BOILER WATER MANAGEMENT GUIDELINES FOR BLACK LIQUOR RECOVERY BOILERS

THE BLACK LIQUOR RECOVERY BOILER ADVISORY COMMITTEE
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Recovery Boiler Water Management Guidelines
(black italicized text = to be developed, green text = completed, blue text = in progress 2015)

1. Clarification/Filtration Systems

2. Makeup Water Systems

3. Feedwater & RB Water Systems

3.1 Deaerator Systems

3.2 Feedwater Pump & Piping Systems

3.2.1 Design & Operational Considerations
3.2.2 Chemical Treatment & Control Considerations
3.2.3 Key Maintenance Practices & Protocols
3.2.4 SOPs
3.2.5 ESOPs
3.2.6 Monitoring
3.2.7 Inspection/Documentation

3.3 Feedwater Steam Attemperation Systems

3.3.1 Design & Operational Considerations
3.3.2 Chemical Treatment & Control Considerations
3.3.3 Key Maintenance Practices & Protocols
3.3.4 SOPs
3.3.5 ESOPs
3.3.6 Monitoring
3.3.7 Inspection/Documentation

3.4 Blowdown Heat Recovery Systems

3.4.1 Design & Operational Considerations
3.4.2 Chemical Treatment & Control Considerations
3.4.3 Key Maintenance Practices & Protocols
3.4.4 SOPs
3.4.5 ESOPs
3.4.6 Monitoring
3.4.7 Inspection/Documentation
4. Recovery Boiler

4.1 Economizer Systems

4.1.1 Design & Operational Considerations
4.1.2 Chemical Treatment & Control Considerations
4.1.3 Key Maintenance Practices & Protocols
4.1.4 SOPs
4.1.5 ESOPs
4.1.6 Monitoring
4.1.7 Inspection/Documentation

4.2 Drum, Tube & Header Circuitry

4.2.1 Design & Operational Considerations
4.2.2 Chemical Treatment & Control Considerations
4.2.3 Key Maintenance Practices & Protocols
4.2.4 SOPs
4.2.5 ESOPs
4.2.6 Monitoring
4.2.7 Inspection/Documentation

4.3 Chemical Cleaning

4.3.1 Introduction & Definitions
4.3.2 Cleaning Determination Protocol
4.3.3 Chemical Cleaning
4.3.4 Key Maintenance Practices & Protocols

5. Condensate Systems

5.1.1 Design & Operational Considerations
5.1.2 Chemical Treatment & Control Considerations
5.1.3 Key Maintenance Practices & Protocols
5.1.4 SOPs
5.1.5 ESOPs
5.1.6 Monitoring
5.1.7 Inspection/Documentation

6. Sampling & Testing Protocols
Changes

3.2.1 Changed system sketch from “High Purity Water – Ultra Low Conductivity – Ultra Low Dissolved Oxygen” to “Feedwater Quality Water” to illustrate feedwater pump seal water. Note that the sketch needs this change highlighted – I don’t have access to the drawing.

Clarified ORP in the last bullet item, spelling it out as “Oxidation – reduction potential (ORP)”.

3.2.6.2 Changed feedwater pH instrumentation from “advisable” to “required”. WTSC checklist is also updated to reflect this change.

3.2.7.2 Added “and recommended” to the statement “It is best practice and recommended to reinject cooled feedwater were packing gland systems are utilized”.

3.3.1 Added “ESP shutoff valve” to the text that accompanies the illustration of “Attemperation with Feedwater”.

3.3.6.3 Changed wording from “Monitoring cation conductivity will require the installation of a sample cooler and small cation exchange column upstream of the conductivity probe.” to “Monitoring cation conductivity requires the installation of a sample cooler and small cation exchange column upstream of the conductivity probe.”

4.1.1 Added the statement to the basic system component design “Heat exchangers (flue gas/feedwater and air/feedwater are optional and not illustrated)”.

4.1.6.2 Removed the sentence “High pressure sample coolers are required on economizer sampling systems.”

4.2 New section added to the document covering the boiler water circuit.
### 3.2 Feedwater Pump & Piping Systems

#### 3.2.1 Design & Operational Considerations

**System Overview**

Feedwater pump systems are designed to provide:

- Stable drum water level control under all firing conditions
- A spare pump in the event of main pump failure.

**Basic System Flow Path**

The following illustration represents basic deaerator/feedwater circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for this system are from the deaerator storage tank outlet penetration(s) to the inlet of the economizer.
Feedwater Pump and Piping Systems

Basic System Component Design

A basic feedwater pump system is comprised of:

- Drop legs or piping runs from one or more deaerator storage tank to a feedwater pump inlet header
- A feedwater pump suction header (suction side of the pump(s))
- Pump suction strainers
- A feedwater discharge header (discharge side of the pump(s))
- Full capacity pump(s) as well as a full capacity backup pump(s)
- Feedwater pump(s) can be steam- or electric-driven. Preferably the main operating pump would be steam-driven with an electric backup on standby. Where only electric-driven pumps are employed, there should be a secondary source of electrical power supply to the pumps
- Minimum flow recirculation lines (typically routed back to the deaerator)
- A pump shaft seal system (either mechanical seals or packing glands with/without seal water)
- Regulating control valve system, an isolation valve, a non-return valve, a drain valve, and a rapid drain valve
- A high pressure feedwater heat exchanger may be employed for temperature control (not illustrated)
- Chemical injection quills of proper design and materials of construction
- A continuous oxygen analyzer (with trend capabilities) is recommended. The sampling system should have sample extraction capabilities on both the suction and discharge side of the feedwater pump(s)
- Conductivity element with alarm capabilities (located in the droplet below the deaerator storage tank or discharge side of the feedwater pumps. Discharge side is best practice.)
- Cation conductivity where feedwater is utilized for attemperation (recommended)
- pH element with alarm capabilities (recommended)
- Oxidation reduction potential (ORP) measurement (optional).

Basic System Control Technology

The feedwater flow regulating valve is controlled by a steam drum level control system.

The rapid drain valve and feedwater flow stop valve are controlled by the rapid drain system.

3.2.2 Chemical Treatment & Control Considerations

Water/Steam Purity Impact Assessment

Impurities that enter through the feedwater circuit can result in potential damage to the boiler system circuitry. The source of these impurities can be the deaeration system or the feedwater pump(s). Contamination levels, if significant, can alter water chemistry and result in corrosion of the circuit metallurgy and/or deposit formation.
# Feedwater Pump and Piping Systems

## Key Chemical Control Variables

American Society of Mechanical Engineers (ASME) guidelines should be consulted for a full discussion of chemical control variables, including dissolved oxygen, pH, conductivity, iron, copper, and hardness (ASME guidelines are contained in the Appendix section).

Mills shall maintain emergency standard operating procedures (ESOPs) for reacting to out-of-range feedwater parameters. At a minimum, these shall include oxygen, iron, pH, hardness, silica, and conductivity.

When contamination is suspected, operators should always validate their test results and, once validated, follow the ESOPs that are in place to troubleshoot the problem. The validation step is to ensure that the sample conditioning station or sample preparations are not the source of the apparent contamination.

## 3.2.3 Key Maintenance Practices & Protocols

### System Reliability Impact Assessment

Feedwater pumps and pumping systems can produce/experience high flows and can also be a source of contaminant ingress (dissolved solids, oxygen, iron, etc.). Erosion/corrosion of the downstream piping system is the primary concern.

### Inspection Techniques

Inspect pump seal water systems and review seal water quality for adequacy (seal water quality should be equivalent to that of the feedwater).

Identify high risk areas in the feedwater piping system (such as bends, elbows, and any injection quill locations) and employ NDE methods to inspect for flow accelerated corrosion.

Inspect and routinely calibrate the system O₂ analyzer and visually inspect all associated sample piping and valves. Monitor or periodically inspect for the presence of any sample flow restrictions and/or diversion of sample steams that may impact the accuracy of test results.

If raw or mill water is used on sample cooler/heat exchanger, the heat exchanger should be periodically inspected and cleaned.

### Inspection Frequency

Strainers - There are instances when strainers foul with materials like fiber and resin. The source of these materials can be water system-related and may have impacted other water support systems and sample monitoring devices. It is recommended that feedwater pump strainers be inspected in accordance with planned feedwater pump maintenance schedules. In addition, it is advisable to monitor pressure drop across the strainers to ensure that the strainers are not accumulating materials that may restrict feedwater flow.
Feedwater Pump and Piping Systems

Seal Water Systems - Inspect and review water quality as mill experience dictates.

Feedwater Piping Systems - The mill should develop a protocol that delineates the inspection frequency for flow-assisted corrosion in high risk areas (typically every 3 - 5 years, but can also use condition based methodology).

O2 Analyzers - Units should be inspected and calibrated in accordance with the OEM guidelines. Associated sample piping systems, valves, and sample coolers should be inspected as mill experience dictates.

3.2.4 SOPs

3.2.4.1 - SOP - Feedwater Iron Levels - An SOP shall be in place that states the ASME guidelines for iron levels in the boiler feedwater. The SOP should include method of testing, by whom, and how often.

(Note: An operator log sheet or data entry system that specifies all of the above may be an acceptable substitute.)

Oxygen intrusion and process-related iron ingress can both contribute to high iron levels in the feedwater. Low pH and misapplied water treatment chemicals can also elevate iron levels. There are a variety of tests that measure iron in its different oxidation states. The most common method employed is a Millipore™ iron filtration test. Iron colormetric tests are also utilized.

Iron tests can be run on samples taken from various points within the feedwater circuitry. The type of iron test, sample extraction points, and sampling protocols will be a function of system design, chemistry employed, and conditions encountered. The objective of the testing is to identify particulate iron and/or iron corrosion by-products that may potentially contaminate the feedwater.

The deaeration system and the feedwater piping between the deaerator outlet flange and the economizer inlet flange are one source of iron contamination. The condensate system is the other major source of iron.

For additional information regarding iron monitoring, testing, and control (downstream of the economizer inlet) refer to the Economizer and Drum, Tube & Header Circuitry sections of these BLRBAC Water Treatment Guidelines.

Consult your water treatment subject matter expert to determine the best testing protocols to meet your mill's specific needs.

3.2.5 ESOPs

3.2.5.1 - ESOP - Feedwater Dissolved Oxygen Ingress - An ESOP shall be in place to address oxygen contamination of feedwater. Possible sources for oxygen in the feedwater include the deaerator and feedwater pump seals.
3.2.5.2 - ESOP - Feedwater Low/High pH - An ESOP shall be in place to address both high and low feedwater pH conditions. The ESOPs should address the following for both low and high pH conditions:

- Test validation and verification prerequisites for either condition (pH meter validation, etc.)
- Differentiate between a parameter step change and a gradual change in the trend
- Decision tree to specify at what pH level fire should be removed from the boiler.

3.2.5.3 - ESOP - Feedwater High Conductivity - An ESOP shall be in place to address high feedwater conductivity.

BLRBAC requires that recovery boiler feedwater systems have continuous conductivity monitoring and alarm capabilities. There should be a high alarm conductivity setpoint with the appropriate action steps to be taken by the operators in the event of an alarm condition. The instrument department should confirm that the alarm setpoint is as prescribed by the water treatment subject matter expert. The ESOP should address the following for high conductivity conditions:

- Decision tree to specify at what conductivity level fire should be removed from the boiler.

(For specific information on cation conductivity for monitoring feedwater attemperating systems refer to the Feedwater Steam Attemperation Systems section of the BLRBAC Water Treatment Guidelines.)

3.2.5.4 - ESOP - Feedwater Hardness Ingress - An ESOP shall be in place that addresses action steps to be taken to address hardness levels above ASME guidelines for boiler feedwater. The ESOP should address the following for high hardness conditions:

- Hardness test validation and verification
- Differentiation between a hardness level step change and a gradual change in the trend
- Alternative test method (colormetric/titrimetric).

Most common hardness sources include:

- Feedwater pump seal water
- Process water hardness-related ingress that may occur in systems upstream of the feed pumps
- Sample cooler ingress.

Consult your water treatment subject matter experts to determine the best ways to deal with hardness ingress issues.
## 3.2.6 Monitoring

### 3.2.6.1 Monitoring - Feedwater Conductivity w/Alarm Setpoint

Recovery boiler feedwater systems with continuous conductivity monitoring and alarm capabilities are a BLRBAC requirement. Alarm conductivity setpoint should be validated with the appropriate action steps to be taken by the operators (refer to feedwater hardness ESOP) when the system is in alarm mode or conductivity levels in the feedwater suddenly trend upwards.

### 3.2.6.2 Monitoring - Feedwater pH

To monitor and identify feedwater ingress contaminants that may be slightly conductive yet acidic in nature (organic acids) or to provide redundant indication when experiencing alkaline ingress (black liquor, etc.), it is **required** to have pH measurement as a feedwater monitoring tool.

Consideration should be given to the influence of amines upon the pH monitoring and alarm and control setpoints employed. The primary focus should be a discernable and sustainable step change in the feedwater pH reading under normal operating and chemical material balance conditions.

### 3.2.6.3 Monitoring - Feedwater Oxygen Testing & Sampling

There should be a properly designed and constructed high pressure sample cooling system in place to accommodate testing for dissolved oxygen on both the suction and discharge sides of a feedwater pumping system. The sample extraction points for dissolved oxygen testing are as follows:

- Feedwater pump suction
- Feedwater pump discharge (ahead of the economizer inlet (recommended)).

To optimize test results, the sample conditioning requirements, sample line location, length of sample line run, and sample flow should be taken into consideration when installing a dissolved oxygen sampling system.

The location of the chemical feed point relative to the sample extraction point can influence test results.

Constant feedwater sample temperature and flow rate should be as per the equipment manufacturer's specifications. For more information on installation points, sample flow requirements and temperature limitations, contact/refer to one or more of the following:

- Equipment manufacturing specifications (OEM)
- Your water treatment subject matter experts
- TAPPI TIP #0416-03 "Water quality and monitoring requirements for paper mill boilers operating on high purity feedwater" and 0416-14 "Water quality guidelines and monitoring requirements for paper mill boilers operating with softened makeup water."
### 3.2.7 Inspection/Documentation

<table>
<thead>
<tr>
<th>Section</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>3.2.7.1</strong></td>
<td><strong>Feedwater Flow-Accelerated Corrosion</strong> - The feedwater piping should be designed to reduce the effect of flow-accelerated corrosion. Flow-accelerated corrosion can be influenced by any changes in operation such as an increase in feedwater flow rate, change in pH, dramatic change in dissolved oxygen levels, or a change in feedwater system chemistry. There are nondestructive test protocols for feedwater piping that should be conducted periodically to check for flow-accelerated corrosion.</td>
</tr>
<tr>
<td><strong>3.2.7.2</strong></td>
<td><strong>Feedwater Pump Mechanical Seals or Packing Glands</strong> - Leakage in and around shaft seal systems can impact feedwater quality. It is a best practice and recommended to reinject cooled feedwater where packing gland systems are utilized. It is a best practice and recommended to utilize high purity water for mechanical seal cooling. The feedwater pump seal water system documentation shall delineate standard operational and maintenance practices and established inspection frequencies.</td>
</tr>
</tbody>
</table>
| **3.2.7.3** | **Feedwater Chemical Delivery Systems** - A chemical feed injection quill is required when introducing a chemical into feedwater piping. It is recommended that the point of feed survey (line diagram) be updated annually or following a change in chemistry or feed point. Chemical injection quills should be of proper design and materials of construction. For more information on installation points, sample flow requirements and temperature limitations, contact/refer to one or more of the following:  
- Equipment manufacturing specifications (OEM)  
- Your water treatment subject matter experts  
- TAPPI TIP 0416-03 and 0416-14. |
| **3.2.7.4** | **Copper Metallurgy** - Identify the alloys deployed in the recovery boiler water system heat exchangers to determine if there are any potential sources of copper. Common sources of copper include:  
- Copper alloy heat exchangers  
- Copper alloy steam coil air heaters  
- Copper alloy sweetwater condensers  
- Heating systems. Sampling techniques for copper ingress should be reviewed with your subject matter expert. If copper ingress is suspected, then samples extracted from the pertinent streams should be sent out to the lab for high purity analysis. An action plan should be developed; predicated upon the lab findings. Consult your water treatment subject matter experts to determine the best ways to deal with copper issues. |
### 3.2.7.5 - Inspection/Documentation - Feedwater Oxygen Analyzers

Facilities shall have a routine instrumentation checklist in place that details the maintenance, calibration practices, and inspection of O\(_2\) analyzers and their associated sample piping, valves, and sample coolers.
# Feedwater Steam Attemperation Systems

## 3.3 Feedwater Steam Attemperation Systems

### 3.3.1 Design & Operational Considerations

<table>
<thead>
<tr>
<th>System Overview</th>
</tr>
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<tbody>
<tr>
<td>Attemperation, sometimes referred to as desuperheating, is the process whereby the boiler superheated steam is cooled with water to obtain a constant steam temperature. Since the water utilized in the attemperation process is introduced upstream of a steam turbine, and/or in many cases introduced within the superheater circuitry, it must be extracted from a reliable source that is relatively pure (trace levels of dissolved and/or suspended solids).</td>
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<tr>
<td>There are several sources of high purity water within the recovery boiler water support system that can be utilized for attemperation water:</td>
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<tr>
<td>- <strong>Sweetwater condenser</strong> (condensed steam from a dedicated heat exchanger) is the water source of highest purity. If properly designed and integrated into the feedwater system, a sweetwater condenser is also the most reliably consistent source of attemperation water.</td>
</tr>
<tr>
<td>- <strong>Recovery boiler feedwater</strong> is another attemperation water source that is commonly utilized. In some applications feedwater is a backup supply to a sweetwater condenser. The level of impurities in this water source can vary as water quality from the various support systems (ion exchange systems, condensate systems, etc.) fluctuates. Water treatment chemistry upstream of the attemperation water extraction point can also influence water quality.</td>
</tr>
<tr>
<td>- <strong>Turbine condensate</strong> is the third most common source of attemperator supply water and, in some applications, is a backup supply to the two aforementioned water supply systems. The level of impurities in this water source can vary as a function of the purity of the steam supply to the turbine condenser, oxygen, and other contaminants that may be present in the condensed steam. Consideration must be given to condenser leaks that will impact condensed steam water quality.</td>
</tr>
<tr>
<td>- <strong>Polished condensate</strong> can be an attemperation water source; however, reliability and consistency factors tend to place this water source in the emergency backup category. If polished condensate is considered for backup purposes, the resin bed must be regenerated with an amine.</td>
</tr>
<tr>
<td>- <strong>Demineralized water</strong>, in very limited applications, is utilized as either a lead or backup attemperator water supply source. Since, in all likelihood, this water is not deaerated, its use as an attemperator supply water source is <strong>strongly discouraged</strong> due to its oxygen content. A detailed corrosion study of all downstream circuitry and steam/water system components is recommended.</td>
</tr>
<tr>
<td>In this BLRBAC guideline, the focus will be upon the sweetwater condenser and boiler feedwater attemperating water systems. Other water sources will be considered as either special applications and/or backup attemperator water supply sources.</td>
</tr>
</tbody>
</table>
Feedwater Steam Attemperation Systems

Basic System Flow Path

The following illustrations represent conventional feedwater steam attemperation system circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for this system are from the boiler feedwater system to the superheater outlet.
## Feedwater Steam Attemperation Systems

<table>
<thead>
<tr>
<th>Basic System Component Design</th>
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<tbody>
<tr>
<td>Attemperation with feedwater (upper illustration).</td>
</tr>
<tr>
<td>• Attemperator sleeve</td>
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<tr>
<td>• Control valve</td>
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<tr>
<td>• ESP shutoff valve</td>
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<tr>
<td>• Cation conductivity measurement.</td>
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<tr>
<td>Attemperation with a sweetwater condenser (lower illustration).</td>
</tr>
<tr>
<td>• Attemperator sleeve</td>
</tr>
<tr>
<td>• Sweetwater condenser (metallurgical considerations)</td>
</tr>
<tr>
<td>• Control valve</td>
</tr>
<tr>
<td>• Sweetwater condenser sample line (for grab sample)</td>
</tr>
<tr>
<td>• Steam temperature indication before and after attemperation.</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Basic System Control Technology</th>
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</thead>
<tbody>
<tr>
<td>The attemperator water flow is controlled to sustain the desired superheated steam outlet temperature.</td>
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</tbody>
</table>

### 3.3.2 Chemical Treatment & Control Considerations

<table>
<thead>
<tr>
<th>Water/Steam Purity Impact Assessment</th>
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<tbody>
<tr>
<td>Since the water utilized in the attemperation process is introduced upstream of a steam turbine and/or in many cases introduced within the superheater circuitry, it must be extracted from a reliable source that is relatively pure (trace levels of dissolved and/or suspended solids).</td>
</tr>
</tbody>
</table>

The impurities present in that attemperating water source can impact the reliability of recovery boiler superheater circuitry (if interstage desuperheating is employed) and other key support system operating components (turbines) located downstream of the attemperation water injection point.

**Note:** Other related water support systems can become contaminated and alter the purity of the attemperation water supply source. Where attemperation systems other than a sweetwater steam condenser are utilized, the water quality of those water support systems should be monitored.

Attemperation water purity can vary on either a continuous or intermittent basis. Therefore sampling, monitoring, and operator notification protocols should be in place that focus upon identifying step changes or intermittent variations in the attemperation water supply under differing makeup water demands and return condensate conditions.
# Feedwater Steam Attemperation Systems

## Key Chemical Control Variables

The key control variable in monitoring attemperator water purity is conductivity. Other variables such as pH and sodium also provide meaningful information.

An increase in conductivity in the attemperator water supply can be caused by an increase in cation/anion loading (non-volatile contaminants) and/or an increase in amine/ammonia loading (volatiles typically associated with water treatment). The non-volatile contaminants can deposit in steam/water components located downstream of the attemperation introduction point.

There are two commonly employed methods of monitoring/measuring conductivity:

- **Specific Conductance** - Measures how a water source containing both volatile and non-volatile water contaminants (cations, anions, amines, and ammonia) conducts an electrical current.

- **Cation Conductivity** - Sensitizes the specific conductance measurement and focuses upon only the anion water components in the water source intentionally eliminating amines and ammonia.

Cation conductivity is recommended because the presence of amines and ammonia in the attemperation water source make it difficult to tell the difference between volatile and non-volatile contributors to the conductivity of an attemperating water source. Non-volatile solids can deposit in superheaters and turbines.

To test for the non-volatile components, a cooled-continuous flowing attemperator water sample stream is processed through a small cation exchange column located upstream of a conductivity probe yielding a cation conductivity measurement. The resultant cation conductivity measurement provides a more accurate measurement of the cation/anion loading within the attemperator water supply.

Discernable and sustainable incremental step changes (short-term) in chemical control variables monitored on a continuous or intermittent basis would require an investigation as to probable cause. In such cases, the water treatment subject matter experts should be contacted immediately.

## 3.3.3 Key Maintenance Practices & Protocols

### System Reliability Impact Assessment

The consequences of poor quality water or improper attemperator water dispersion could include:

- Deposit formation within the attemperator (flow restriction)
- Deposition on downstream components (superheater tubes and turbine blades)
- Thermal cycling of components
- Flooding of superheater pendants
- General mechanical integrity issues
- Superheater tube failure.
# Feedwater Steam Attemperation Systems

<table>
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<tr>
<th>Inspection Techniques</th>
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</table>

Attemperator piping should be equipped with a properly designed inspection port so the attemperator can be visually inspected with a boroscope. The visual inspection should include, but not necessarily be limited to:

- Spray nozzle assembly (diaphragm, nozzle welds, backing plate, spray head)
- Liner (if applicable)
- Attemperator body (look for erosion or cracks).

If a sweetwater condenser is utilized, it should be inspected for general structural integrity. Metallurgy of the heat exchanger tubes should be verified. If a condensed steam sample line exists, it should be free of obstructions. Temperature control valves should be monitored and maintained to prevent excessive leak-by.

<table>
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<tr>
<th>Inspection Frequency</th>
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</table>

The frequency of inspection for the attemperator piping or the sweetwater condenser system is mill location specific, but typically coordinated/aligned with turbine outages.

### 3.3.4 SOPs

N/A

### 3.3.5 ESOPs

#### 3.3.5.1 - ESOP - Attemperator Water Quality -

An ESOP shall be in place that addresses attemperation water quality. This ESOP should provide guidance if the water quality is determined to be:

- Outside the prescribed operating boundaries for the parameters being monitored
- Undergoing a discernable and sustainable parameter step change

Your water treatment subject matter expert should be consulted if the attemperator water source changes.

Samples of any suspect attemperation water source should be extracted and saved for future examination during any period of time when one or more of the aforementioned conditions are encountered.

The ESOP should also address what action should be taken if a sustained or intermittent change in the purity of steam is experienced. It should specifically focus upon contamination of attemperation water sources (turbine condensate, sweetwater condenser condensate, etc.).
### 3.3.6 Monitoring

**3.3.6.1 - Monitoring - Sweetwater Condenser Water Sampling** - To have the capability to test the condensed steam for contamination within the sweetwater condenser shell section (i.e., boiler water carryover, feedwater inleakage, metals), there should be a sample extraction point at the attemperation water outlet.

**3.3.6.2 - Monitoring - Attemperator Water Conductivity** - Attemperator water supply sources that exceed 12 µS/cm conductivity should be scrutinized for suitability of use by your water treatment subject matter experts.

**3.3.6.3 - Monitoring - Attemperator Feedwater Cation Conductivity** - Where feedwater is utilized as the primary source of steam attemperation, continuous monitoring of cation conductivity of the feedwater is recommended.

Monitoring cation conductivity will require the installation of a sample cooler and small cation exchange column upstream of the conductivity probe. In systems where the conductivity probe is located directly in the feedwater line, the probe will need to be relocated and made an integral part of the sampling system.

There should be alarm and conductivity setpoints with the appropriate action steps to be taken when the system is outside specified limits.

**3.3.6.4 - Monitoring - Sweetwater Condenser Water Quality** - If the water quality is not monitored on a continuous basis it is advisable to have the water treatment subject matter expert establish a test protocol.

### 3.3.7 Inspection/Documentation

**3.3.7.1 - Inspection/Documentation - Attemperator Metallurgical Considerations** - It is recommended that the metallurgy of the sweetwater condenser be reviewed for suitability.

**3.3.7.2 - Inspection/Documentation - Annual Review of Attemperator Drawings (P&IDs, Flow Diagrams)** - Maintain up-to-date drawings of the attemperation water system. Include all backup water sources, sample locations, and chemical feed points (if applicable). An annual review of the system drawings and the backup system utilization strategy is recommended.

**3.3.7.3 - Inspection/Documentation - Prohibited Chemistry - Non-Volatile Chemicals** - The addition of non-volatile chemicals upstream of any attemperation water source is strictly prohibited. Dissolved solids (non-volatiles) present in the water can, at elevated temperatures, deposit on component parts and circuits associated with superheat steam system.
### Feedwater Steam Attemperation Systems

<table>
<thead>
<tr>
<th>Section</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>3.3.7.4</strong> - <em>Inspection/Documentation - Change in Attemperation Water Source</em></td>
<td>A management of change document should be in place that addresses what action should be taken if there is a change in attemperating water source. Procedures should include action steps to confirm that the attemperating water is suitable for use as defined by your water treatment subject matter experts.</td>
</tr>
</tbody>
</table>
| **3.3.7.5** - *Inspection/Documentation - Attemperator Inspection Guideline* | Facilities should develop and maintain their own formalized written maintenance protocol governing the inspection of attemperator system components. Attemperator piping should be equipped with a properly designed inspection port so the attemperator can be visually inspected with a boroscope. The visual inspection should include, but not necessarily be limited to:  
- Spray nozzle assembly (diaphragm, nozzle welds, backing plate, spray head)  
- Liner (if applicable)  
- Attemperator body (look for erosion or cracks).  
If a sweetwater condenser is utilized, it should be inspected for general structural integrity. If a condensed steam sample line exists, it should be free of obstructions. Temperature control valves should be monitored and maintained to prevent excessive leak-by. |
| **3.3.7.6** - *Inspection/Documentation - Attemperator Checklist* | As stated earlier, the quantity and the purity of the attemperation supply water can impact downstream system components. Poor steam temperature control can exacerbate other problems and further complicate any potential deposition-related concerns. The temperature control valve position and superheater steam outlet steam temperature conditions should be routinely reviewed and incorporated into a checklist. |
# Blowdown Heat Recovery Systems

## 3.4 Blowdown Heat Recovery Systems

### 3.4.1 Design & Operational Considerations

<table>
<thead>
<tr>
<th>System Overview</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blowdown heat recovery systems are designed to recover some of the latent heat energy within the boiler blowdown water through the process of flashing steam from a tank at a lower operating pressure.</td>
</tr>
<tr>
<td>The continuous blowdown system controls the concentration of dissolved and suspended solids in the recovery boiler water, whereby a portion of the most concentrated boiler water is continuously extracted from the boiler steam drum. A small percentage of boiler water (typically 1% - 3% of the feedwater flow) exits the steam drum via a small diameter blowdown line. It should be noted that the location of the blowdown line within the steam drum and the orientation, sizing, and spacing of the orifices can impact how effectively the solids are extracted from the boiler water. The flow of boiler blowdown water can be controlled manually or automatically. Where flow meters are to be employed, the location of a continuous blowdown flow meter requires careful consideration with respect to static head and its positioning relative to the blowdown flow control valve.</td>
</tr>
<tr>
<td>Boiler water from the internal blowdown line is routed to a singular blowdown collection tank (flash tank) or, in some applications, a series of cascading pressure blowdown collection tanks.</td>
</tr>
<tr>
<td>In some heat recovery systems, a heat exchanger is also utilized to recover some of the sensible heat energy in the residual blowdown water as it is discharged from the flash tank. In some blowdown heat recovery systems, a properly engineered heat exchanger can take the place of the flash tank.</td>
</tr>
<tr>
<td>A malfunctioning blowdown heat recovery system can become a source of steam contamination to the recovery boiler water system.</td>
</tr>
<tr>
<td>If the flashed steam becomes contaminated with boiler water, recovery boiler deaeration systems and other low pressure steam users can be impacted; ultimately affecting the quality of the boiler feedwater.</td>
</tr>
</tbody>
</table>
Blowdown Heat Recovery Systems

Basic System Flow Path

The following illustration represents basic continuous blowdown system circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for the system are from the boiler steam drum continuous blowdown line to the two locations where the blowdown water flashes and the remaining liquid discharges.
## Blowdown Heat Recovery Systems

### Basic System Component Design

A conventional blowdown heat recovery system is comprised of:

- A blowdown line (typically 1” - 1½” diameter) located inside the steam drum
- An external blowdown line (typically 1” - 1½” diameter)
  - Two external manual isolation valves (typically located in close proximity to the steam drum)
  - Manual blowdown valve (with valve position indications)
  - Flow meter (optional)
  - Automatic flow control system (optional)
- A flash tank (with or without internal baffles)
  - Blowdown line penetration(s) into the flash tank steam space
  - Water level sight glass
  - A manual or automatic level control system
  - Steam piping for tying into a low pressure steam distribution system
  - Safety valve
- Additional flash tanks (in series - optional)
- A heat exchanger (typical but optional) supplied with cool RO and/or ion exchanged processed water where a transfer of heat from the boiler blowdown water to the processed water takes place. **Note:** In most continuous blowdown heat exchanger applications that processed water is utilized as recovery boiler makeup water.

### Basic System Control Technology

A basic blowdown heat recovery system should have a level control system to maintain boiler blowdown water level within the flash tank.

### 3.4.2 Chemical Treatment & Control Considerations

#### Water/Steam Purity Impact Assessment

Boiler water impurities in the flashed steam can distribute throughout the mill’s steam distribution system, and can eventually contaminate the low pressure steam supply.

Recovery boiler deaeration systems utilize low pressure steam. Other end users utilize low pressure steam that, when condensed, can return as condensate to the recovery boiler feedwater system.

Flash steam contamination in a blowdown heat recovery system can cause an undesirable increase in recovery boiler feedwater conductivity which, in turn, will result in an elevation of solids levels within the recovery boiler circuitry and, where applicable, in feedwater superheater attemperation systems.

The level of contamination, if significant, has the potential to alter the recovery boiler system chemistry, impact steam purity, and contribute to the formation of waterside deposits and/or contribute to corrosion mechanisms.
### Blowdown Heat Recovery Systems

**Note:** Under certain circumstances, contamination of the boiler makeup water supply via a faulty blowdown heat recovery heat exchanger can result in contamination of the water being supplied as makeup to a recovery boiler.

### Key Chemical Control Variables

Recovery boiler blowdown water can contain a variety of impurities. The composition and concentration of the impurities is impacted by feedwater quality, chemical program selection (as a function of boiler operating pressure), extraneous contaminate ingress sources, and blowdown control.

When either feedwater or steam is suspected of being contaminated (discernable and sustainable step change), operators should validate their feedwater test results and, once validated, follow the ESOPs that are in place to troubleshoot the problem and identify the source of contamination.

If the source of contamination is boiler blowdown water, then the composition or profile of the contaminants will typically reflect boiler water chemistry.

### 3.4.3 Key Maintenance Practices & Protocols

#### System Reliability Impact Assessment

If the purity of the steam exiting the continuous blowdown flash tank, or the purity of the feedwater makeup exiting the heat exchanger (if used) is compromised, it can usually be attributed to one or more of the following:

- Poor mechanical separation
- Poor level control
- Heat exchanger integrity
- Excessive blowdown flows (potential overflow condition).

#### Inspection Techniques

**Flash Tank:**

- If there are baffles in the vessel, check for proper alignment
- Inspect the level control shell penetrations for obstructions
- Inspect the blowdown level sensing lines if present.

**Heat Exchanger:**

- Verify proper operation of any level sensing device
- If a leak is suspected, perform nondestructive testing on the heat exchanger.
Blowdown Heat Recovery Systems

**Inspection Frequency**

A periodic visual inspection schedule should be established. There may also be code requirements which should be considered. Inspection SOPs should be developed and implemented.

<table>
<thead>
<tr>
<th>3.4.4 SOPs</th>
</tr>
</thead>
<tbody>
<tr>
<td>N/A</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>3.4.5 ESOPs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>3.4.5.1 - ESOP - Steam Contamination from the Continuous Blowdown System</strong> - It is a best practice to have ESOPs in place that address contamination of the steam. The continuous blowdown tank can be one of many potential sources of steam contamination. If the blowdown tank (flash tank) is suspect and if the flashed steam is utilized in the deaerator, there will be an elevation in feedwater conductivity with no elevation in makeup water conductivity.</td>
</tr>
</tbody>
</table>

| **3.4.5.2 - ESOP - Processed Water Contamination of Continuous Blowdown System** - If RO or ion exchange processed water is supplied to the blowdown flash tank heat exchanger and that processed water is utilized as makeup to the recovery boiler feedwater system, it is a best practice to have ESOPs in place that address process water contamination of the makeup water processed through the continuous blowdown heat exchanger. |

The blowdown tank heat exchanger can be one of many potential sources of makeup water contamination. In those cases where the blowdown water pressure at the heat exchanger exceeds the processed water pressure and the heat exchanger becomes suspect, there may be an elevation in conductivity in the water being supplied to the feedwater system. The extent of contamination will be a function of the conductivity levels being maintained in the recovery boiler blowdown water and the extent and nature of the heat exchanger leak. |

<table>
<thead>
<tr>
<th>3.4.6 Monitoring</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>3.4.6.1 - Monitoring - Feedwater Conductivity Elevation &amp; the Continuous Blowdown System</strong> - For out-of-compliance results (alarm condition), determine if any changes in feedwater conductivity levels can be attributed to the makeup water supply; the condensate supply or the steam supply to the deaerator.</td>
</tr>
</tbody>
</table>

If a continuous blowdown heat exchanger is suspect, manually test the processed water downstream of the heat exchanger and look for an increase in the conductivity of the processed water supply. |

Review your troubleshooting guidelines (ESOPs) that address recovery boiler feedwater contamination. |

Review your troubleshooting guidelines (ESOPs) that address recovery boiler condensate system contamination. |
### Blowdown Heat Recovery Systems

It is a best practice to install a high level alarm on the continuous blowdown flash tank.

Check your feedwater conductivity alarm and control setpoints.

#### 3.4.7 Inspection/Documentation

<table>
<thead>
<tr>
<th>3.4.7.1 - Inspection/Documentation - Continuous Blowdown Tank Heat Exchanger</th>
<th>If a heat exchanger is part of the heat recovery system, first, note the pressure relationships of the two fluids entering/exiting the heat exchanger. If the blowdown water can contaminate the process water, instrumentation should be in place to detect and alarm to that condition. If a blowdown heat exchanger is suspect of leaking, isolate the exchanger and observe the impact upon water chemistry at points downstream of the suspect exchanger.</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.4.7.2 - Inspection/Documentation - Continuous Blowdown Tank Level Control</td>
<td>Since the boiler blowdown contains dissolved and suspended solids, it is critical that the blowdown water in the flash tank be mechanically controlled at a level that minimizes the potential for contamination of the flashed steam. <strong>Note:</strong> Operating the flash tank outside the design specifications (high load conditions, start-up, etc.) can result in boiler water contamination of the flashed steam.</td>
</tr>
<tr>
<td>3.4.7.3 - Inspection/Documentation - Continuous Blowdown Piping</td>
<td>The blowdown flash tank(s) level should be checked visually on a routine basis as part of the operator’s walkdown.</td>
</tr>
<tr>
<td>3.4.7.4 - Inspection/Documentation - Blowdown Piping</td>
<td>There should be a periodic inspection of blowdown piping for thinning due to corrosion.</td>
</tr>
</tbody>
</table>
4.1 Economizer Systems

4.1.1 Design & Operational Considerations

<table>
<thead>
<tr>
<th>System Overview</th>
</tr>
</thead>
<tbody>
<tr>
<td>The economizer is the last feedwater preheating step before the feedwater enters the steam drum. The economizer recovers heat from the flue gas, elevating feedwater temperature.</td>
</tr>
</tbody>
</table>

Most recovery boiler economizers are integral to the boiler. Typically, they are once through flow bottom-to-top with or without headers to distribute flow at very low velocity to the steam drum. The water pressure must exceed steam drum pressure and, although economizers are located in relatively low temperature portions of the boiler, elevated approach temperatures can result in premature boiling within the upper portion of the economizer. Premature boiling can impact circulation within the boiler circuits and can impact boiler start-up.

The economizer system may incorporate a feedwater air heater (heat exchanger). The economizer may also consist of one or more sections.

The economizer is subject to the same contaminant concerns as the feedwater piping, but the heat input in this portion of the water circuit, coupled with the low velocities, makes the economizer the first place that contaminants may manifest themselves.

The low feedwater velocities can create a number of problems specific to particulate iron buildup within the lower extremities of the economizer circuitry. If coupled with oxygen and/or non-compliant water parameters or chemistries, concerns regarding corrosion heighten. In many systems the key problem, iron particulate, can transport into the boiler drum, tube and header circuitry.
Economizer Systems

Basic System Flow Path

The following illustration represents basic economizer circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for this system are from the point where the feedwater piping enters the economizer inlet header to the steam drum inlet penetration.
**Economizer Systems**

### Basic System Component Design

A conventional economizer system is comprised of:

- Sample point at the inlet of the economizer
- Sample point at the outlet of the economizer
- Heat exchangers (flue gas/feedwater and air/feedwater are optional and not illustrated)
- Boiler water treatment chemical injection quills (optional and not illustrated).

Economizer outlet temperature should be monitored and be below the saturation temperature per alarm setpoint. Refer to OEM recommendation.

### Basic System Control Technology

With the exception of economizer ESP and rapid drain valve(s), a basic economizer system does not have any system controls.

### 4.1.2 Chemical Treatment & Control Considerations

#### Water/Steam Purity Impact Assessment

From a chemical treatment perspective, the integrity of the economizer must be sustained over time without benefit of routine inspection of the various circuits and headers. Corrosion or deposition within circuitry may result in premature component failure and/or affect the components and circuits located downstream of the economizer. If the location of the failure is above a baffle, water may enter the furnace, resulting in a critical exposure. Therefore, the prescribed guidelines and monitoring tools utilized to assess tube surface conditions and metallurgical integrity should be routinely reviewed and updated as required.

#### Key Chemical Control Variables

American Society of Mechanical Engineers (ASME) guidelines should be consulted for a full discussion of chemical control variables, including dissolved oxygen, pH, conductivity, iron, copper, and hardness (ASME guidelines are in the Appendix section).

Mills should maintain ESOPs for reacting to discernable and sustainable out-of-bound feedwater parameters. At a minimum, these procedures should address oxygen, iron, pH, hardness, and conductivity.

When contamination is suspected, operators should validate their test results and, once validated, follow the feedwater and economizer ESOPs that are in place to troubleshoot the problem. Ensure that the sample conditioning station is not the source of the apparent contamination.
### 4.1.3 Key Maintenance Practices & Protocols

<table>
<thead>
<tr>
<th><strong>System Reliability Impact Assessment</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Excessive oxygen can cause internal pitting within the economizer. Good dissolved oxygen removal is essential.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Inspection Techniques</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>It is best practice to periodically remove the handhole caps in the economizer headers and conduct boroscope inspection, nondestructive testing, and/or periodic tube sampling of the economizer. In all cases, the purpose is to monitor for any evidence of deposits or ( \text{O}_2 ) pitting.</td>
</tr>
<tr>
<td>Consideration should also be given for periodic iron studies across the economizer. Facilities should consult their water treatment subject matter experts to determine need, frequency, and methodology.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Inspection Frequency</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>The need to inspect the economizer and the frequency of inspection are driven by a number of factors: Economizer operating history and feedwater quality being two key factors. It is recommended that a timeline that best fits your operating circumstances be established.</td>
</tr>
</tbody>
</table>

### 4.1.4 SOPs

**4.1.4.1 - SOP - Economizer Iron Monitoring (In/Out)** - An SOP should be in place to monitor iron in and out of the economizer. At a minimum, sampling protocols should be in place that specify flow rates and, if the flow is intermittent, line purge requirements. If a sample line experiences some restriction in flow (over time), an SOP should be in place to address line purge and re-stabilization practices. Refer to TAPPI TIP 0416-03 "Water quality and monitoring requirements for paper mill boilers operating on high purity feedwater" and 0416-14 "Water quality guidelines and monitoring requirements for paper mill boilers operating with softened makeup water."

### 4.1.5 ESOPs

| **N/A** |
### 4.1.6 Monitoring

**4.1.6.1 - Monitoring - Economizer Iron & Oxygen Testing** - There are a variety of tests that measure iron in its different oxidation states. These tests can include visual colorimetric, spectrophotometric analysis, and filtration. The objective of the testing is to identify iron particulate and/or iron corrosion by-products that may contaminate the feedwater supply and the boiler water.

The economizer itself can be a source of, or repository for, iron contamination. For more information on iron sampling and testing, contact/refer to one or more of the following:

- Your water treatment subject matter expert
- TAPPI TIP 0416-05 "Response to contamination of high purity boiler feedwater."

ESOPs shall be in place that address ASME guidelines for iron levels in the boiler feedwater. Refer to the ASME guidelines contained in the Appendix section.

**4.1.6.2 - Monitoring - Economizer Sample Coolers** - High pressure sample coolers are required on economizer sampling systems. A properly designed and constructed high pressure sample cooling system should be in place to monitor water quality across the economizer. Utilization of pre- and post-economizer sample points will provide an indication of whether iron is being removed or deposited in the economizer.

### 4.1.7 Inspection/Documentation

**4.1.7.1 - Inspection/Documentation - Economizer Chemical Feed Point** - If boiler water treatment chemicals are added upstream of the economizer, the compatibility of these chemicals must be reviewed to determine what potential effects (if any) they may have on the economizer.

As stated earlier, a sample point downstream of the economizer is recommended. Appropriate sample flows must be maintained to ensure that the sample is representative of the process water flow. Sample temperature and time lag must be taken into account when designing these sample points.

Chemical injection quills should be of proper design and materials of construction.

**4.1.7.2 - Inspection/Documentation - Economizer Inspection Tube Sampling** - An economizer tube sample should be taken and inspected at regular intervals. The frequency of sampling and inspection depends on company policy, water consultant guidelines, and as history of economizer tube samples analysis dictates. The composition of the tubes must be analyzed for the presence of contaminants in addition to iron. The tubes must also be inspected for pitting. Facilities should establish written maintenance protocols that determine the scope and frequency of economizer inspections and tube sampling.
**Economizer Systems**

<table>
<thead>
<tr>
<th>4.1.7.3 - Inspection/Documentation - Economizer Boroscope Inspection</th>
<th>If there is scheduled economizer repair work, it is best practice to inspect, via boroscope, the open circuit.</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.1.7.4 - Inspection/Documentation - Economizer Root Cause Analysis</td>
<td>If there is an economizer tube failure, a root cause analysis should be conducted.</td>
</tr>
</tbody>
</table>
4.2 Drum, Tube & Header Circuitry

4.2.1 Design & Operational Considerations

System Overview

The boiler water/steam circuitry is designed to provide for the generation and separation of steam from boiler water.

Basic System Flow Path

The following illustration represents basic drum, tube, and header circuitry. Recovery boiler operating systems may vary with respect to component and circuit design. Any variation may impact how the guidelines are employed. The boundaries for the system are the boiler steam drum inlet and the superheater outlet.
# Drum, Tube and Header Circuitry

<table>
<thead>
<tr>
<th><strong>Basic System Component Design</strong></th>
</tr>
</thead>
</table>

**Steam Drum** - The steam drum is the primary location where water level is controlled, feedwater is mixed with boiler water, steam is separated from the steam/water mixture, some dissolved and suspended solids present in the water portion of the mixture are removed via a continuous blowdown line, and internal chemical treatments may be applied.

Any modifications to the steam drum internals may impact water level, circulation, steam/water separation, chemical treatment, and blowdown control.

**Natural Circulation** - As recovery boiler feedwater is converted into steam, the water flow through the furnace circuits is driven by the difference in density of fluids in the risers and downcomers. It is essential that circulation be maintained as per the manufacturer’s design to maximize the reliability of all recovery boiler tube and header circuits.

**Downcomer Circuits** - Under natural circulation conditions, downcomer circuits supply the lower furnace circuits. To ensure that the flow of water is predictable, the downcomer circuits are not typically subject to high heat input. Operating conditions that would serve to significantly elevate the water temperature in any of those downcomer circuits may alter the circulation in any furnace circuits.

**Lower Waterwall & Floor Tube Circuits** - The lower furnace waterwall, floor headers, and tube circuits are supplied with water that will become a steam/water mixture.

Deposits on boiler metal surfaces may reduce the rate of heat transfer and alter the location within the furnace where the heat transfer takes place.

In a recovery boiler, high rates of heat input are to be expected within the lower waterwall region. However, the location of maximum heat transfer can be altered by changes in operating practices and/or design modifications.

**Upper Waterwall Circuits** - The upper waterwall tube circuits are typically undergoing two-phase flow and, generally, are subjected to a slightly lower heat flux when compared to the lower furnace. The location of maximum heat input can vary, which can influence two-phase flow steam/water ratios.

Where the recovery boiler furnace is of composite materials of construction, the furnace area immediately above the composite weld line can be prone to higher waterside deposition.

**Screen Tube & Upper Header Circuits** - The screen tube and upper header circuits are subjected to similar heat input as the upper waterwall circuits and are prone to similar two-phase flow related concerns that can be complicated by their slope, or lack thereof, within the furnace. These circuits tend to be difficult to drain and, due to their location within the furnace, are not often inspected and seldom undergo metallurgical examination.
### Drum, Tube and Header Circuitry

**Superheater Circuits** - Saturated steam flows from the steam drum into the superheater circuitry. There are several factors that can impact circuit reliability:

- Start-up and shutdown procedures
- Steam purity
- Front fill or back fill practices (front fill is steam drum to superheater fill and back fill is superheater to steam drum)
- Fill water quality and chemistry
- Attemperation water quality
- Steam drum internal modifications
- Superheater layup practices.

### Basic System Control Technology

Drum level control is key to controlling carryover, carryunder, and overall waterside control:

- The two-element level control system is not as desirable as three-element level control
- Drum centerline is not always the optimal operating level condition. Reference boiler manufacturer's recommendations.

### 4.2.2 Chemical Treatment & Control Considerations

**Water/Steam Purity Impact Assessment**

A number of water treatment chemistry considerations can impact recovery boiler waterside conditions from a scale and/or corrosion perspective. The water treatment program should be selected based upon:

- Boiler operating pressure
- Boiler operating history
- ASME guidelines for the feedwater and boiler water
- Site specific steam purity guidelines
- Other system design factors (thermal, mechanical, chemical, and operational) may influence treatment program choice
- Overall economizer and boiler waterside tube surface conditions (based upon operating history from water quality and contaminant ingress perspectives and deposit weight density (DWD)).

In all cases you should consult with your boiler water treatment subject matter experts for water treatment program recommendations.
## Key Chemical Control Variables

There are a number of factors that can influence chemical treatment program and control:

### Mechanical Factors -

- **Blowdown line relative to feedwater pipe orientation and point of chemical addition.** The primary concern is that the boiler water that enters the continuous blowdown line is representative of what would be expected with regard to overall drum and circuit water chemistry. If the feedwater orifices are directed at the continuous blowdown orifices, the cycle chemistry is misrepresented.

- **Feedwater pipe orientation.** The feedwater pipe orientation should be as prescribed by the boiler manufacturer or, in the case of a retrofit to the boiler, as per the boiler manufacturer making that retrofit.

- **Chemical feed line location & orientation** (if an internal feed line in the steam drum is utilized on a continuous basis). Please refer to the first two mechanical considerations when assessing chemical feed line location and orientation.

### Design & Operational Factors -

- **Boiler heat input.** Changes in design and operating conditions have the potential to change recovery boiler heat input. Changes in where maximum heat transfer will take place can heighten chemical sensitivity in certain circuits and may require a review of chemical treatment control strategy and program selection.

- **Boiler operating pressure.** A change in operating pressure (sustained or intermittent) may necessitate a change in treatment selection and/or chemical control strategy. If a change in operating pressure has been experienced or is being considered, consult with your boiler manufacturer and water treatment subject matter experts.

- **Boiler feedwater water quality.** Any design modification to the pre-treatment or external treatment system (equipment or procedures) can create a discernable and sustainable change in feedwater quality and may require a change in treatment selection and/or control to meet corresponding ASME guidelines based upon the conditions encountered.

In all cases you should consult your water treatment subject matter experts when a change in water quality has taken place or when a change in the makeup or the condensate treatment processing system(s) is being considered.

### Other Factors that Affect Chemical Treatment Program Selection & Performance

- **Elevated dissolved oxygen levels.** A sustained elevation (reading greater than 10 ppb) in feedwater dissolved oxygen levels can impact chemical treatment performance and boiler circuit metallurgy.

- **Elevated boiler iron levels.** Iron can either be transported into the boiler or generated in situ within the boiler circuits.
Drum, Tube and Header Circuitry

The following are ASME feedwater guidelines for iron at various boiler operating pressures:

<table>
<thead>
<tr>
<th>Pressure (psig)</th>
<th>Iron Level (ppb)</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 300</td>
<td>100 ppb</td>
</tr>
<tr>
<td>301 - 450</td>
<td>50 ppb</td>
</tr>
<tr>
<td>451 - 600</td>
<td>30 ppb</td>
</tr>
<tr>
<td>601 - 750</td>
<td>25 ppb</td>
</tr>
<tr>
<td>751 - 1000</td>
<td>20 ppb</td>
</tr>
<tr>
<td>1001 - 2000</td>
<td>10 ppb</td>
</tr>
</tbody>
</table>

The presence of high iron levels in boiler water may be associated with one or more of the following:

- Iron ingress (either continuous or intermittent) from the condensate system
- Following a boiler start-up
- Following/during a change in treatment chemistry
- Following/during an acid or alkali excursion
- Excessive feed of iron dispersants
- Underdeposit corrosion mechanisms
- Lack of a passivation environment following a chemical cleaning
- Incomplete purge of particulate iron from all boiler circuitry following a chemical cleaning.

Chemical treatment parameters for iron control should be determined by your water treatment SME in keeping with the conditions encountered. It is always advisable to have baseline information before making and/or assessing any chemical changes to the routine iron treatment and control scheme.

- **The presence of known deposits within the recovery boiler circuitry.** The presence of deposits in boiler circuits and headers increases the concerns regarding treatment program selection.

Waterside deposits have the potential to migrate within the boiler. The movement and relocation can serve to promote corrosion and/or deposition in circuits and headers that may have previously been considered clean and free of deposition.

The movement of existing deposits within a recovery boiler can be caused by significant thermal, mechanical, chemical, and operational changes within the recovery boiler system. Treatment program selection and dosages should be predicated upon knowledge of those changes. The selection of a location for the removal of boiler tube section for DWD analysis may also be affected by these changes.

In all cases you should consult with your water treatment subject matter experts if the recovery boiler has a history of waterside deposition.

- **Changes to the existing treatment program.** A chemical cleaning may be required before changing a chemical treatment program. Please refer to the BLRBAC Chemical Cleaning Guidelines for additional information on when to consider chemical cleaning a recovery boiler.

- **Unexpected changes in the feedwater chemistry.** In most, but not all, instances an unexpected change in the feedwater chemistry may be accompanied by an increase in
feedwater conductivity. In systems where feedwater pH is monitored, correlations between changes in pH and conductivity can help identify a contaminant type and source.

**Note:** If you observe a discernable and sustainable change in program chemistry control parameters you should immediately reference your emergency response procedures and contact your water treatment subject matter experts.

Refer to TAPPI TIP 0416-05 "Response to contamination of high purity boiler feedwater."

- **Steam purity considerations.** Recovery boilers shall have a historical database (preferably a baseline) of steam purity-related information. Continuous sodium monitoring is recommended where generating turbines are supplied steam from the recovery boiler.

Steam purity analysis of superheated steam is the preferred monitoring method for steam being supplied to generating turbines.

Steam purity analysis of saturated steam is the preferred monitoring method to determine if chemical and/or mechanical induced carryover from the steam drum is occurring.

- **Historical information.** Collection and consolidation of water quality data and water upset incidents can be beneficial for historical review of recovery boiler operations.

**Note:** In all cases, you should provide your water treatment subject matter experts with a historical overview of past water treatment-related anomalies.

**Program Selection Options** - Dependent on factors such as water quality, operating pressure, boiler history and/or control ability. Current available treatment options for recovery boilers are:

- All organic (lower pressure applications)
- Alkaline phosphate (both low and high PO₄ control setpoints)
- Coordinated pH control
- Congruent control
- Equilibrium control.

In all cases, you should provide your water treatment subject matter experts with a historical overview of past water treatment-related anomalies.

**Chemical Feed & Monitoring Practices** -

- Care must be taken in selecting chemical feed points and delivery systems. Improperly designed chemical delivery systems can compromise the ability to control water chemistry.

- Sampling points should be selected that will allow you to properly monitor chemical concentrations. An example of suggested sample points can be found in TAPPI TIP 0416-03 "Water quality and monitoring requirements for paper mill boilers operating on high purity feedwater" and 0416-14 "Water quality guidelines and monitoring requirements for paper mill boilers operating with softened makeup water."

- Boiler water sample streams shall have proper flow to ensure that they are representative of the water in the unit. The temperature of the samples should be
Drum, Tube and Header Circuitry

<table>
<thead>
<tr>
<th>Conditioned to 25°C. Variation from this temperature will affect conductivity and pH, and require compensation. The sample stream shall flow continuously.</th>
</tr>
</thead>
<tbody>
<tr>
<td>- An up-to-date validated system chemical feed point and delivery schematic will minimize the potential for a chemical misapplication. In addition, a detailed review of the chemical delivery methodology will provide a better understanding of what can be expected in terms of statistical control.</td>
</tr>
</tbody>
</table>

### 4.2.3 Key Maintenance Practices & Protocols

#### System Reliability Impact Assessment

Properly maintained drums, tubes and header circuitry are essential to the safe and continued operation of any boiler. The methods and techniques employed to accomplish this can be many and diverse. Some of the more common (and beneficial) tools and techniques are outlined below.

#### Inspection Techniques

Qualified individuals should perform visual inspections in conjunction with appropriate nondestructive examination, periodic analysis of tube samples, and camera and/or fiber optics of accessible tube and header circuits.

#### Inspection Frequency

The frequency of inspections for the drums, tubes, and headers is mill location specific. The steam drum should be inspected during every major maintenance outage. Inspection of the tube and header circuits will be driven by any number of factors:

- Pressure part accessibility (tube sampling, repairs or replacement, etc.)
- Mill-specific header inspection guidelines
- Areas identified by destructive and/or nondestructive examination.

Tube sample frequency and protocols vary widely throughout the industry. It is recommended that tube samples be taken at a frequency not to exceed three years. It must be noted that samples may need to be obtained more frequently if upsets have occurred, deposits are suspected, or chemical cleaning protocols are being established.

#### 4.2.4 SOPs

**4.2.4.1 - SOP - Front & Back Filling the Boiler** - For hydrostatic testing, it is recommended that the superheater be back filled with demineralized water or condensate which is free of non-volatile components.

The chemical treatment selected should be all volatile. The type and level of treatment selected will typically be influenced by the back fill water characteristics and the anticipated duration of the lay-up period.
It is not recommended that you front fill the superheater with boiler water. Boiler water can contain chemicals and solids that, once introduced into the superheater section, may cause deposition and/or corrosion within the superheater circuitry.

### 4.2.4.2 - SOP - Boiler Water Testing
Boiler water samples shall be tested at intervals of 4 - 6 hours. Intervals between tests can be longer if continuous monitoring is utilized. Manual entry test data should be retained in accordance with mill document retention policies. At a minimum, tests should include pH, conductivity, silica, and treatment chemical concentration. In low pressure boiler applications testing should also include P, M and/or OH alkalinity and sulfite.

### 4.2.4.3 - SOP - Boiler Water Chemistry Outside Normal Control Boundaries
An SOP shall be in place that addresses the blowdown and/or chemical feed action steps to be taken by the operator to bring the following water treatment parameters back into control:

- High/Low Boiler Water pH
- High Boiler Water Silica Levels
- High Boiler Water Iron Levels
- High Boiler Water Conductivity
- High/Low Boiler Water Chemical Treatment Levels
- High/Low Boiler Water Alkalinity

An SOP shall be available for every boiler water test run by the operators.

### 4.2.4.4 - SOP - Hardness Testing
Feedwater hardness limitations are based upon boiler operating pressure and the processing capabilities of the makeup water support systems. An SOP shall be in place that addresses hardness test protocols.

There are two hardness test methods that are typically employed:

- Colorimetric/titration low level limit of detection (100 ppb)
- Spectrophotometric ultra-low level (20 ppb).

**Colorimetric Titration Test** - Due to limitations in level of detection and differences in visual interpretation, the colorimetric titration test should only be used with softened water makeup.

The lowest level of detection is at best 100 ppb. If this method is employed, the results as recorded by the operator should be routinely validated utilizing a methodology that has a < 100 ppb level of detection.

A step change in routine test results should be addressed immediately.

**Spectrophotometric Analysis** - The ultra-low hardness test is the preferred method to test for hardness in high purity feedwater systems. Due to variability in the results obtained in the field, site specific control boundaries should be assigned (i.e., 20 - 80 ppb) and monitored. Focus should be given to any step change in hardness levels.
## 4.2.5 ESOPs

### 4.2.5.1 - ESOP - Boiler Water High/Low pH Conditions - ESOPs shall be in place to address both high and low boiler water pH conditions. The ESOPs should include:

- Test validation and verification guidelines for either condition (pH meter validation, etc.)
- Procedure to confirm chemical delivery systems are functioning as specified
- A check and confirm status of feedwater conductivity alarm status relative to setpoint
- Contaminant identification guidelines (makeup water, condensate return streams)
- A list of water treatment subject matter experts to be contacted in the event of an emergency
- A troubleshooting decision tree that delineates action steps to be taken
- A description of water support system component bypass capabilities (if any exist).

### 4.2.5.2 - ESOP - High Boiler Water pH Excursion - Coordinated Phosphate -

**Condition I** - Boiler water pH > 0.2 units above the normal operating upper limit. *(Note: The addition of acid for boiler water pH control is not recommended.)*

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

**Step 1:** Search for the source of contamination in accordance with your SOP guideline for contaminant ingress identification.

**Step 2:** Increase the frequency of silica, conductivity and pH testing associated with the following systems:

- Feedwater
- Turbine condensate (if applicable)
- Saturated and/or superheated steam (if applicable).

**Step 3:** Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

**Step 4:** Suggested next step (TAPPI TIP 0416-05):

- If steam sodium > 20 ppb - consider removing affected steam turbines from service
- If steam sodium > 100 ppb - consider removing the boiler from service.

In all cases consult the turbine manufacturer for specific limits.

**Condition II** - Boiler water pH deviation control > 0.2 units above the normal operating upper limit and the pH is ≥ 10.5. *(Note: The addition of acid for boiler water pH control is not recommended.)*

Refer to ESOP in **4.2.5.1** then proceed to the steps below.

**Step 1:** Refer to your emergency chemical feed and control guidelines and increase the feed of chemicals as delineated by the water treatment subject matter experts in accordance with the higher boiler blowdown control strategy that is in place.
<table>
<thead>
<tr>
<th>Step 2:</th>
<th>Search for the source of contamination in accordance with 4.2.4.3.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Step 3:</td>
<td>Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:</td>
</tr>
<tr>
<td></td>
<td>- Feedwater</td>
</tr>
<tr>
<td></td>
<td>- Turbine condensate (if applicable)</td>
</tr>
<tr>
<td></td>
<td>- Saturated and/or superheated steam (if applicable).</td>
</tr>
<tr>
<td>Step 4:</td>
<td>Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.</td>
</tr>
<tr>
<td>Step 5:</td>
<td>Suggested next step (TAPPI TIP 0416-05):</td>
</tr>
<tr>
<td></td>
<td>- Discontinue any caustic feed.</td>
</tr>
<tr>
<td></td>
<td>- If you have a two-drum boiler, initiate short duration mud drum blows at 30 minute intervals.</td>
</tr>
<tr>
<td></td>
<td>- If boiler water pH exceeds 11 for &gt; 24 hours consider removing the boiler from service.</td>
</tr>
</tbody>
</table>
4.2.5.3 - ESOP - Low Boiler Water pH Excursion - Coordinated pH Programs -

**Condition I** - Boiler water pH > 0.2 units below the normal operating lower control boundary. For recovery boilers operating under a coordinated phosphate program, the suggested lower pH control boundary is ≥ 9.0 pH units.

Refer to ESOP in 4.2.5.1 then proceed to the steps below.

**Step 1:** Search for the source of contamination in accordance with 4.2.5.1.

**Step 2:** Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:

- Turbine condensate (if applicable)
- Makeup water to the deaerator
- Condensate to the deaerator
- Feedwater leaving the deaerator
- Attemperator supply water (if applicable).

**Step 3:** Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

**Step 4:** Suggested next step (TAPPI TIP 0416-05):

- Feed trisodium phosphate and discontinue feed of any other phosphate with a lower Na/PO₄ mole ratio.
- Maintain phosphate in normal range.

**Condition II** - Boiler water pH deviation from operating pH control > 0.2 units below the normal operating lower limit and pH 8.0 - 8.6.

Refer to ESOP in 4.2.5.1 then proceed to the steps below.

**Step 1:** Increase the feed of chemicals as delineated by the water treatment subject matter experts in accordance with the higher boiler blowdown control strategy that is in place.

**Step 2:** Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:

- Turbine condensate (if applicable)
- Makeup water to the deaerator
- Condensate to the deaerator
- Feedwater leaving the deaerator
- Attemperator supply water.
- Saturated and/or superheated steam (if applicable).

**Step 3:** Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.
Drum, Tube and Header Circuitry

Step 4: Suggested next step (TAPPI TIP 0416-05):

- Supplement trisodium phosphate feed with caustic to re-establish normal boiler water pH.
- Increase dispersant feed to maintain normal concentration under increased blowdown conditions.
- If steam purity remains compromised, open blowdown and increase anti-foam feed.
- If steam sodium > 20 ppb - consider removing affected steam turbines from service.
- If steam sodium > 100 ppb - consider removing the boiler from service.

Note: To avoid inadvertent overfeed of caustic, the Low Boiler Water pH Excursion ESOP should contain a site-specific guide for caustic feed to re-establish normal boiler water pH. For plants with demineralized makeup, typically 1-12 ppm of caustic (NaOH) is needed to restore pH. 1 ppm NaOH equates to ~5 mL of 50% caustic /1000 gallons of boiler volume. The caustic solution is typically diluted in a phosphate solution or water. If flake caustic is used, it must be fully dissolved and diluted before feeding to the boiler. Do not allow caustic with a pH over 13 to sit stagnant in the chemical feed lines for extended periods.

Condition III - Boiler water pH between 8.0 and 6.0 and decreasing.

Refer to ESOP in 4.2.5.1 then proceed to the steps below.

Step 1: Increase the feed of chemicals as delineated by the water treatment subject matter experts in accordance with the higher boiler blowdown control strategy that is in place.

Step 2: Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:

- Turbine condensate (if applicable)
- Makeup water to the deaerator
- Condensate to the deaerator
- Feedwater leaving the deaerator
- Attemperator supply water.
- Saturated and/or superheated steam (if applicable).

Step 3: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 4: Suggested next step (TAPPI TIP 0416-05):

- Discontinue any caustic feed.
- If you have a two-drum boiler, initiate short duration mud drum blows at 30 minute intervals.
- If boiler water pH does not stabilize or reverse the downward slope within 8 hours the boiler should be removed from service.
<table>
<thead>
<tr>
<th>Drum, Tube and Header Circuitry</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Condition IV</strong> - Boiler water pH $&lt; 6.0$ pH units.</td>
</tr>
<tr>
<td><strong>Step 1:</strong> Suggested next step (TAPPI TIP 0416-05):</td>
</tr>
<tr>
<td>- Immediately remove boiler from service</td>
</tr>
<tr>
<td>- Consider chemical cleaning before re-start</td>
</tr>
<tr>
<td>- Confirm that the source of the excursion has been identified and eliminated before returning the unit to service.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>4.2.5.4 - ESOP - High Boiler Water Silica</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Condition I</strong> - Boiler water silica between upper control limit and <strong>120%</strong> of that limit.</td>
</tr>
<tr>
<td>Refer to ESOP in <strong>4.2.5.1</strong> then proceed to the steps below.</td>
</tr>
<tr>
<td><strong>Step 1:</strong> Continue to monitor (at a higher frequency) the silica control parameters associated with the following systems:</td>
</tr>
<tr>
<td>- Makeup water (demineralizers, etc.)</td>
</tr>
<tr>
<td>- Feedwater</td>
</tr>
<tr>
<td>- Attemperator</td>
</tr>
<tr>
<td>- Turbine condensate (if applicable)</td>
</tr>
<tr>
<td>- Saturated and/or superheated steam (if applicable).</td>
</tr>
<tr>
<td><strong>Step 2:</strong> Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.</td>
</tr>
<tr>
<td><strong>Step 3:</strong> Suggested next step (TAPPI TIP 0416-05):</td>
</tr>
<tr>
<td>- If silica levels exceed turbine manufacturer specifications follow the turbine manufacturer guidelines.</td>
</tr>
</tbody>
</table>

| **Condition II** - Boiler water silica between **120%** and **140%** of the upper limit. |
| Refer to ESOP in **4.2.5.1** then proceed to the steps below. |
| **Step 1:** Refer to your emergency chemical feed and control guidelines and increase the feed of chemicals as delineated by the water treatment subject matter experts in accordance with the higher boiler blowdown control strategy that is in place. |
| **Step 2:** Continue to monitor (at a higher frequency) the silica, conductivity, and pH control parameters associated with the following systems: |
| - Feedwater |
| - Turbine condensate (if applicable) |
| - Saturated and/or superheated steam (if applicable). |
| **Step 3:** Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored. |
Step 4: Suggested next step (TAPPI TIP 0416-05):
- Maximize continuous blowdown (refer to 3.4.7.3 to ensure blowdown heat recovery tank is capable of handling maximum flow).
- If you have a two-drum boiler, initiate short duration mud drum blows at 30 minute intervals if approved by the OEM.
- If silica levels exceed turbine manufacturer specifications follow the manufacturer guidelines.

**Condition III** - Boiler water silica exceeds 140% of the upper limit.

Refer to ESOP in 4.2.5.1 then proceed to the steps below.

Step 1: Refer to your emergency chemical feed and control guidelines and increase the feed of chemicals as delineated by the water treatment supplier in accordance with the higher boiler blowdown control strategy that is in place.

Step 2: Continue to monitor (at a higher frequency) the chemical control parameters associated with the following systems:
- Feedwater
- Turbine condensate (if applicable)
- Saturated and/or superheated steam (if applicable).

Step 3: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 4: Suggested next step (TAPPI TIP 0416-05):
- If these high levels persist, consider shutting down the boiler
- Identify and eliminate the contamination source and flush system prior to returning to service.

### 4.2.5.5 - ESOP - Feedwater Hardness Excursions Affecting Boiler Water Chemistry -

A discernable and sustainable step change in feedwater hardness levels may alter boiler water chemistry in high purity boiler water treatment control schemes (i.e., boiler water pH suppression). In the event hardness levels elevate, proceed to the following:

Step 1: Refer to the SOP on hardness testing and then proceed to verify test results.

Step 2: Refer to your emergency boiler blowdown control guidelines and employ the appropriate boiler blowdown control strategy.

Step 3: Contact your water treatment subject matter experts and immediately proceed to Step 4.

Step 4: Search for the source of contamination in accordance with the SOP guideline for contaminant ingress identification.
Step 5: Continue to monitor (at a higher frequency) hardness and conductivity levels associated with the following systems:

- Makeup water (deminerlizers, etc.)
- Feedwater
- Condensate return streams (including turbine condensate, if applicable).

Step 6: Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.

Step 7: Suggested next step (TAPPI TIP 0416-05):

- If you have a two-drum boiler, initiate short duration mud drum blows at 30 minute intervals.
- Refer to your emergency chemical feed and control guidelines and increase the feed of chemicals (dispersants, etc.) as delineated by the water treatment supplier in accordance with the higher boiler blowdown control strategy that is in place (ESOP).
- If feedwater hardness levels exceed 2 ppm for 24 hours or 5 ppm for 12 hours, consideration should be given to removing the boiler from service for inspection and a possible chemical cleaning.
- Identify and eliminate the contamination source and flush system prior to returning to service.

4.2.5.6 - ESOP - High FW Iron Levels Elevating Boiler Water Iron Levels - Baseline Iron Data

To address this ESOP there must be a boiler water iron testing program in place (Millipore iron testing and/or spectrophotometric iron testing).

There will be situations when iron levels will increase beyond established control limits. The iron can either be transported into the boiler or generated in situ within the boiler circuits.

It is recommended that, at a minimum, a baseline iron profile be established in order to proceed with any comparative iron study following any potential change in bulk boiler water chemistry.

Once established the following steps should be employed:

Step 1: Verify test results in accordance with your specific ESOP response guideline for high iron levels.

Step 2: Refer to your emergency boiler blowdown control guidelines and employ the appropriate boiler blowdown control strategy to lower iron levels.

Step 3: Contact your water treatment subject matter experts and immediately proceed to Step 4.

Step 4: Search for the source of contamination in accordance with the ESOP guideline for contaminant ingress identification.
### Drum, Tube and Header Circuitry

<table>
<thead>
<tr>
<th>Step 5:</th>
<th>Although boiler water capacity and scenario dependent, it would be advisable to alert the SME and the Utilities Department if after three days the normal upper iron control boundary is a factor of &gt; 3x and the previous 24 trend has reduced the iron levels by 50%.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Step 6:</td>
<td>Continue to monitor (at a higher frequency) iron associated with the following systems:</td>
</tr>
<tr>
<td></td>
<td>• Makeup water (demineralizers, etc.)</td>
</tr>
<tr>
<td></td>
<td>• Feedwater</td>
</tr>
<tr>
<td></td>
<td>• Boiler water</td>
</tr>
<tr>
<td></td>
<td>• Condensate return streams.</td>
</tr>
<tr>
<td>Step 7:</td>
<td>Interpret all pertinent data trends and attempt to identify step changes in any control parameter being monitored.</td>
</tr>
<tr>
<td>Step 8:</td>
<td>Suggested next step:</td>
</tr>
<tr>
<td></td>
<td>• If feedwater iron levels exceed 100 ppb for 24 hours or 300 ppb for 12 hours, consideration should be given to removing the boiler from service for inspection and a possible chemical cleaning.</td>
</tr>
<tr>
<td></td>
<td>• Identify and eliminate the contamination source and flush system prior to returning to service.</td>
</tr>
</tbody>
</table>

#### 4.2.5.7 - ESOP - RB Leak Detection

- Water chemistry mass balances require reliable and representative sampling, coupled with precision and accuracy in the testing that is employed (if/when the testing is manual and performed in the field).

To help confirm that a leak may exist and/or to determine its location, there are a number of leak detection methods that could support an operator's audio/visual assessment regarding a potential leak condition.

- Fireside acoustic (noise) indications and waterside steam, water and/or chemical mass balance determinations often can add credence to operator walkdown findings.

- Steam/water flow mass balances typically require either accurate flow measurements or a reliable set of operating conditions or trends to measure against a suspect change in flow.

Regardless of the type of leak detection monitoring method, an ESOP should be in place that defines what action steps are to be taken to validate the significance of any noise indication and any mass balance related finding. Details shall be provided regarding the water chemistry related and flow related parameters to be reviewed.

#### 4.2.6 Monitoring

##### 4.2.6.1 - Monitoring - Feedwater Inlet Temperature to the Drum

- Generation of steam in the feedwater (economizer) will impact circulation properties within the boiler circuitry. Adhere to the manufacturer's recommended requirement regarding minimum differential temperature between the economizer outlet and the steam drum. If the applicable instrumentation is in place, a high temperature alarm shall be used to alert operations to the potential of a steaming condition within the economizer.
## 4.2.6 Monitoring

### 4.2.6.2 Monitoring - Boiler Lower Furnace Temperature
Thermocouples in the lower furnace walls (usually between primary and secondary air) can provide a temperature profile of the high heat zone. In some instances, three-element chordal thermocouples can provide useful information regarding tube surface conditions.

### 4.2.6.3 Monitoring - Saturated Steam Purity
Steam purity measurement using an on-line sodium analyzer can be used to detect potential problems in the superheater and downstream steam users.

### 4.2.6.4 Monitoring - Cameras & Fiber Optics
Whenever tube samples are collected or a header is open for inspection, it is recommended a video inspection be performed.

### 4.2.6.5 Monitoring - Boiler Water Iron
If there are no iron filtration systems, process steam-related interlocks, or high particulate level divert systems in place, at a minimum, boiler water iron tests (filtration or photometric method) should be run every 8 - 12 hours. The results shall be recorded and retained in keeping with department data management practices.

### 4.2.6.6 Monitoring - Boiler Water Silica Monitoring (Colloidal Silica)
Since colloidal silica cannot be easily detected in the recovery feedwater system, at a minimum, boiler water silica tests should be run every 8 - 12 hours.

## 4.2.7 Inspection/Documentation

### 4.2.7.1 Inspection/Documentation - Steam Drum Blowdown Line Orientation
The blowdown line should be oriented to collect the boiler water with minimal influence from the feedwater line and chemical feed point. The blowdown line is typically oriented in the 12:00 position and should be free of any restrictions. Neither the feedwater line nor the chemical feed line orifices should be directed towards the blowdown line.

The feedwater line, chemical feed line, and blowdown line orifices should be oriented in accordance with manufacturer's guidelines and shall be verified every time they are removed for maintenance.

**Important**: Boiler cycles of concentration may not be accurately reported if the internal lines in a steam drum are incorrectly installed or improperly oriented.

### 4.2.7.2 Inspection/Documentation - Boiler Waterside Condition
Water quality analysis, deposition analysis, and metallurgical analysis (DWDs, locations, etc.) shall be documented and retained. Any changes in operating practices and upsets shall also be documented and communicated to water treatment subject matter experts.
### 4.2.7.3 - Inspection/Documentation - Boiler Water Treatment Sample Points
It is recommended that a sample extraction point survey be on file and updated annually or following any modification to the boiler and/or its water support system.

### 4.2.7.4 - Inspection/Documentation - Boiler Water Treatment Feed Points
It is recommended that a chemical feed point schematic be in place and updated when changes are made to feed point or chemistry.

### 4.2.7.5 - Inspection/Documentation - Boiler Visual Inspection Checklist
Thorough visual inspections are the first line of defense for any boiler and should be conducted at each major maintenance outage. An inspection checklist should be developed/maintained that is tailored for each area of each specific boiler.

### 4.2.7.6 - Inspection/Documentation - Boiler Visual Inspection Protocols
Visual inspections should be supplemented with appropriate NDE methods and with tube samples. The detailed protocols governing these supplemental inspections should be developed by the mill.

### 4.2.7.7 - Inspection/Documentation - Boiler NDE Program
Each mill should develop and/or maintain a program of NDE inspection as a supplement to the visual inspection.

It is suggested that any NDE results be tracked, trended and compared to minimal wall values via an established program or protocol. The establishment of "flag values" (values approx. 10% above minimum wall) can be a valuable tool in identifying areas of concern and planning/budgeting for needed repairs or replacement. Refer to TAPPI TIP 0402-18 "Ultrasonic testing (UT) for tube thickness in black liquor recovery boilers."

### 4.2.7.8 - Inspection/Documentation - Boiler Tube Deposit Weight Density
DWDs obtained from tube sample results should be analyzed and could be used to establish chemical cleaning frequency and chemical cleaning protocols.
<table>
<thead>
<tr>
<th><strong>4.2.7.9 - Inspection/Documentation - Boiler Steam Drum</strong></th>
<th>Inspect hardware integrity, baffle plate condition, and the general integrity of all major internals.</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Look for signs of any deposits in the drum, evidence of steam blanketing, or standing water. Obtain samples for analysis of any noted deposits and document the location.</td>
<td></td>
</tr>
<tr>
<td>• Check the physical condition of the drum for indications of any pitting or cracks, including ligament cracking.</td>
<td></td>
</tr>
<tr>
<td>• Check the physical condition of any tube plugs.</td>
<td></td>
</tr>
<tr>
<td>• Inspect for proper metal passivation and the condition and appearance of a normal drum level line (which would indicate consistent water level).</td>
<td></td>
</tr>
<tr>
<td>• Check the condition of steam space screens and chevrons.</td>
<td></td>
</tr>
<tr>
<td>• Check that all instrumentation taps are properly secured, open, and clear. Consider boroscopying as a means of verification.</td>
<td></td>
</tr>
<tr>
<td>• If accessible, inspect saturated steam sampling lines/headers.</td>
<td></td>
</tr>
<tr>
<td>• Check all threaded or flanged joints for evidence of leaks.</td>
<td></td>
</tr>
<tr>
<td>• Visually inspect the bottom seats of all safety valves.</td>
<td></td>
</tr>
<tr>
<td>• Consider boroscopying risers, downcomers, and generating bank tubes (which may require removal of belly plates) based on visual inspection results.</td>
<td></td>
</tr>
</tbody>
</table>

In addition to the visual inspection for two drum boilers, consideration should be given to periodic IRIS (scans) inspections as applicable. Refer to TAPPI TIP 0402-18.

<table>
<thead>
<tr>
<th><strong>4.2.7.10 - Inspection/Documentation - Boiler Feedwater Chemical Injection Quill</strong></th>
<th>Consider removing and inspecting the feedwater injection quill to ensure no pluggage or damage. NDE of downstream piping is recommended on major outages.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th><strong>4.2.7.11 - Inspection/Documentation - Mud Drum</strong></th>
<th>A visual inspection of all tubes for deposits. Specifically, check the metal surfaces into the bends of tubes in the 10:00 and 2:00 positions for unusual signs of deposition.</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Inspect the bottom of the drum for standing water or deposits.</td>
<td></td>
</tr>
<tr>
<td>• Ensure all downcomer covers are in place and that an accountability system is in place to ensure they are removed prior to start-up.</td>
<td></td>
</tr>
<tr>
<td>• If applicable, inspect the mud drum blowdown/baffles for proper clearance and orientation and that they are properly secured with the plates in place.</td>
<td></td>
</tr>
<tr>
<td>• Ensure the drum is properly and thoroughly cleaned prior to closeout (this should be part of the inspection checklist recommended above under steam drum).</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>4.2.7.12 - Inspection/Documentation - Boiler Headers</strong></th>
<th>Following major pressure part work and/or chemical cleaning, inspect affected headers for sludge and debris.</th>
</tr>
</thead>
</table>
### Drum, Tube and Header Circuitry

| 4.2.7.13 - Inspection/Documentation - Boiler Furnace - | A visual inspection from inside the furnace should be conducted on all accessible boiler tubes (i.e., floor, waterwalls, screen, generating bank, superheater, etc.). Particular attention should be paid to any cut lines or change of materials. Also look for any evidence of bulging or discontinuity. |
|------------------------------------------------------|
| 4.2.7.14 - Inspection/Documentation - Boiler Near Drum/Mud Drum Furnace - | In addition to the visual inspection, special consideration should be given to periodic near drum inspections where applicable. |
| 4.2.7.15 - Inspection/Documentation - Root Cause Analysis - | If there is a tube failure, a root cause analysis should be conducted. |