation of the existing drain pipe/valve/blowdown tank details and arrangement to determine if modifications are required. EPRI has developed control logic for use with the FLEXIM system and made both installation requirements and the control logic available in the public domain. At the time of writing retrofit systems are installed on 4 HRSGs, and 2 new construction HRSGs are awaiting installation of the system.

Aggressive HP Drum Pressure Ramp Rates

Aggressive increasing and decreasing HP drum pressure ramp rates were identified in Section 5.1 to be a common cause of cracking in downcomer and sometimes steam nozzle connections. Avoiding these cracks requires operating the unit in a manner that limits up and down HP drum pressure ramp rates to those specified as the maximum permitted by the HRSG OEM (or other competent person). Owners of older HRSGs may not have been provided with suitable drum ramp rate limits since ASME Code does not require the OEM to perform the fatigue life assessment required to determine these ramp rate limits. If ramp rate limits are not available, or the suitability of original ramp rate limits is questioned, new ramp rate limits should be procured from the HRSG OEM or other competent persons. The ramp rate limits should be incorporated into the plant's startup and shutdown procedures, preferably in an automated fashion. In some units it may be necessary to hold GT load at a low value for some period during cold/warm startup to avoid exceeding safe HP drum ramp rate limits. HP bypass and HP sky vent availability and capacity are key factors in complying with drum ramp rate limits later in the startup.

Forced Cooling

Section 5.1 identified forced cooling as a potential cause of damaging thermal transients in the HPSH, RH, main steam pipe, and HRH pipe. Review of operating data from several HRSGs while using the HP and HRH bypass systems after the GT is shut down to expedite depressurization of the HP system revealed that damaging thermal transients do not occur in all cases. While sufficient data has not yet been reviewed to reliably predict under which conditions damaging transients will or will not occur, it appears that depressurizing in this manner immediately after GT shutdown may be less harmful than doing so after the GT/HRSG gas path has cooled. Having said this, unit specific characteristics related to GT heat retention and coast down may render this preliminary observation untrue for some units. Owners are advised to use caution and closely monitor HPSH/RH outlet temperatures and main steam/HRH pipe temperatures any time the HP and HRH bypass systems are in use with the GT not firing.

HP Bypass Pressure Control Valve (PCV) Erosion

While not a thermal transient, abnormal erosion of the seat, plug, and cage in HP bypass PCV by ingestion of wet steam was identified in Section 5.1 as an increasingly common damage mechanism. This can be avoided by delaying opening of the HP bypass PCV until steam temperatures upstream and downstream of the HP bypass branch tee have increased above saturation temperature during startup. The practice of opening the HP bypass PCV at GT ignition should be avoided since no steam pipe warming has yet occurred and much of the condensate formed in warming these pipes will be ingested by the PCV. In 2x1, 3x1, etc. units the HP bypass PCV branch tee is often located just upstream of the common steam header isolation valve. Typically, a drain pot with an automatic drain control is located between the branch tee and isolation valve. Since this steam pipe drain arrangement primarily disposes of only water accumulating in the drain pot and does not provide a substantial steam flow to rapidly warm the pipe, there may be an excessively long delay before superheated steam is available at the PCV inlet. This is the case for the plots provided in Figure 17. In such cases the installation of a sufficiently sized steam pipe warming drain between the isolation valve and bypass branch tee may be necessary to both open the PCV soon after GT ignition and protect the PCV from excessive erosion damage.

6.4 CONDUCTING AN ASSESSMENT/SURVEY: PLANTS COULD/SHOULD FOLLOW SAME APPROACH AS DESCRIBED IN SECTION 1 BACKGROUND

All of the assessments and surveys reported in this paper have been conducted by the authors during a two-day visit to the plant. The processes used have been described and the format of the results presented. The authors suggest that plant staff could perform similar assessments themselves as they are not beyond the capabilities of competent plant/corporate staff. It would require becoming knowledgeable about the details and methods described in this paper as well as obtaining pertinent and accurate plant information. However, over the years few organizations have developed the ability (or desire) to self-perform these types of assessment, maybe because of the continuing trend towards fewer and fewer plant/corporate people having the time to do so.

7 SUMMARY, CONCLUSIONS & TOWARDS THE FUTURE

Ninety combined cycle/HSRG plants around the world have been assessed/surveyed to provide an indication of the current status of the proactiveness of operators in addressing the known failure/damage HRSG Tube Failure (HTF) mechanisms, and the potential for damage in thick section pressure vessels. As in the first publication of similar results for only 11 plants [1], the three most important aspects have been assessed: cycle chemistry, FAC, and thermal transients. In the first, the assessments have addressed the key factors for FAC, UDC, deposits, pitting, and failures in the phase transition zone of the steam turbine. In the last, the assessments have addressed thermal fatigue and creep fatigue due to inadequate operation of attemperators, drain control of superheaters and reheaters, HP drum ramp rates, and forced cooling. The emerging issue of severe erosion of HP bypass pressure control valves has been introduced. The paper includes numerous examples in each category of the important operating, equipment, and control features so plant personnel can identify them in their plants. Overall the assessments/surveys have provided a clear picture in each area of exactly where the weaknesses in the current approaches are occurring. It is hoped that the key messages within this paper can easily be applied by operators to change around the current situation.

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