Assessments of HRSGs – Trends in Cycle Chemistry and Thermal Transient Performance

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ABSTRACT

The paper provides information from one-day assessments of HSRGs with concentrations on the cycle chemistry and thermal transients. The primary goal of the work was to assist operators in being proactive in identifying the key drivers for cycle chemistry and thermal transient induced failure and damage mechanisms. In the former, the assessments have addressed the key factors for flow-accelerated corrosion (FAC), under-deposit corrosion (UDC) and pitting. In the latter, the assessments have addressed thermal fatigue and creep fatigue. In each area, the assessments have provided a clear picture of exactly where the weaknesses in the approaches are occurring, and it is not surprising that the current ranking order for HRSG Tube Failure has remained rather static for the last 10 years. The paper outlines the approaches to optimize the cycle chemistry to avoid FAC and UDC, the operation of attemperating systems and the configuration of drain systems to avoid the thermal transient driven damage mechanisms. These key messages can easily be applied by operators to change the current situation of waiting for failure to occur.

INTRODUCTION

The mechanisms which cause unreliability of HRSGs worldwide are becoming established and stable. The leading HRSG tube failure (HTF) mechanism is flow-accelerated corrosion (FAC) followed by thermal fatigue problems. FAC involves the single- and two-phase variants [1], predominantly in low pressure (LP) economizers/preheaters and LP evaporators (tubes, headers and risers) with an increasing number of incidents in intermediate pressure (IP) circuits (tubes and risers) [1]. All the HRSG components within the temperature range 100–250 °C (212–482 °F) are susceptible.

Thermal fatigue occurs in superheaters and reheaters primarily at header/tube connections due to undrained condensate and attemperator overspray during startup [2]. Creep-fatigue examples are increasing at the same locations in HRSGs operating at higher temperatures (565 °C (1 050 °F)) and particularly in circuits containing dissimilar metals at the header/tube connections (T/P 91 and T/P 22) [3]. Thermal fatigue is also observed in low temperature economizer circuits due to steaming and quenching of the condensate inlet section during startup [4].

The third most important areas of failure/damage are the under-deposit corrosion (UDC) mechanisms in high pressure (HP) evaporator tubing, which as the name implies first requires a deposit on the inner surface of the HP evaporator tube and then some contaminant or the use of in correct cycle chemistry treatments that are allowed to concentrate within the deposit and result in increased corrosion, loss of tube wall and eventually failure. By far the most important of these mechanisms is hydrogen damage, which relates to the concentration of chloride (from contaminant ingress such as condenser leakage) within and beneath the deposit. However, evaporator chemical treatments using acidic phosphates, blends of phosphate or excessive levels of sodium hydroxide can also concentrate and cause damage. Pitting tube failures can occur in any HRSG circuit as a result of repetitive inadequate, and in nearly all cases, non-existent shutdown procedures [5].

Over the last year the authors have visited eleven combined cycle plants worldwide to conduct assessments of the cycle chemistry and thermal transient aspects of the HRSGs. The essence of these assessments has been to help the operators identify and address previously undetected problems proactively. This is 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.

These assessments have 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. These are rarely identified, and if allowed to continue without remediation, these repeating or continuing features will eventually lead to failure or damage [5]. There is very little variation across the fleet worldwide as this paper clearly illustrates. In some ways this is fortunate because it should allow the operator to review the data in this paper, and resolve to make the necessary changes knowing that there is a track record in alleviating and correcting the drivers which are commonly present and active. Solutions to the cycle chemistry influenced areas are much more mature than those for the thermal transient issues. But both 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 plant. The authors are already making these applications for operators around the world. But the most important aspect is that organizations can be proactive with plants which haven't already experienced failure. On HRSGs, it is never satisfactory to sit back complacently because incipient damage hasn't yet manifested itself as failure.

ASSESSMENT PROCESS

Table 1 shows the wide extent of the plants which have been assessed around the world. They include seven HRSG manufacturers, four gas turbine (GT) manufacturers, and six steam turbine manufacturers, and have a wide range of operating experience (hours and starts). The cooling varies from river to seawater to air-cooled condensers and some have cooling towers. The last column of the table provides an HRSG Benchmarking score and category to provide a ranking on a worldwide basis. The Benchmarking process was introduced in 2004 [6] and involves the following non-subjective questions (factors) and possible answers:

1. How many HRSG tube failures (HTF) have there been over the last three years (0, 1–2, 3–5, 6–10, > 10)? Weight of factor is 3.

Plant	Size/configuration	Gas turbine	Steam turbine	HRSG
A	535 MW 2 x 1	GE 7FA Steam augmentation	GE D11	Vogt triple-pressure duct burners SCR + CO catalyst
B	170 MW 2 x 1	GE LM6000 Steam augmentation DENOX	Nuovo Pignone	Nooter/Eriksen double-pressure duct burners SCR + CO catalyst
C	85 MW 3 x 1	GE LM2500 Steam NOX control	GE DEX11	Zurn triple-pressure duct burners SCR + CO catalyst
D	525 MW 2 x 1	GE 7FA	Toshiba	Vogt triple-pressure duct burners + SCR
E	540 MW 2 x 1	Siemens W501FD2	Siemens HE	NEM triple-pressure
F	380 MW 1 x 1 (single shaft)	Siemens V94.3A	Siemens	Nooter/Eriksen triple-pressure
G	380 MW 1 x 1 (single shaft)	Alstom GT26	Alstom	Alstom triple-pressure
H	400 MW 1 x 1 (single shaft)	MHI M701F	MHI TC2F-30	NEM triple-pressure
I	760 MW 2 x 1	GE 9FA	GE	Nooter/Eriksen triple-pressure
J	286 MW 1 x 1	Siemens V84.2	Siemens	ABB triple-pressure SCR + CO catalyst
K	90 MW 2 x 1	GE MS 6000	GE	Deltak triple-pressure

Table 1: Demographics of the combined cycle units assessed.
(Table to be continued on page 134.)

(Table 1 continued)

Plant	Steam conditions			Approximate operation time/ starts @ assessment	Cooling water/ condenser tubing	HRSG benchmark score and category [1]
	HP	IP	LP			
A	565 °C (1 050 °F) 14.5 MPa (2 100 psi)	565 °C (1 050 °F) 3.1 MPa (450 psi)	0.48 MPa (70 psi)	14 000 h 570 starts	ACC [2]	25 Above Average
B	432 °C (810 °F) 5.9 MPa (865 psi)		227 °C (440 °F) 0.37 MPa (55 psi)	4 000 h 300 starts		17 Above Average
C	488 °C (910 °F) 6.1 MPa (885 psi)	288 °C (550 °F) 2.7 MPa (400 psi)	110 °C (229 °F)	130 000 h 530–630 starts	Cooling tower	40 Average
D	568 °C (1 055 °F) 13.5 MPa (1 968 psi)	568 °C (1 055 °F) 3.3 MPa (477 psi)	299 °C (570 °F) 0.49 MPa (72 psi)	10 000 h 130 starts	ACC	22 Above Average
E	568 °C (1 055 °F) 11.9 MPa (1 726 psi)	568 °C (1 055 °F) 2.42 MPa (351 psi)	0.37 MPa (55 psi)	4 000 h 190 starts	River (10–20 $mg \cdot kg^{-1}$ Cl) Stainless tubing	26 Average
F	565 °C (1 050 °F) 12 MPa (1 740 psi)	565 °C (1 050 °F) 2.3 MPa (333 psi)	0.4 MPa (58 psi)	75 000 h 340 starts	Sea water Cooling tower Titanium tubing	28 Average
G	565 °C (1 050 °F) 12 MPa (1 740 psi)	565 °C (1 050 °F) 2.75 MPa (398 psi)	0.45 MPa (65 psi)	80 000 h 350 starts	River (200 $mg \cdot kg^{-1}$ Cl) Stainless tubing	26 Average
H	538 °C (1 000 °F) 10.4 MPa (1 500 psi)	566 °C (1 050 °F) 3.4 MPa (493 psi)	0.59 MPa (85 psi)	13 000 h 90 starts	River (15 $mg \cdot kg^{-1}$ Cl) Cooling tower Stainless tubing	22 Above Average
I	565 °C (1 050 °F) 12 MPa (1 740 psi)	565 °C (1 050 °F) 2.3 MPa (334 psi)	0.4 MPa (60 psi)	36 000 h 120 starts	Sea water Titanium tubing	31 Average
J	500 °C (932 °F) 6.6 MPa (962 psi)	249 °C (479 °F) 0.88 MPa (128 psi)	0.41 MPa (60 psi)	72 000 h 300 starts	Cooling towers	Not conducted
K	443 °C (830 °F) 6.06 MPa (880 psi)	268 °C (514 °F) 2.27 MPa (330 psi)	0.06 MPa (10 psi)	126 300 h 336 starts	Cooling tower	Not conducted

Table 1: Demographics of the combined cycle units assessed.
[1] HRSG benchmark factors, score and category are discussed in the text.
[2] ACC is air-cooled condenser.

2. How many chemistry influenced failures have there been over the last three years (FAC, UDC, corrosion fatigue, pitting) (0, 1–2, 3–5, 6–10, > 10)? Weight of factor is 3.
3. What percentage of the fundamental level of cycle chemistry instrumentation does the plant have (100, 90–99, 70–89, < 70 %)? Weight of factor is 3.
4. Is a reducing agent (oxygen scavenger) used in the condensate and feedwater during operation or shutdown (Yes, No)? Weight of factor is 2.
5. What is the level of total iron in the feedwater (< 5, 5–10, 11–20, > 20 $\mu g \cdot kg^{-1}$ or "don't know")? Weight of factor is 2.
6. What is the level of total iron in each drum (< 5, 5–10, 11–20, > 20 $\mu g \cdot kg^{-1}$ or "don't know")? Weight of factor is 2.
7. Has tube temperature monitoring been conducted in the LP economizer, superheater and reheater during startup, shutdown and operation to identify damaging thermal transients (Yes, all three; Yes, on two; Yes, on one; No)? Weight of factor is 2.
8. Does the plant have written action plans to address the root causes of HTF or potential HTF (Yes, No)? Weight of factor is 1.
9. Does the plant have written action plans to address damaged tubing or potential damaged tubing (Yes, No)? Weight of factor is 1.

Each answer has an associated score which is multiplied by the weight of importance of the factor. The total provides the ranking or category with < 5 being a Worldclass HRSG, 6–10 being Very Good, 11–25 being Above Average, 26–40 being Average, 41–45 being Below Average, and 46–55 being Poor.

The assessment process is conducted during a one day visit by the authors to review the design, construction, operation and cycle chemistry of the combined cycle and HRSG.

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

a) The heat balance diagrams for the plant.
b) The arrangements of the tubing circuits.
c) The cycle chemistry treatments in the condensate and feedwater and in each drum, including the actual chemicals added to the plant. The operating and shutdown conditions are included.
d) The installed on-line instrumentation and how close it comes to the Structural Integrity Fundamental Level of Instruments, and whether they are alarmed in the control room.
e) Review of any cycle chemistry influenced HTF.
f) Particular review of the FAC potential for the unit, which includes the materials identification and operating temperatures of the LP and IP circuits which are known to be susceptible to FAC [1].
g) The monitored total iron levels in the feedwater and drums.

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

a) For superheater and reheater – dimensions, materials and arrangement of tubes, headers, interconnecting pipes, attemperators, HP steam pipe, cold reheat pipe, drains, and flash tank.
b) For low pressure economizer – dimensions, materials and arrangement of tubes, headers, interconnecting pipes, drains and condensate pipe.
c) For both lead and lag units in 2 x 1 plants: Historical distributed control system (DCS) plots of GT load, GT speed, GT exhaust temperature, HP steam flow, HP drum pressure, HP superheater outlet temperature, attemperator inlet and outlet temperatures, HP spray water valve position, and superheater drain valve positions for a typical cold start, hot start and normal shutdown. Equivalent DCS points for the reheater system are also required for units with reheaters.
d) For both lead and lag units in 2 x 1 plants: Operating procedures used for cold starts, hot starts and normal shutdowns.

TUBE FAILURE PREVENTION PROGRAM

It is very common for organizations to assume the cause of a unit's first tube failure is "a bad weld". Sometimes this may be true, but in many cases the actual root cause is an undetected cycle chemistry shortfall, design feature, or operating practice that has repeatedly inflicted corrosion, corrosion fatigue, or thermal-mechanical fatigue damage in the failed tube and its neighbors. None of the plants assessed have a program or policies in place that ensure actual root cause will be determined when a failure occurs. Not surprisingly, 64 % of the plants assessed have already experienced failures, or display obvious symptoms of severe thermal transient damage in the superheater, reheater, or economizer (Table 2). The only way to be sure that the corrective actions taken will prevent a tube failure from recurring is to remove the failure site, have the actual failure mechanism identified via a metallurgical laboratory analysis, and then determine the root cause of the failure.

Taking the additional forced outage time to remove the failed section of tube is not a trivial matter. However, failing to do so is gambling with the unit's future reliability and maintenance costs. A tube failure prevention plan should be developed and implemented early in the unit's life – hopefully prior to any tube failure. The time for plant

Thermal transient factors assessed	Plant										
	A	B	C	D	E	F	G	H	I	J	K
Tube failure root cause program in use?	No	No	No	No	No	No	No	No	No	No	No
Routine attemperator inspection program in use?	No	No	No	No	No	No	No	Yes	No	Yes	No
Symptoms of severe thermal transients in SH (bowed tubes, failed tubes, oxide spalling)?	Yes	Yes	No	No	No	No	No	No	Yes	Yes	Yes
Symptoms of severe thermal transients in RH (bowed tubes, failed tubes, oxide spalling)?	No	No RH	No RH	No	Yes	No	No	No	Yes	No RH	No RH
Symptoms of large thermal transients in economizer (stretched or failed tubes)?	No	Yes	No	No	Yes	No	Yes	No	No	No	No
Drain pipes too small?	Yes	Note 1	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Blowdown vessel elevated above headers?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
Drain pipes have continuous downward slope?	No	No	No	No	No	No	No	No	No	No	No
Drains from different pressure levels combined?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Drain operation based upon reliable condensate detection?	Press	Press	No	Temp	Temp	Temp	Press	Press	Temp	No	No
Drains located near SH/RH header ends?	No	No	No	No	No	No	No	No	No	No	No
Drains opened prior to purge?	Yes	Yes	Yes	No	No	No	No	No	Yes	Yes	Yes
Drains opened during purge?	Yes	No	Yes	No	No	No	No	No	Yes	Yes	Yes
Drain valves operate automatically?	No	No	No	Yes	Yes	Yes	Yes	Yes	No	No	No
Cold reheat piping sloped downhill in direction of steam flow?	No	No RH	No RH	Yes	Yes	Yes	No	Yes	Yes	No RH	No RH
Condensate migration evident from DCS data in SH?	Yes	No plots	No	Yes	Yes	Yes	Yes	Yes	Yes	No plots	No
Condensate migration evident from DCS data in RH?	Yes	No RH	No RH	No	Yes	Yes	No	Yes	No	No RH	No RH
Attemperator leakage/overspray can flow directly into heating coil?	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes
Spray control valve integral with spray nozzle?	No	No	Yes	No	Yes	Yes	No	Yes	No	No	No
Simple feedback loop used for attemperator control?	Yes	No	No	Yes	No	No	No	No	Yes	No	No
Sufficient upstream or downstream straight pipe length?	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes
Manual manipulation of outlet steam temperature setpoint?	Yes	No	No	No	No	No	No	No	Yes	No	No
Manual control of attemperator spray valve?	Yes	No	No	No	No	No	No	No	No	No	No
Intermittent attemperator operation?	No	No	No	No	No	No	No	Yes	Yes	No	No
Overspray conditions evident from DCS data in SH?	Yes	No plots	No	Yes	No	No	No	No	No	No plots	No

Table 2:
Thermal transient factors for the HRSGs assessed.
SH superheater; RH reheater
Note 1: No drain sizing calculations performed on this class of unit from which to determine whether existing drains are adequate.
(Table to be continued on page 137.)

(Table 2 continued)

Thermal transient factors assessed	Plant										
	A	B	C	D	E	F	G	H	I	J	K
Overspray conditions evident from DCS data in RH?	Yes	No RH	No RH	No	No	No	No	No	No	No RH	No RH
Attemperator control instability evident from DCS data in SH?	No	No plots	No	Yes	Yes	Yes	No	No	Yes	No plots	No
Attemperator control instability evident from DCS data RH?	No	No RH	No RH	No	No	Yes	No	No	Yes	No RH	No RH
Outlet steam over temperature conditions evident from DCS data in SH?	Yes	No plots	No	Yes	No	No	No	No	No	No plots	No
Outlet steam over temperature conditions evident from DCS data in RH?	Yes	No RH	No RH	Yes	No	No	No	No	No	No RH	No RH
Economizer drains share second isolation valve?	Yes	Yes	No	Yes	Yes	Yes	No	No	Yes	No	No
Cross flow economizer inlet row with baffles in common headers?	Yes	No	No	Yes	Yes	No	No	Yes	No	No	Yes
Thermal deaerator or economizer recirculation used for startup?	No	No	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes
Shutdown SH or RH temperature ramp rate limit established for headers?	No	Yes	No	No	Yes	No	Yes	Yes	No	Yes	Yes
Startup SH or RH temperature ramp rate limit established for outlet headers?	No	Yes	No	No	No	No	No	No	No	Yes	Yes
HP drum pressure ramp rate limit established for startup?	Yes	Yes	No	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
SH and RH steam cooled during shutdown?	No	Yes	No	No	Yes	No	Yes	No	No	Yes	Yes
Prudent SH or RH temperature ramp rate limit exceeded during shutdown?	Yes	No	No	Yes	No	Yes	No	Yes	Yes	No	No
Prudent SH or RH temperature ramp rate exceeded during startup?	No	No	No	Yes	Yes	Yes	Yes	No	Yes	No	No
Prudent HP pressure ramp rate exceeded during startup?	No	No	No	Yes	No	Yes	Yes	No	No	No	No
Use of ETM on shutdown?	No	Note 2	Note 2	No	Note 2	Note 2	Note 2	Note 2	No	Note 2	Note 2
Use of ETM during lag in unit startup?	No	Note 2	Note 2	Yes	Note 2	Note 2	Note 2	Note 2	No	Note 2	Note 2

Table 2:
Thermal transient factors for the HRSGs assessed.
SH superheater; RH reheater
Note 2: These factors are only applicable to units with the GE 7FA/9FA GT.

Explanation of colors used in Table 2:

Red indicates that the unit is subject to undesirable thermal transients due to this factor.

Green indicates that the unit is not subject to undesirable thermal transients due to this factor.

Yellow indicates that the unit may be subject to undesirable thermal transients due to this factor.

White indicates that the factor is not applicable to this unit.

managers, asset managers, operations directors, general managers, and executives to objectively agree on the relative priorities of longterm unit reliability and maintenance cost versus short term revenue and power production needs is before failures occur while the unit is running well – not during the forced outage when the unavailability and lost revenue meters are running.

Such a plan need not be complex, but should include the following key elements to be executed during each tube failure event: a) prior agreement, throughout the management chain, that a material sample containing the failure site will be removed from the HRSG for metallurgical analysis; b) root cause, as contrasted with apparent cause or failure mechanism, must be determined for each tube failure event; c) each failure location within the HRSG must be precisely recorded using an unambiguous orientation scheme (failure site orientation (up/down, gas flow direction, etc.) should also be recorded and stored); d) a modest supply of spare HRSG tubing in appropriate sizes and materials, including a few bends, should be placed in inventory and kept in good condition.

CYCLE CHEMISTRY, CORROSION AND FAC IN HRSGs

There are a number of cycle chemistry issues important in preventing pressure part failures in multiple-pressure combined cycle systems. Among these, two major areas of concern that are influenced by the cycle chemistry treatment regime are flow-accelerated corrosion (FAC) and under-deposit corrosion (UDC).

Both single- and two-phase FAC can occur equally in horizontal and vertical gas path (HGP and VGP) HRSG tubing, headers, risers and the LP drum. So during an assessment it is important to recognize exactly which type can occur in each circuit because the potential solutions are different for each type. FAC in combined cycle plants was recently reviewed [1] and included numerous examples of the different types and morphologies common in HRSGs. Overall some of the regions of concern are: a) economizer/preheater tubes at inlet headers; b) economizer/preheater tube bends in regions where steaming takes place; c) vertical LP evaporator tubes on HGP units especially in the bends near the outlet headers; d) LP evaporator inlet headers which have a contortuous fluid entry path and where orifices are installed; e) LP riser tubes/pipes to the LP drum; f) LP evaporator transition headers; g) IP economizer inlet headers; h) IP economizer outlet headers especially in bends near the outlet headers in units which have steaming; i) IP riser tubes/pipes to the IP drum; j) IP evaporator tubes on triple-pressure units which are operated at reduced pressure; k) LP drum internals; and l) horizontal LP evaporator tubes on VGP units especially at tight hairpin bends.

UDC in HRSGs occurs exclusively in HP evaporator tubing. The three UDC mechanisms, hydrogen damage, acid phosphate corrosion and caustic gouging, all require heavy deposits and a concentration mechanism within those deposits. For hydrogen damage the concentrating medium is usually chloride which enters the cycle through condenser leakage. Acid phosphate corrosion relates to a plant using phosphate blends which have sodium to phosphate molar ratios below 3 and/or the use of congruent phosphate treatment using one or both of mono- or disodium phosphate. Caustic gouging involves the concentration of either NaOH used above the required control level within caustic treatment or the ingress of NaOH from regeneration of ion exchange resins. Deposition and the UDC mechanisms occur on both vertical and horizontal HRSG HP evaporator tubing. On vertical tubing the deposition concentrates on the ID crown of the tube facing the GT. It nearly always is heaviest on the leading HP evaporator tube in the circuit as these have the areas of maximum heat transfer. The UDC mechanisms occur in exactly the same areas. On horizontal tubing both deposition and the UDC mechanisms occur on the ID crown facing towards or away from the GT. Damage usually occurs on the side facing away from the GT when poor circulation rates, steaming or steam blanketing occur. These can lead to stratification of water and steam and subsequent heavy deposition in a band along the top of the tubing.

Thus although the FAC and UDC mechanisms occur at opposite ends of the plant, they are linked by the corrosion products generated by the corrosion/FAC mechanisms in the low pressure parts of the HSRG which subsequently deposit in the HP evaporator tubing and form the basis of the under-deposit corrosion damage mechanisms. This link forms the main focus of the cycle chemistry assessments in the plants, which identify the precursors or active processes, which if left unaddressed, will eventually lead to failure/damage by one or both mechanisms. Acting proactively will remove the risk for both.

Analysis of Table 3, which shows the cycle chemistry treatments and key indicators for the very diverse group of plants assessed, will identify a number of key factors that can be seen to be predominant for the two mechanisms.

For FAC

FAC is the leading cause of damage and failure in HRSGs. The control of FAC in combined cycle/HRSG plants usually takes a three-pronged approach of: a) operating with an oxidizing chemistry, all volatile treatment – oxidizing (AVT(O)) or oxygenated treatment (OT), to control the single-phase component; b) operating with an elevated pH (at least 9.8) to control the two-phase component; and c) monitoring (analyzing the total iron concentration in the condensate, feedwater, and in each drum) to verify/confirm whether these approaches are successful.

Plant	Is reducing agent used? / Ammonia/amine	Are LP, IP and HP independently fed?	Drum treatments	Feedwater Fe [µg · kg^{-1}]
A	Yes (Carbohydrazide) / Amine blend	No – LP drum feeds IP/ HP feedpump	LP: None IP and HP: Phosphate blend	Not known
B	No (from startup) / Ammonia	No – LP drum feeds HP feedpump	LP: None HP: Trisodium phosphate	< 5
C	Yes (Proprietary) / Amine blend	No – LP drum feeds IP/HP feedpump	LP: None IP and HP: Congruent phosphate blend	Not known
D	No / Ammonia (pH 9.2–10.2)	No – LP drum feeds IP/HP feedpump	LP, IP and HP: None	2–8
E	No (after first two years) / Ammonia (pH 9.3–9.4)	No – LP drum feeds IP/HP feedpump	LP: None IP and HP: Trisodium phosphate	5/6
F	No (from startup) / Ammonia	Yes – from deaerator	LP: NaOH (pH 9.5–9.7) IP and HP: None (pH 9.6–9.7)	10
G	No (removed after FAC) / Ammonia (pH 9.6–9.8)	Yes – from deaerator	LP: NaOH (1 mg · kg^{-1}) IP and HP: None	< 2
H	No (from startup) / Ammonia (pH 9.8)	Yes – after preheater	LP: NaOH IP and HP: None	~10
I	No (after first 2 years) / Ammonia (pH 9.8)	Yes – from deaerator	LP, IP, HP: Trisodium phosphate (pH 9.5–9.9)	< 1
J	Yes /	No – LP drum feeds IP/HP feedpumps	IP and HP: Phosphate	Note 1
K	/ Amine blend	No – LP drum feeds IP/HP feedpump	LP, IP, HP: Phosphate blend of mono-, di- and trisodium phosphate	Note 1

Plant	Drum Fe [µg · kg^{-1}]	% of SI fundamental instruments	Tube samples taken from HP evaporator?	FAC inspections conducted?	Has drum carryover been measured?
A	Not known	33 %	No	No	No
B	LP: Not known HP: 25–160	60 %	No	Yes	No
C	Not known	0 %	No	No	No
D	Not known	85 %	No	No	No
E	Not known	60 %	No	No	No
F	LP: > 30, IP: 10, HP: 10	53 %	No	Yes for preheater	No
G	LP: 20–50, IP: 7–8, HP: < 5	58 %	No	Yes on IP risers	No
H	LP: > 100, IP: < 10, HP: < 5	81 %	No	No	No
I	Not accurately known	66 %	No	Yes on economizer bends	No
J	Note 1	Note 1	Note 1	Note 1	Note 1
K	Note 1	0 %	Note 1	Note 1	Note 1

Table 3:
Key cycle chemistry factors for plants assessed.
Note 1: Cycle chemistry assessment not conducted.

The 11 detailed assessments from a wide variety of plant designs and operating conditions have revealed:

- Reducing agents (oxygen scavengers) are used in about 37 % of the plants. This figure is reduced from previous surveys, which indicated that about 50 % of HRSGs are still using reducing agents [5].
- About 37 % of the plants assessed have the LP evaporator/drum independently fed and not feeding the IP and HP circuits, and thus operators are able to address single- and two-phase FAC uniquely by increasing the pH and adding a solid alkali such as trisodium phosphate or NaOH.
- About 40 % of the LP circuits add trisodium phosphate or NaOH.
- About 36 % do not know the iron levels in the condensate/feedwater and 72 % do not know the levels in the LP drum. In many cases where iron levels are measured the organization uses a technique which is either only applicable for soluble iron or does not have sufficient low level capability for total iron measurement.
- A very low percentage of plants (≈37 %) had actually made any detailed NDE[1] assessments of FAC in the lower pressure circuits, and those that had were essentially concentrated on individual circuits where failures or damage had previously been identified.

Many organizations, including those within these assessments, try to address both single- and two-phase FAC at the same time despite it being recognized that the optimum process is to address each individually [1] as they are controlled by different parts of the cycle chemistry envelope.

Do plants have single-phase FAC under control? What indicators are used during the assessment for single-phase FAC? To answer these questions it is necessary to give proper attention to two factors. The first factor is to ensure that a reducing agent is not used in the cycle during any periods of operation or shutdown. It has been well established for about 20 years that single-phase FAC in HRSGs is controlled by the oxidizing-reducing potential (ORP) of the condensate and feedwater. In HRSGs the potential should always be oxidizing; this means operating <u>without</u> a reducing agent [1]. The second factor considered during assessments is to identify whether sufficient oxidizing power is available to passivate all the single-phase locations. The indicators the authors look for are: a) the actual level of oxygen at the condensate pump discharge (CPD) and in the feedwater at the feedpumps; and b) the color of the LP and IP drums. Many HRSG plants have excellent air in-leakage control with only between 5–10 $\mu g \cdot kg^{-1}$ oxygen being identified at the CPD. The oxygen level would of course be much lower after a deaerator if one is installed in the plant prior to the LP economizer/preheater, and in the feedwater if the feedpumps are fed by the LP drum (which may include an integral deaerator). In association with these plants there is clearly inadequate passivation of the LP drum (and maybe the IP drum). The LP and IP drums in these cases will have a red appearance which is "patchy" and the grey/black magnetite which can be seen showing through is usually associated with low levels of oxygen (2–6 $\mu g \cdot kg^{-1}$). This means there is still magnetite exposure with incomplete conversion to red FeOOH and associated higher iron levels. The level of low oxidizing power (low oxygen) may not be able to satisfactorily passivate all the single-phase flow locations in the economizer circuits as well as the LP and IP evaporator circuits and drums. The possibility of increasing the level of oxygen may need to be investigated to provide better single-phase protection while being cognizant of oxygen levels in other areas of the HRSG. Possible methods include closing the vents on the deaerator (if included in the cycle) or actually adding controlled amounts of oxygen at the deaerator outlet (suction of the boiler feedpumps). Of course if there are intermittently high levels of oxygen in the condensate, then this will preclude closing the deaerator vents. Clearly an aggressive air in-leakage approach will be needed. Overall these indicate that the low level of oxygen in the LP drum is not adequate to provide full single-phase FAC protection. Monitoring of total iron in the LP (and IP) drums is the main indicator of the extent of passivation with the target being to have total iron levels of less than 5 $\mu g \cdot kg^{-1}$ in agreement with the "Rule of 2 and 5" for corrosion products (< 2 $\mu g \cdot kg^{-1}$ total iron in the condensate/feedwater and < 5 $\mu g \cdot kg^{-1}$ in each drum).

Do plants have two-phase FAC under control? What indicators are used during the assessment for two-phase FAC? As two-phase FAC cannot be influenced by oxidizing power (oxygen level) it is important to identify first the areas where two-phase, steaming and streaming flows can occur, and secondly whether the pH can be locally increased at these locations. Once a plant is satisfied that the single-phase flow areas are adequately passivated as indicated by the LP and IP drums having an even red surface color (below the water level), the monitored total iron levels can be assessed in terms of two-phase FAC. Total iron values in units assessed indicating two-phase FAC were typically greater than 20 $\mu g \cdot kg^{-1}$ in the LP and IP drums, with some up to 100 $\mu g \cdot kg^{-1}$. The areas affected are usually: a) preheater/LP economizer bends or areas where steaming occurs; b) LP evaporator bends near the outlet header where two-phase flow occurs; c) LP risers to the LP drum; d) IP economizer bends or areas where steaming occurs; e) IP risers to the IP drum; f) hairpin bends in horizontal LP evaporator tubing in VGP units; and g) LP drum internals. Steaming can easily be identified in these areas by installation of thermocouples on the appropriate location. In very few cases (< 20 % of the units assessed), the manufacturer has "armored" some of these areas with chromium-containing tubes and pipes (typically 1–1.25 % Cr alloys); the usual areas are LP and IP evaporator outlet tubes with bends, and the risers.

1 non-destructive evaluation

In cases where the single-phase areas have been passivated by oxidizing treatments but monitored total iron levels remain high, two options are available to attempt to reduce and control the two-phase FAC chemically: a) increasing the pH of the condensate/feedwater in steps up to 9.8 with ammonia; and/or b) elevating the LP and IP drum pH to 9.8 by controlled additions of trisodium phosphate or NaOH. A further option related to a) is to use an amine, but in this case very careful monitoring of steam must also be conducted to ensure steam turbine manufacturers' cation conductivity limits are understood. Option b) can only be adopted for the LP drum in the cases where the IP and HP drums are not fed by the LP drum. Further, if option b) is adopted using increased levels of NaOH in the LP and/or IP drums, it will be of paramount importance to monitor steam sodium (saturated and HP/IP), and the total carryover from the drums should be measured as discussed below. Whichever option is used, monitoring of total iron is the main indicator with the goal being to meet the "Rule of 2 and 5".

It must be recognized that optimized cycle chemistry treatments alone cannot always address the combination of single- and two-phase FAC in HRSG circuits. If after addressing single- and two-phase FAC separately and conducting the well understood sampling, chemistry and monitoring steps suggested above the iron levels do not approach the "Rule of 2 and 5", then the only options remaining will be a combination of inspection/NDE and replacement of the susceptible areas with tubing/piping containing 1–1.25 % Cr [1].

For Under-Deposit Corrosion

One of the most important proactive items for plants is to ensure that the HP evaporator does not experience one of the under-deposit corrosion mechanisms – with the most important being hydrogen damage. This takes on added importance when the plant is cooled by seawater or other sources such as river water, reclaimed water, or lake water with high levels of chloride ($> 10\ mg \cdot kg^{-1}$), and has no condensate polisher in the cycle. In the assessment process particular attention is given to the two key areas for hydrogen damage: a) deposits in the HP evaporator; and b) ingress of contaminant (chloride) into the HP evaporator under conditions when serious deposits are present, and the HP evaporator chemistry treatment is inadequate.

The 11 detailed assessments from a wide variety of plant designs and operating conditions have revealed (Tables 1 and 3):

- Only about 30 % of the plants know the iron levels in their HP evaporator/drum and thus whether these meet the "Rule of 2 and 5".
- None of the plants had taken HP evaporator tubing samples from the hottest row for analysis of the internal deposits.
- Most of the plants did not have an adequate level of fundamental instruments alarmed in the control room that could uniquely identify for the operators when contamination in the HRSG HP evaporator is serious.

So, are plants proactively addressing the possibility of under-deposit corrosion? Are indicators being used to determine if a plant has adequate instrumentation coverage? It is obvious that the answer here is no, as none of the plants was trying to associate a relationship between the total iron levels in the LP circuits and levels of deposit in the HP evaporator. None had taken HP tube samples for metallurgical examination to assess the level of internal deposits, their morphology and their composition (via chemical and metallographic analyses). It was suggested at each plant that the tube samples should be taken from the lead (hottest) tube row of the HP evaporator section as near to the outlet of the circuit as possible. On units with vertical tubing (HGP) a secondary location is near the bottom of this lead tube. If possible, samples should be taken from a tube adjacent to a side wall or the gap between side-by-side modules where exhaust gas bypassing results in greater heat transfer.

One of the authors has been developing a data base of deposit analyses from a much wider suite of HRSGs worldwide to start understanding how deposits in HP evaporator tubes are related to the operating cycle chemistry. Particular attention in developing this data base has been given to three aspects: a) the "normal" deposit density ($mg \cdot cm^{-2}$); b) optical metallography to determine the porosity and morphology of the deposits as well as the indigenously grown magnetite; and c) elemental mapping across the deposits to determine if any reaction/corrosion products are being formed within or beneath the deposit. This will be published soon, but as expected for some time, it is already clear that optimum (minimum) deposits occur with optimum chemistry control. This is defined as chemistry which: a) controls single-phase FAC in the condensate/feedwater and LP evaporator with an oxidizing treatment (AVT(O)); b) controls two-phase FAC in the same locations by using either trisodium phosphate or NaOH in the LP drum if allowed as mentioned above (37 % of the units assessed, Table 3); and c) adds nothing to the HP drum or a minimum amount of only trisodium phosphate (TSP) or NaOH. It is also very clear that deteriorating (thickening) deposits occur when an HRSG is operated outside of this envelope by the addition of reducing agents and amines in the condensate/feedwater, and mixtures of phosphates (other than TSP) and NaOH to the HP drum. This factor of knowing, as early in life as possible, the deposition rate onto the internal surfaces of HP evaporator tubes by extracting and analyzing their deposits comprehensively is tremendously important, especially for plants cooled by seawater. It helps in assessing the risk of UDC in the case of contaminant ingress, and more importantly allows the HRSG to be cleaned at the optimum time.

Assessments focus on the fundamental level of instrumentation needed for every plant because of the importance in addressing the UDC mechanism. The fundamental level of instruments is the minimum key level of instruments which can uniquely identify cycle chemistry problems on the combined cycle/HRSG unit. Table 4 shows an example of the fundamental level of instrumentation for a multi-pressure HRSG operating with an oxidizing treatment in the condensate and feedwater (AVT(O)) and only trisodium phosphate being added to the drums. It is quite alarming to record the relatively low level of needed instrumentation on some units (Table 3) when this provides the ability to a plant for adequate or increased protection to the HRSG, especially the HP circuit, in the event of contaminant ingress. A key instrument for phosphate treated units is a phosphate analyzer on the HP drum. This will help to keep this circuit optimized continuously, as opposed to infrequently by grab sampling. To clearly identify a specific contaminant ingress situation it is imperative that cation conductivity monitoring is employed on the HP drum. It has been found many times around the world that relying on a pH monitor to record a pH depression in contaminant situations on the HP drum does not provide sufficient security when only small condenser "weepers" occur. In many cases these go undetected, or in others operating decisions are made to continue operating the unit with on-going contamination which has been "corrected" by chemical addition. While none of the assessed plants had this feature, it is suggested that on seawater cooled plants without condensate polishing the risk of UDC can be lowered by having more than the fundamental level of instrumentation by addition of an on-line chloride analyzer on the HP drum for added security.

Another important item regarding instrumentation noted during the assessments is the disturbing trend of plants relying heavily on grab samples. A common trend is the large number of grab sample analyses conducted daily, every shift, or every week or two by the operating or chemistry staff. By using a full complement of Structural Integrity Associates' (SI's) Fundamental Level of Instrumentation such as the example in Table 4, most of these could be eliminated, better continuous control of cycle chemistry could be provided, and significant time could be saved for the operators. For example in many plants, grab samples for silica are currently taken at multiple locations (up to six) on each HRSG once per week. This is in addition to a number of on-line silica measurements on each unit!

Other Important Cycle Chemistry Items Included in the Assessments

Carryover from the HP, IP and LP drums into steam

As Table 3 illustrates none of the organizations have comprehensive programs for monitoring carryover; in fact the percentage of total carryover from any drum was not known by any organization. However to protect the steam

Parameter	Sample Locations
Cation conductivity	Condensate pump discharge (CPD) Condensate polisher outlet (if installed) (CPO) Feedwater/economizer inlet (EI) Each boiler drum/blowdown (BD) in multi-pressure system High pressure steam (HPSH) or reheat steam (RH)
Specific conductivity	Makeup (MU) Each boiler drum/blowdown (BD) in multi-pressure system
pH	Each boiler drum/blowdown (BD) in multi-pressure system
Sodium [1]	Condensate pump discharge (CPD) Condensate polisher outlet (if installed) (CPO) or economizer inlet (EI) High pressure steam (HPSH) or reheat steam (RH)
Dissolved oxygen	Condensate pump discharge (CPD) Feedwater/economizer inlet (EI)
Phosphate	Each boiler drum blowdown (BD) where phosphate is added

Table 4:
An example of SI's fundamental level of instrumentation for an HRSG multi-pressure drum unit with the condensate and feedwater on AVT(O) and the evaporators operating with only trisodium phosphate (TSP) additions.

[1] Sodium may not be required on the CPD sample for units with an air-cooled condenser.

turbine, the total carryover from each of the drums should be measured on about a six month basis to ensure the integrity of the drum separation internals and the operational drum levels. This is a simple test, which requires concurrent sampling for sodium in the drum and in the saturated steam. Details of the process are provided in a recent IAPWS Guidance Document [7]. If trisodium phosphate or NaOH is added to the drums, then there shouldn't be a need to add any further sodium to the drums to conduct the test. It is vital to know the carryover from each drum to provide protection to the steam turbine.

Shutdown protection Another item included in the assessment process is whether the plant provides protection to the HRSG and steam turbine during shutdown periods. Most of the units within the current assessment have facilities to provide nitrogen blanketing to the HRSG during shutdown to prevent the initiation and growth of pits on internal HRSG surfaces. However, only one of the units had an operating dehumidified air system to provide protection to the steam turbine during shutdown periods. Most combined cycle/HRSG organizations need to give serious consideration to installing dehumidified air for the LP steam turbine as this is the most important method to prevent failures in the future in the phase transition zone (PTZ) of the LP turbine [8]. This should take on added emphasis for units if the number of long shutdown periods (> 3 days) increases during each year for the steam turbine.

THERMAL TRANSIENTS IN HRSGs

Thermal transients are unavoidable if the HRSG is to be started and stopped, as it must. This presents no problems as long as: a) the OEM accurately anticipates the number and severity of thermal transients to which the HRSG will be exposed; b) the HRSG is competently designed and fabricated to withstand the anticipated transients; c) neither the OEM, EPC contractor, nor owner/operator introduces features or operating procedures that result in significant unanticipated thermal transients.

HGP HRSGs are constructed with tubes arranged vertically in "harps". These harps are rigid structures requiring that adjacent tubes remain at similar temperatures if severe thermal-mechanical fatigue damage and premature failure is to be avoided. Even with the use of advanced high creep strength materials, HRSGs operating at high pressure and temperature must be equipped with HP drum, HP superheater, and sometimes reheater outlet headers and piping with sufficiently thick walls so that careful management of heat-up and cool-down rates is required if internal cracking is to be avoided.

VGP HRSGs are arranged with banks of serpentine tubes, positioned horizontally, and supported along their length by tube-support plates. This tube arrangement is considered by some to be more flexible than the harp arrangement used in HGP HRSGs. While this may be true in some cases, VGP HRSGs are not immune to thermal transient induced tube failures. Discussion of these failures and their root causes is beyond the scope of this paper since the current assessments did not include any VGP units.

As with cycle chemistry, there are many thermal transient issues that must be managed effectively if excessive thermal-mechanical fatigue damage is to be avoided. Among these there are three that stand out as having caused a large number of tube failures, or which have a high potential to cause cracks in thick-walled components: 1) inadequate drainage of superheaters and reheaters; 2) interstage attemperator overspray, spray water leakage, and erroneous operation; 3) quenching of economizer/preheater inlet sections.

Table 2 shows the indicators of ineffective or incomplete drainage, damaging attemperator performance, LP economizer quench, and operating practices known to cause damaging thermal transients in thick pressure parts for the plants assessed. Analysis of this table will identify a number of key factors that can be seen to predominate in the three areas of concern.

For Superheater and Reheater Drainage

HP superheater and reheater drain system designs and operating practices that do not remove all condensate prior to initiation of steam flow during cold, warm and hot startups are unable to protect the superheater and reheater tube-to-header connections, header bores and nozzle-to-header connections from severe thermal fatigue damage. Such damage has resulted in many premature tube failures, and can be expected to result in header bore cracking and/or nozzle-to-header weld failure.

A large quantity of condensate forms in the superheaters during the prestart purge when superheaters and reheaters behave like large air-cooled condensers. It is critical that this condensate be drained from the superheater and reheater as fast as it forms and not be allowed to accumulate. During all types of startups superheater tubes heat up to near exhaust gas temperature between GT light-off and establishing initial steam flow though the tubes. Undrained condensate will migrate selectively through some tubes as steam flow is initiated, quenching (and shrinking) these tubes. Shrinkage of these tubes, relative to still hot neighboring tubes, results in a large bending stress at the tube-to-header connection and severe thermal fatigue damage. After shutdown thick-walled headers and steam piping remain hot for long periods. During hot starts condensate carried by steam flow will enter and quench the still hot upper headers and steam piping. Cracks in the header bore and outlet nozzle-to-header welds may result from such quenching.

The 11 detailed assessments have revealed:

- 91 % of the plants assessed have drainpipes too small to remove the quantity of condensate formed during the purge cycle in the time available prior to steam flow commencing. Detailed calculations to determine condensate formation rates in superheaters and reheaters under various startup conditions, and the drainpipe size required to remove it, have been performed for a number of HRSGs in the past. The authors use this information in assessing drainpipe size. As an example, each final superheater harp in the typical F-Class HRSG requires the equivalent of three 5-cm (2-inch) drainpipes to effectively remove condensate.

- 91 % of the plants assessed have their flash tank positioned at an elevation above the lower headers and none have drainpipes routed with a continuous downhill slope to the tank. During cold and warm starts from zero pressure it is impossible for condensate to flow uphill to the tank or through upwardly flowing sections of drainpipe. By the time sufficient pressure is generated to do so, and if cascading bypass valves are opened early to steam cool the reheater as they should be, steam flow has already moved the accumulated condensate through the superheater and reheater.
- 100 % of the plants assessed have drainpipes from superheater or reheater sections that operate at different pressures interconnected [9]. For example, when steam is flowing the pressure in the primary superheater (the superheater upstream of the attemperator relative to steam flow) must be higher than that in the secondary superheater (the superheater downstream of the attemperator relative to steam flow). If the drains from these sections are interconnected prior to entering the flash tank, condensate will flow from the primary superheater into the secondary superheater. While some condensate from the primary superheater may also flow to the flash tank (if its elevation is not too high), the secondary superheater will not drain and often has its condensate level rise. Changes to the ASME Boiler & Pressure Vessel Code in 2007 [11] mandate that interconnection of drains from superheaters or reheaters of different pressures must not be prevented from flowing, or allowed to back-flowing, due to backpressure in the common manifold, flash tank, etc. While useful in helping operators purchase new units with more effective drains, thoughtful attention to drain and flash tank arrangement is required if the desired results are to be realized.
- None of the plants assessed are equipped with a reliable means of determining when condensate is actually present in the superheater/reheater and when drain valves should be open. Nor can they detect when the superheater/reheater has been successfully drained and drain valves should be closed. 55 % of those assessed have no automatic means of drain operation. Of those with some form of automation, 50 % use thermocouples installed in drainpipes to determine when to close drain valves, and 50 % close the valves at predetermined pressures. While these methods might work as intended during startups from one initial pressure condition, neither can accomplish effective draining over the wide range of initial pressure conditions from which a cycling HRSG must be started. A significant challenge in effective drain control stems from needing very large drainpipes to remove condensate fast enough during starts initiated from zero pressure when only gravity head is available to move the water, and avoiding excessive release of steam through these large pipes during starts initiated from high pressure. For example, drainpipe thermocouples might be effective during a startup from zero pressure when it is possible to leave the drain valves open prior to and during the purge, then close them when the thermocouple detects superheated steam passing through the pipe. However, during a start from initial high pressure the drain valves can't be left open throughout the purge without risk of depressurizing the HP system (if the drainpipes are large enough to work at zero pressure). The drainpipe thermocouple is useless for controlling the drain valves during the critical prestart and purge periods since both condensate and steam are at the prevailing saturation temperature. If the drain valves are not opened until the GT is fired and the drainpipe thermocouple can be used, there is a good chance that the accumulated condensate will not have completely drained before steam flow commences. The preferred method of controlling drain valves during starts initiated from any pressure is through the use of a level detecting drain pot on each superheater and reheater section that operates at a different steam pressure [4,10].
- None of the plants assessed have drains located near the ends of the superheater and reheater headers. When new and when in the cold condition most harps hang straight with their lower header level. After some years of operation lower headers may become tilted as harps become distorted. During hot starts lower headers become "humped" due to top-to-bottom temperature difference (condensate laying in the header cools the bottom, shrinking it, relative to the top) [4]. These conditions result in condensate being unable to reach a drain positioned in the center of the header. Such trapped condensate will migrate up adjacent tubes when steam flow commences regardless of drainpipe size and operating procedures. The addition of a drain near each end of the header prevents condensate being trapped.
- 55 % of the plants assessed open the drains prior to initiating the startup to ensure the superheaters and reheaters are dry. 45 % open the drains during the purge to drain condensate as it is forming. Waiting until the GT fires to open drain valves significantly increases the time required to remove all condensate and increases the risk that some will remain when steam flow commences.
- 29 % of the plants assessed that have a reheater are equipped with cold reheat piping that slopes uphill in the direction of steam flow from HP turbine to HRSG. This arrangement has been found in many cases to result in undrained condensate passing from the cold reheat pipe into the primary reheater [4]. See Figure 1.

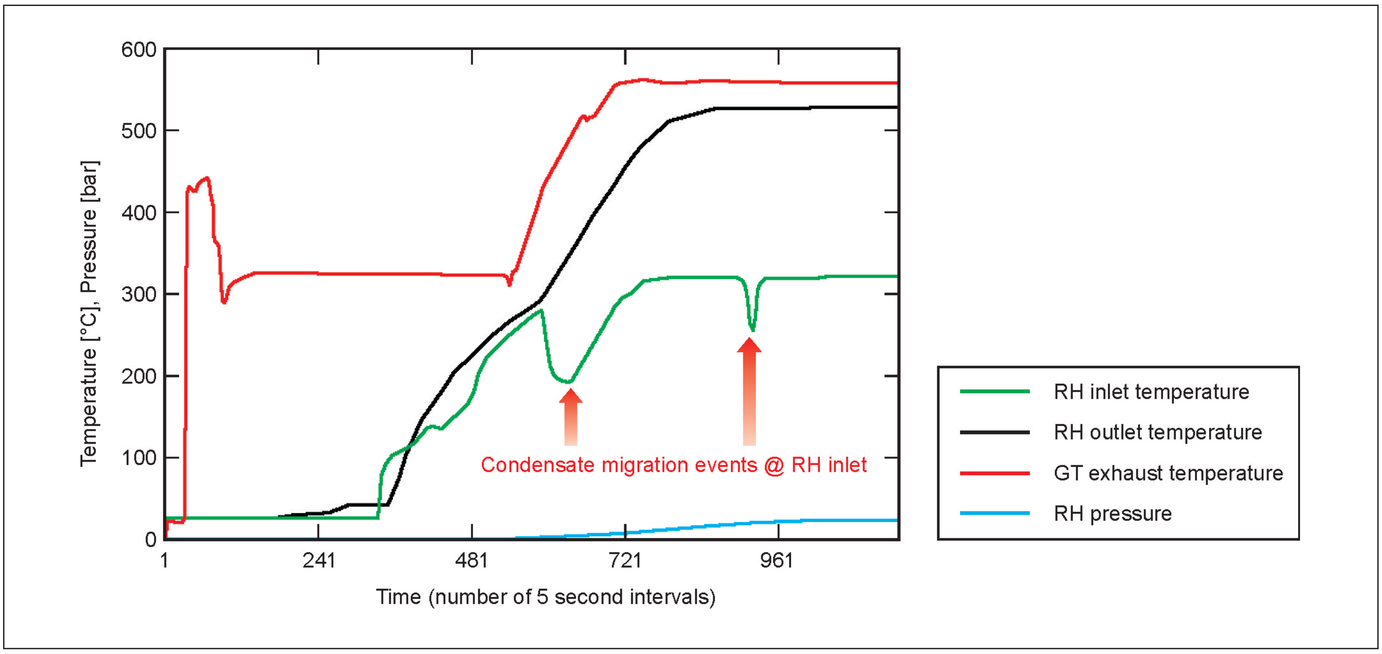

Figure 1:
The cold reheat pipe in this plant is sloped uphill from the steam turbine to the HRSG. Condensate formed in the pipe during warming is swept into the reheater inlet as indicated by the large drops in reheater inlet temperature.

Are superheaters and reheaters being drained effectively? Migration of undrained condensate cannot normally be observed via normal plant instrumentation. Permanent steam temperature sensing elements are relatively slow to respond to sudden temperature changes. Small slugs of condensate pass these temperature elements too fast to register a change in temperature. Unfortunately these fast moving slugs of condensate do cause significant changes in the temperature of the relatively thin-walled superheater and reheater tubes, and in the inner surface temperature of hot headers, as they pass through. It is usually necessary to install a number of temporary tube temperature thermocouples in the superheaters and reheaters to confirm the presence of condensate migration and quantify its severity [12]. Only very severe condensate migration events last long enough to register on the DCS steam temperature instrumentation.

- 78 % of the plants assessed showed evidence of condensate migration via DCS plots of permanent thermocouples located near the attemperator. Figures 1 and 2 show two such DCS data plots. The dip in temperature at the attemperator outlet in Figure 2 is indicative of severe condensate migration between the primary and secondary HP superheater. Likewise, the dip in temperature at the reheater inlet in Figure 1 indicates a large quantity of condensate passing from the cold reheat pipe into the primary reheater. Without the cost of installing temporary tube temperature thermocouples, it can be concluded that significant amounts of condensate are remaining in and migrating through the HP superheater and reheaters, and passing into the main steam and hot reheat piping during startups.
- 64 % of the plants assessed report superheater/reheater tube/header connection failures, obviously stretched tubes due to quenching, or spalling of external tube oxide due to high strain at the tube/header connection.

For Attemperation

The distribution of heat transfer surface area between the primary versus secondary superheater and reheater, the type of GT coupled to the HRSG, performance of the attemperator control system, the quality of attemperator hardware employed, and the attemperator piping arrangement are all critical in obtaining acceptable attemperator performance [13]. The introduction of unvaporized spray water into downstream harps causes damaging thermal transients. This is called overspray: defined as attemperator outlet steam temperature < 28 K (50 °F) above the prevailing saturation temperature.

The 11 detailed assessments have revealed:

- Only 18 % of the plants assessed perform routine inspections or preventive maintenance on their attemperators. Attemperators are notoriously unreliable and subject to severe thermal transients. A routine inspection program should be consistently executed. Work scope should include removal/inspection/repair of the spray nozzle, control valve, block valve and borescope inspection of the thermal liner and its attachment points. These inspections should be performed annually at minimum.

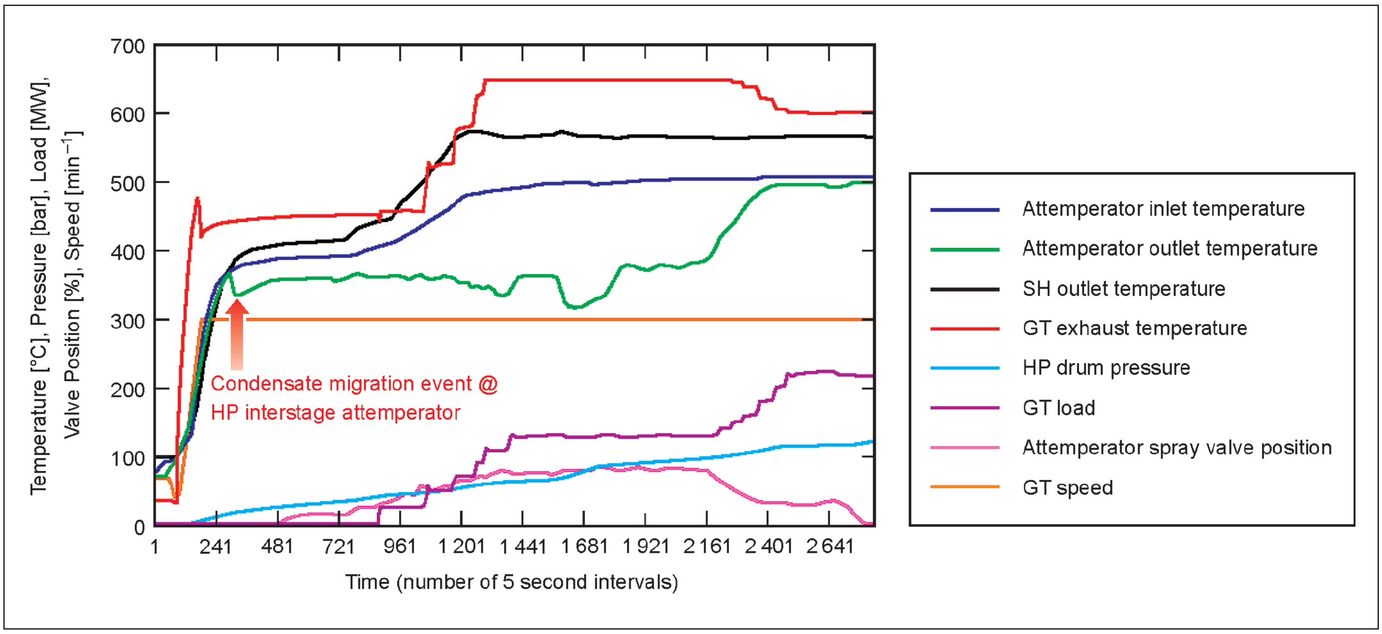

Figure 2:

Undrained condensate was carried by steam flow from the primary to secondary superheater as indicated by this large dip in attemperator outlet temperature. Only a large quantity of condensate will register like this on permanent plant instrumentation.

- 82 % of the plants assessed have attemperator piping arrangements that allow unvaporized, or leaking, spray water to flow directly into harps during low or zero steam flow conditions. When this occurs while the harp is hot, severe thermal-mechanical fatigue damage, and sometimes immediate tube failure, results [13]. Changes to the ASME Boiler & Pressure Vessel Code in 2007 [11] no longer permit these undrained attemperator pipe arrangements [10]. Existing plants with such arrangements can benefit from the addition of a second spray water block valve and tell-tail drain to reduce the risk of undetected block valve leakage.
- 36 % of the plants assessed are equipped with spray water control valves internal to the spray nozzle assembly. This configuration has proven to be very unreliable in cycling service and is no longer supplied by most HRSG OEMs.
- 27 % of the plants assessed utilize simple steam outlet temperature feedback loops for attemperator control. All of the plants with this control configuration have difficulty avoiding overspray conditions, maintaining outlet steam temperature within design limits, or manually controlling the attemperator setpoint in an attempt to compensate for the automatic control's inability to perform adequately [4]. Manual setpoint manipulation and manual spray valve positioning are dangerous workarounds. The thermodynamic complexity, the very long time delay for steam temperature changes to register on DCS readouts, and the speed with which temperature changes occur place consistently safe attemperator control without creating overspray conditions beyond the ability of even the best operator. The preferred attemperator control scheme utilizes two cascaded controllers with real-time enthalpy calculations performed around the attemperator. Plants equipped with the GE 7FA/9FA GTs also find it useful to add an anticipatory feature by incorporating GT fuel demand or inlet guide vane position into the attemperator control scheme.
- 18 % of the plants assessed experience attemperators coming into, and out, of service multiple times during startup. Intermittent attemperator operation exposes attemperator hardware, piping and superheaters/reheaters to avoidable and undesirable thermal transients. GT loading, GT exhaust temperature controls (exhaust temperature matching, ETM, on GE 7FA/9FA units), and attemperator controls should be coordinated to avoid the need for attemperation until GT exhaust temperature can no longer be held below 510 °C (950 °F). Once the attemperator is placed in service it should stay in service until no longer needed. New units should be designed so that attemperators remain in service continuously at minimum spray water flow to minimize thermal-fatigue damage to attemperator hardware.

Special consideration for attemperation in plants equipped with GE 7FA/9FA gas turbines HRSGs equipped with GE 7FA and 9FA GTs demand significantly more performance from their attemperator systems. This is due to the GE unit's unique exhaust gas temperature (EGT) characteristic. At minimum GT load EGT is about 510 °C (950 °F) unless the exhaust temperature matching (ETM) feature is engaged to lower it to 399 °C (750 °F). In addition, when the GT load is increased above minimum load EGT rapidly increases to 677 °C (1 250 °F) (called the isotherm) and remains there until GT load reaches about 60 %. This rapid increase in EGT to this high temperature early in the startup, when steam flow through the superheater is low, creates additional challenges for the attemperator's hardware and controls [4]. Table 5 shows the indicators for damaging attemperator performance, and operating practices known to cause damaging thermal transients unique to plants equipped with the GE 7FA/9FA GT.

Detailed assessments of the 3 GE 7FA/9FA plants have revealed:

High quality attemperator equipment, well-tuned cascaded anticipatory attemperator controls, use of ETM during all startups, holding of the GT at minimum load until more steam flow is available, and holding pressure steady while increasing GT load through the critical load range with EGT at the isotherm may be required to maintain stable, automatic attemperator control, avoid overspray conditions and avoid over-temperature excursions at the superheater/reheater outlet. Superheater arrangements with more than about 25 % of the total surface area positioned downstream of the attemperator (in the secondary superheater) have greater difficulty avoiding overspray conditions with GE units while at the same time preventing outlet steam temperature from exceeding design limits. As the proportion of total superheater surface located in the secondary superheater approaches 50 %, it becomes unlikely that both overspray and over-temperature can be avoided, even when all of the approaches listed above are utilized.

- 100 % of the GE 7FA/9FA plants assessed are equipped with simple steam outlet temperature feedback loop attemperator controls. This single shortcoming is a significant contributor to this group of plants' poor attemperator performance. Other GE 7FA/9FA plants, familiar to the authors but not included in these assessments, equipped with cascaded anticipatory control schemes are known to deliver acceptable attemperator performance.
- 67 % of the GE 7FA/9FA plants assessed manually manipulate attemperator control setpoint or manually

Thermal transient factors assessed unique to the GE 7FA/9FA gas turbine	Plant		
	A	D	I
Simple feedback loop used for attemperator control?	Yes	Yes	Yes
Manual control of attemperator spray valve?	Yes	No	No
Manual manipulation of outlet steam temperature setpoint?	Yes	No	Yes
Overspray conditions evident from DCS data in SH?	Yes	Yes	No
Overspray conditions evident from DCS data in RH?	Yes	No	No
Outlet steam over temperature conditions evident from DCS data in SH?	Yes	Yes	No
Outlet steam over temperature conditions evident from DCS data in RH?	Yes	Yes	No
Attemperator control instability evident from DCS data in SH?	No	Yes	Yes
Attemperator control instability evident from DCS data in RH?	No	No	Yes
Intermittent attemperator operation?	No	No	Yes
Use of ETM on shutdown?	No	No	No
Use of ETM during lag in unit startup?	No	Yes	No

Table 5:
Thermal transient factors unique to plants equipped with the GE 7FA/9FA GT for the HRSGs assessed.

Explanation of colors used in Table 5:

Red indicates that the unit is subject to undesirable thermal transients due to this factor.

Green indicates that the unit is not subject to undesirable thermal transients due to this factor.

position the spray water valve in an attempt to avoid excursions of steam outlet temperature above design limits. As previously noted, this is a dangerous practice and very likely to result in overspray conditions.

Are attemperators being operated effectively? The 11 detailed assessments have revealed:

- 22 % of the plants assessed experience overspray conditions during startup as indicated in DCS plots. Not surprisingly, all of these plants are equipped with the GE 7FA/9FA GT.
- 29 % of the plants assessed experience an excursion of the HP or RH steam outlet temperature above design limits during startup. Again, all are the GE 7FA/9FA equipped plants. Overspray conditions inflict significantly more thermal-mechanical fatigue damage in the superheaters and reheaters than the creep damage caused by brief periods of over-temperature operation. Operating procedures, controls and attemperator hardware should be optimized in an attempt to avoid both of these undesirable consequences if possible. However, when faced with the choice of overspray versus limited over-temperature operation during startup the priority should go to avoiding all overspray events.
- 44 % of the plants assessed experience attemperator control instability during startup. Two of the four are equipped with integral spray valve/nozzle assemblies, two of the four with simple controls (on the GE 7FA/9FA units), and two of the four with more sophisticated controls – possibly pointing out the need for additional focus on spray valve maintenance and control tuning. Figure 3 shows a DCS plot from one unit with significant control instability during a cold start.

For Economizers

There have been many failures at tube/header connections in HRSGs due to "inlet quench". During startup, prior to initiation of feedwater flow, the LP economizer feedwater-inlet section heats up close to around 138 °C (280 °F) [4]. In plants not equipped with thermal deaerators, or other means of warming the incoming feedwater above ambient temperature, the LP inlet header and tubes adjacent to the inlet nozzle undergo a large quench when the feed valve is first opened. Since the feed flow rate is often very low during the initial feed, the water only passes through the few tubes closest to the inlet nozzle – creating large tube-to-tube temperature differences. These very low flow rates (trickle feed) can also lead to flow instability and flow reversal in tubes near the gas path walls and the gap between side-by-side modules where end tubes pick up more heat from bypassing exhaust gas [4]. LP economizers that incorporate bent tubes in the inlet pass, and "cross flow" harps (baffles inside the headers force water to alternately flow up some tubes and down others as it progresses across the harp) generally suffer more from inlet quench than parallel flow harps with straight tubes [9]. LP economizer harps with inlet nozzles located on the upper header suffer more from flow instability and flow reversal than do bottom fed inlet harps due to down-flowing water having to overcome increasing buoyancy as it is heated.

The 11 detailed assessments have revealed:

- 55 % of the plants assessed have economizer drains arranged with a single small-bore inboard isolation valve for each harp and a common, larger downstream isolation valve. This arrangement has led to severe quenching in tubes located immediately above the drain con-

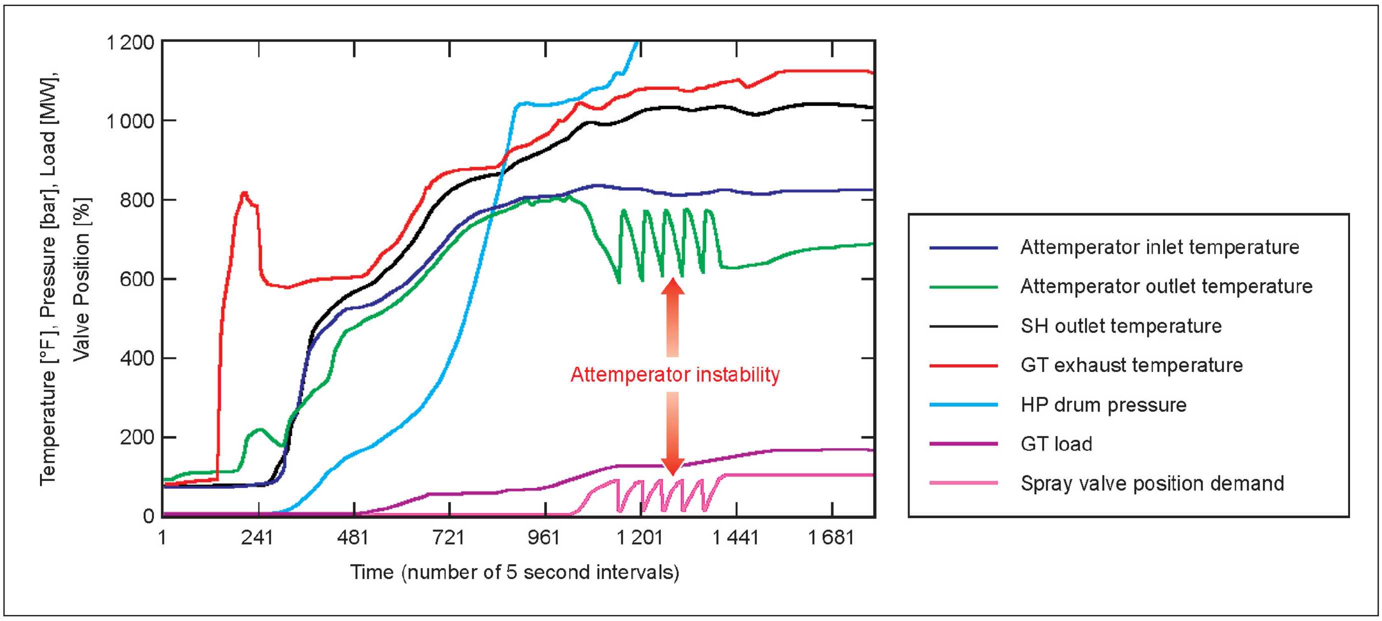

Figure 3:

This plant's attemperator system needs maintenance to reduce hunting. The unit is equipped with an integral spray valve / spray nozzle. This style of attemperator has a poor reputation for reliability in cycling service. It is likely that this hunting is due to the spray valve trim sticking.

Temperature in °C = (temperature in °F – 32) x 0.56

nection in the hotter harps due to water bypassing through the drainpipe when more than one of the small-bore valves develop seat leakage [9]. This risk is avoided by the installation of tandem small-bore isolation valves for each harp.

- 45 % of the plants assessed have cross flow economizer harps.
- 73 % of the plants assessed utilize a thermal deaerator or LP economizer recirculation system during startup to minimize inlet quench. LP economizer recirculation systems are generally designed for increasing feedwater inlet temperature above the acid dew point during low load operation and during oil firing. Some operators place these systems in service prior to startup to warm the water in a portion of the condensate piping – hopefully reducing the severity of inlet quench. The additional flow in the LP economizer created by recirculation may also reduce flow instability and flow reversal during trickle feed conditions. Plant-specific pipe routing and recirculation system flow capacity will determine how effective this practice is.

Are damaging economizer thermal transients being avoided?

- 27 % of the plants assessed report economizer tube/ header connection failures, or obviously stretched tubes due to quenching.

For Thick Wall Pressure Parts

The HP steam drum, the hottest and thickest HP superheater headers, and the hottest and thickest reheater headers require care during startup and shutdown to avoid initiating thermal-mechanical fatigue cracks due to overly aggressive heating and cooling rates [2].

- 55 % of the plants assessed have been given a maximum cool-down ramp rate for the critical superheater/ reheater headers by the OEM, or had the unit evaluated to determine the maximum safe ramp rate to be used during normal shutdown. 45 % are flying blind on this potentially expensive issue. All other things being equal, cooling a thick-walled pressure part too quickly causes significantly more thermal-mechanical fatigue damage than does heating it too fast [2].
- 27 % of the plants assessed have been given a maximum heat-up ramp rate for the critical superheater/ reheater headers by the OEM, or had the unit evaluated to determine the maximum safe ramp rate to be used during startup [2].
- 82 % of the plants assessed have been given a maximum heat-up ramp rate for the HP drum by the OEM, or had the unit evaluated to determine the maximum safe ramp rate to be used during startup.
- 45 % of the plants assessed use shutdown procedures that steam cool the superheaters and reheaters during normal shutdown [2]. Rapid unloading of the GT during normal unit shutdown leaves superheaters and reheaters near rated steam temperatures. After firing ceases and the GT is coasting down, or during a spin-cool, exhaust air temperature often falls below the prevailing saturation temperature inside superheater and reheater tubes. When this occurs, condensate forms in the tubes and falls into the lower headers. If the headers have been shutdown hot, they undergo a severe quench. Slower unloading of the GT (at a rate that results in decreasing EGT at the maximum cooling rate determined to be safe for the critical superheater/ reheater header) down to a load that produces an outlet steam temperature about 50 K (90 °F) above the prevailing HP saturation temperature, then holding at that load for a few minutes to let the header's through wall temperature gradient equalize before shutting down the GT, will avoid the damaging condensate quench after shutdown.
- None of the GE 7FA/9FA plants assessed use their ETM feature to control steam temperature ramp rate during normal shutdown. The exhaust temperature characteristics of these GTs result in very aggressive steam temperature ramp rates when shut down without using the ETM feature.
- 33 % of the GE 7FA/9FA plants assessed use their ETM feature to control exhaust temperature during startup of the "lag" HRSG in 2 x 1 plants. GE intended the ETM feature to be used to match steam temperature from the "lead" HRSG to the steam turbine's requirements during startup of a cold steam turbine. During such startups the lead HRSG is typically warmed up slowly and well within its HP drum and critical superheater/reheater header temperature ramp rates. Failure to "voluntarily" use ETM for startup of the lag HRSG typically exposes the critical superheater/ reheater headers to excessive heat-up ramp rates.

Are thick-walled pressure parts being protected from excessive thermal-mechanical fatigue damage?

- 45 % of the plants assessed routinely exceed prudent temperature ramp rates for their critical superheater/ reheater headers during both startup and shutdown. These plants are not likely to obtain design fatigue life from these expensive headers unless corrective actions are taken before too much damage is done.
- 27 % of the plants assessed routinely exceed prudent HP drum temperature ramp rates during startup. These plants are likely to find thermal-fatigue cracks in their HP drums before the HRSG reaches the end of its nominal design life if operating procedure changes are not implemented to slow startup temperature ramp rate.

CONCLUDING REMARKS

Eleven combined cycle/HSRG plants around the world have been assessed 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. The two most important aspects have been assessed: cycle chemistry and thermal transients. In the former, the assessments have addressed the key factors for flow-accelerated corrosion (FAC), under-deposit corrosion (UDC) and pitting. In the latter, the assessments have addressed thermal fatigue and creep fatigue. The assessments have provided a clear picture in each area of exactly where the weaknesses in the approaches are occurring, and it is not surprising that the current ranking order for HTF has remained rather static for the last 10 years. 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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