Abstract
Tetra Engineering has inspected over 50 large Reheat HRSG's in the past 4 years representing all major HRSG OEMs. The plants represent all NERC Regions and operating conditions. Almost all of these are relatively new units entering merchant service.

This paper will describe the issues and problems found in the areas of commissioning, supplemental firing, controls for temperature, startup and drains, fabrication and erection quality, corrosion control, critical piping issues and design issues. Case Studies and examples of the most prevalent problems will be discussed as well as industry wide conclusions. In general, HRSG reliability and availability has been quite good, but the demands on merchant units for commercial availability require the continued maintenance of high availability and low cost of maintenance.

Summary of Operating Experiences
Most large new combined cycle plants in the US were designed under the assumption that they would be baseloaded, or at least infrequently cycled. This basic assumption has proven to be far from actual operating modes for most new plants as indicated in Figure 1. Two-Shift cycling is differentiated from Seasonal Duty where plants are run essentially baseload, but only for a few months of the year. New plants include those that are commissioned but not running or which were inspected close to the time of commissioning.
Since combustion turbine ramp rates and startup procedures directly affect HRSG component temperature ramp rates, the push to rapid CT startups results in greater ramp rates in HRSG hot section components than was assumed in plant design analyses. Larger thermal stresses result with significant implications for fatigue life of affected components such as drums, thick section headers and tube-to-header welds.

Figure 1. Operating Modes of Inspected HRSGs

In additions, rapid thermal response results in more condensate accumulation during startups and a greater requirement for attemperation spray to control piping metal temperatures. These extreme conditions that are caused by cycling operations sometimes result in waterhammer in affected piping systems, thermal quenching of hot component surfaces and in some instance leakage or failure of the pressure boundary at tube-to-header welds, riser piping to drums, crossover (connecting) piping and drain
connections. Cold weather operations also provide a different challenge with the need to maintain temperature to prevent header failure from freezing conditions.

While new plants have operated in general significantly less than originally assumed, most have pursued an aggressive approach to assure that HRSG component integrity is verified by periodic inspections; usually during scheduled outages when the CT maintenance has been scheduled. A thorough inspection of a large HRSG (for example, behind a Frame 7FA, or 501F/G CT) with reheater components typically requires about 2 days for a crew of 2 people. These inspections are more detailed than statutory “boiler” inspections and typically include the following activities:

1. visual inspection of HRSG gas path components: tubes, headers and their supports, crossover piping, risers, drains, gas baffles, acoustic baffles and related structural components.
2. ultrasonic testing (UT) of wall thickness for selected (high risk) tube, header and riser components, thereby establishing the condition of HRSG components early in life. Drum baffle plates and in some instances cyclone separator “can” thickness are also measured at some plants.
3. visual inspection of accessible HRSG water-side components (for large combined cycle plants this is generally limited to drum surfaces and internals) including: primary and secondary steam separation devices, feedwater penetrations, instrument and blowdown penetrations and baffle plates and their mechanical restraints (bolting and/or welds).

In addition to these routine activities, plants with a history of HRSG component damage may also schedule dye penetrant (PT) inspection of areas susceptible to certain types of cracking, radiographic testing (RT) of tube-to-header welds when there is a suspicion of weld defects or sub-surface cracks. Thermography of HRSG casings is performed at some plants to identify hot spots, but is more commonly applied to older units which have accumulated more operating hours. Additional information on inspection planning is available in Reference 1.
Borescope inspections are relatively uncommon for large HRSG components due to a general lack of access to areas of interest; one exception is their use to perform inspections of attemperator spray liners. Attemperator sprays have been a significant problem for a variety of reasons including: poor engineering designs of spray line layout and control by HRSG OEMs, premature failure of some spray valve components in the field due to manufacturing/QC causes and a tendency to “overspray” in order to control metal temperatures in Reheater (and HP Superheater) outlet piping to below design values for units that are subject to heavy cycling.

Based on performing more than 50 of these inspections in the past few years (about 80% of all inspections have been for large reheat HRSGs), we have prepared some general observations about early operating experiences for relatively new HRSGs. These inspections include a wide variety of GT/HRSG combinations as indicated in Figure 2. While the HRSG is typically the major component that must be designed to be compatible with the specifications of the CT and the STG, there are some significant generalizations that have been observed with respect to early damage and operational problems.
Figure 2. Inspections by CT and HRSG Type

Figure 3 summarizes the relative frequency of the dominant damage mechanisms and related problems that we have encountered in performing these inspections. It does not include routine operating issues such as drum level control, etc. Not surprisingly, it is mechanisms which are most aggravated by cycling conditions (tube bowing, leaks and failures, gas baffle damage, desuperheater spray malfunctions, design issues and related controls problems and drain leaks and failures) that are most common.
Figure 3. Frequency of Common HRSG Damage Mechanisms
Some of these cycling related damage mechanisms (such as tube leaks and failures) have been significant enough to require (or cause) plant shutdown. Others have been detected during scheduled HRSG inspections. The approach taken in this paper is largely anecdotal; typical experiences will be discussed for each class of mechanisms.

While much of the focus of good operations and maintenance practice is oriented toward controlling corrosion of susceptible materials, primarily the carbon steel components that comprise most of the HRSG surface area, one immediate observation is that corrosion – at least so far – is not a significant problem at most plants. This is less a consequence of excellent water chemistry control than it is simply too early to detect small amounts of corrosion shortly after commissioning.

Flow accelerated corrosion (FAC) is a high-visibility issue which has been the cause of numerous fatalities at power plants over the years. FAC has not been detected at new reheat units although in general they have not operated long enough to experience significant wear, even for the highest risk locations. Experience from previous HRSG designs that have operated for longer periods (50,000 – 100,000 hrs) indicates that will likely change despite the best efforts of plant staffs to maintain water chemistry within targets.

Those units with some cold end corrosion problems generally have a combination of design issues, fuel gas quality issues and often frequent exposure of susceptible surfaces to high ambient humidity with long periods of layup.
Casing, Liner and Gas Baffle Damage

The most prevalent mechanism encountered in new units is damage to gas baffles. Due to the nature of their geometry and proximity to a variety of potential interferences, these structures are often subject to fatigue, distortion from thermal expansion and interference and to high vibrations, particularly in the hot sections of the HRSG. Casing and liner plate damage are also common with hot spots typically evident on the casing surface, around doors and anywhere there is insufficient insulation. Liner plates are generally damaged by thermal buckling, over constraint due to bolting/welding design and overheating in firing ducts. Some examples of these damage mechanisms follow.

Figure 4. Casing Hot Spot Below Transition Duct Floor
Figure 5. Failed Gas Baffle

Figure 6. Failed Casing Seal Weld around Reheat Connection to Lower Manifold
Figure 7. Failed Transition Duct Casing Liner

Figure 8. Buckled Liner Plates in Firing Duct
Figure 9. “Pinhole” in Fabric Expansion Joint
**Tube and Header Leaks and Failures**

The most significant damage that occurs in HRSGs is generally leaks and failures of pressure parts; specifically, tubes, headers and connecting piping. Tube failures are well known as dominant contributors to plant unreliability. While tube repairs are not lengthy procedures, they contribute substantially to the cost of cycling duty when they occur. Leaks and failures in larger components such as headers, major connecting piping and steam piping can require more lengthy outages with correspondingly greater costs. The most common tube damage mechanism is probably bowing which is attributable to a variety of sources including differential thermal stress, manufacturing variations in tube length, etc. From our inspections of new (pre-operational) units, we have observed that some slight tube bowing is sometimes present prior to operation. However, large displacements are not observed pre-service. Tube failures are less common, but have occurred at many large reheat HRSGs. The root causes of these failures varies and depends on many factors including: material type, exposure to high temperatures (gas temperature) during startup followed by quenching from condensate accumulation or excess attemperation spray, waterhammer and stress corrosion cracking. Flow accelerated corrosion (FAC) has not been observed in these relatively new units to date. Samples of these degradation types encountered in the field follows.

Condensate formation during startup is a well-known problem and plants experiencing repeated tube failures, extreme tube bowing and or related problems with attemperation spray equipment have sometimes installed temporary thermocouples to more accurately ascertain the temperature variations in reheater (and superheater) tubes. Some plants have also installed thermocouples to determine whether steam binding is occurring in HP Economizers that are poorly vented.

Diagnosis of tube failures is often difficult and generally requires the support of a trained metallurgist. General guidance on types of tube failure mechanisms and their identification is provided in Reference 2.
Figure 10. 70° Kink in Reheater Tube – Cycling Unit

Figure 11. RH Tubes Thermocouples Identify Condensate During Startup/Shutdown
Figure 12. Bowed RH Tubes below Cold Reheat Inlet following Waterhammer Event

Figure 13. Low Cycle Fatigue Failure of T91 Reheater Tube – Cycling Unit
Figure 14. Tensile Overload Failure of T91 Reheater Tube – Cycling Unit

Figure 15. Fatigue Failure of 304H Stainless Reheater Tube Stub – Cycling Unit
Figure 16. Tube Leak in T91 Reheater Tube Stub – Horizontal Section – Cycling Unit

Figure 17. Welding/Manufacturing Defect in Leaking HP Economizer Tube – Cycling Unit
Figure 18. Stress Corrosion Cracking Failure in LP Feedwater Tube – Cycling Unit

Figure 19. Crack in P22 Reheater Header Weld – Cycling Unit
Figure 20. Header Window Weld for Inaccessible Tube-to-Header Repair – Cycling Unit
Boiler and Steam Piping Damage

Problems with boiler and steam piping is often associated with the reheat piping; particularly where attemperator sprays have been designed with too short downstream straight pipe lengths (less than 10 pipe diameters). Incomplete atomization of attemperator sprays impacts downstream piping surfaces as liquid droplets where it can cause significant thermal stresses.

Waterhammer is another phenomenon that has occurred at a number of combined cycle plants. It is often attributed to a combination of problems related to spray valve control, drainage of condensate or abrupt valve actuation. Waterhammer is generally a destructive transient; casualties typically include adjacent piping supports with yielding of steam piping a common end result. Examples of typical boiler and steam piping damage from these mechanisms follow.

Figure 21. Leaking 16” Reheater Crossover Link Piping – Cycling Unit
Figure 22. Waterhammer Damage to Cold Reheat Piping and Supports – Cycling Unit

Figure 23. IP Feedwater to IP Drum Leak – Cycling Unit
Figure 24. DSH Spray Line Leak – Cycling Unit
Drain Leaks and Failures

Drain leaks and failures are another relatively common problem for newer units as indicated in Table 2. Drains are often cocked or otherwise bent during final construction when the pre-fabricated tube panel assemblies are connected in the field to the drain system. The result is often drain welds that are under considerable stress due to misalignment in casing holes and/or misalignment of drain tube stubs with the field drainwork. While relatively easy to repair, drain leaks have in some cases led to drum level instability requiring emergency plant shutdown. Inspection of accessible drain welds during scheduled HRSG Inspections is an effective way to reduce the likelihood of a drain failure during operation.

Figure 25. Bent HP SH Drain
Figure 26. Leaking Feedwater Preheater Drain

Figure 27. Weeping Crack in Drain Weld Below LP Economizer Crossunder Piping
Drum and Internals Damage

Damage to drum surfaces and internals includes problems with baffle weld designs, accumulation of tubercle deposits over pits in HP and LP drums and some small defects in drum shell surfaces. Because most of these new large units have been operating for only a few years there have been no incidents of severe corrosion of steam separation devices, development of fatigue cracks or other serious damage. However, many merchant plants spend extended periods in relatively long layup. Those employing dry layup with a nitrogen cap typically find relatively minor surface oxide. Some owners are using wet layup to accommodate the possibility for a more rapid startup; these units sometimes have greater incidence of tubercle formation with small pits underneath and adhered deposits on the drum shell. Sludge piles are often evident in LP Drums where iron transport is a problem due to inadequate control of oxygen levels. Cycling operation is not conducive to maintaining stable water chemistry and many operators are challenged to maintain their water chemistry within targets. Examples of these conditions follow.

Figure 28. Tubercles Covering Shallow Pits in HP Drum
Figure 29. Adhered Deposits at Waterline – IP Drum

Figure 30. Shallow Pit Below Tubercle in LP Drum
Figure 31. Sludge Pile in LP Drum

Figure 32. Cracked HP Drum Baffle Plate Weld
**Cold End Corrosion**

Cold end corrosion is enhanced in many merchant plants because they are operating for more time at part load than anticipated by design (and therefore component surface temperatures may be below the acid dewpoint temperature where acids will condense on tube surfaces and corrosion damage will occur). This problem is aggravated by greater than anticipated sulfur content in fuel gas in some locations. Older units have employed CO2 blasting to remove some of the deposits, but the effectiveness is limited if the affected harp (typically the LP Economizer or Feedwater Heater) has many tube rows.

Another damage mechanism that has caused tube failures in cold end components (see preceding discussion above) is stress corrosion cracking. This damage mechanism affects susceptible materials and can result in tube leaks or failures in a very short time (few years of operation). This mechanism may be accompanied by the accumulation of ID deposits which tends to protect and concentrate aggressive chemical species. Accumulation of ID deposits implies problems with feedwater water treatment and control.

Occasionally, bowed tubes are observed in the cold end of large units; sometimes these are near the feedwater inlets where the inlet water temperature may be significantly colder than adjacent tubes depending on the flow pattern in the harp design. This can lead to large thermal stresses between tubes.
Figure 33. Ammonium Bisulfite Accumulation on Feedwater Heater Final Row

Figure 34. Sticky Deposits (pH = 3) on LP Economizer Tubes
**Flow Distribution Device Damage and Failures**

Not all HRSGs have flow distribution devices. Their specification depends on a variety of factors related to the CT, geometry of the transition duct, general layout of the HRSG (# modules wide, height of unit), etc. When flow distribution devices are installed, there can be problems especially when they are upstream of the lead tube bank (which is where they need to be to re-distribute flow to higher tube elevations). In some cases a second flow distribution grid is installed upstream of duct burners to further modify the exhaust gas flow, although this is not common.

The most common design is the perforated plate design although other approaches have included large turning vanes and smaller sets of turning vanes. The most common problem is fatigue damage that is attributable to the high gas velocity and often inadequate structural support that is provided to hold the perforated plate in position. Often, the support structure behind the plate experiences extensive fatigue failures which weakens the plate and in turn fatigue begins to fail ligaments between the holes in the perforated plate. Examples of these problems follow.

![Fatigue Cracks in Ligaments and Stiffening Plates in Flow Distribution Grid](image-url)
Figure 36. Failed Flow Distribution Grid Vanes

Figure 37. Failed Component Embedded in Lead Tube Bank
**Duct Burner Issues**

Duct burners are used to increase steam production, either to compensate for reduced output due to ambient conditions or for additional (peaking) output. Duct burners can impact on the reliability of downstream tubes if flame impingement occurs. Typically, this can happen if the firing duct is not sufficiently long to accommodate the length of the burner flame. In this case the end of the flame is actually in the downstream tube panel. Local overheating of tubes has been attributed in some cases to excessive duct firing. Other problems with duct burners have involved the burner elements themselves either being improperly positioned or falling out of their supports during operation so they were no longer supported at both walls. Some examples of these problems follow.

![Figure 38. Duct Burner Flame Impingement on Downstream Tubes](image-url)
References