Identifying and Understanding Boiler Carryover and Carryunder

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Key Words: Carryover, Carryunder, Steam Separation, Deposition, Steam Monitoring, Superheaters

ABSTRACT

Boiler carryover and carryunder are two phenomena that occur frequently in industrial boiler applications. Because of its effects on overall boiler and process operations, more are familiar with boiler carryover; but knowing why it is occurring and the appropriate corrective actions is not so familiar. Boiler carry-under is far less frequent in its occurrence, and the amount of literature available on the subject is sparse. Also, because carry-under typically has more of a boiler design root cause, as opposed to operational or water chemistry, corrective actions are usually ad hoc if taken at all.

This paper attempts to highlight how carryunder and carryover occur, the tell-tale signs of each, and some ideas for correction where applicable. Also, because it is so critical and yet so rarely implemented, a detailed discussion about the proper online instrumentation necessary for monitoring carryover is provided. This includes key parameters, as well as an explanation as to why the selected parameters are important.

INTRODUCTION

A boiler is designed to produce high-quality steam, free of dissolved ions for final use in plant processes. A well-designed boiler considers heat flux in the various circuits, circulation ratios, operating pressures, feedwater temperature, and water chemistry expectations. When these elements are out of balance, carryover and/or carryunder can occur. The consequences of no action can manifest as equipment failure due to deposition and/or corrosion.

There are methods for monitoring and correcting carryover and carryunder that are not as widely used as one would hope. Improving the speed of identification, troubleshooting, and correction can significantly minimize plant downtime and the costs associated with lost revenue and repairs.

CARRYOVER PRIMER

Boiler water carryover is when boiler water and/or bulk water constituents are drawn up from the boiler drum into the steam header. There are two types of carryover, mechanical and vaporous, and it is important to understand the difference between the two since the corrective actions are different.

1. *Mechanical carryover* is when the boiler water carries into the steam header, passing through any steam separation equipment (assuming there is equipment), and makes its way into the steam system. Think of mechanical carryover as droplets leaving the boiler drum and heading down the steam piping.
2. *Vaporous carryover* is when ions that were originally ionized in the bulk water carryover with the steam in vaporous form. It is important to note that not all ions will vaporize at the typical pressures seen in industrial applications (including power generation). The most common ion of concern is silica at pressures above 900 psi, but copper can also vaporize above 2,400 psi. Vaporous carryover typically becomes a concern at pressures greater than 900 psi, but 1,800 psi is a point at which the silica volatilization curve really starts to influence the percentage of carryover. Think of vaporous carryover as water-free carryover of ions and molecules.

Understanding the difference between the two types of carryover is important when troubleshooting steam purity/quality issues, which brings up a good time to define the two. *Steam purity* is a reference to the ionic loading of the steam sample. For instance, a steam sample with 100 ppb of total dissolved solids (TDS) is less *pure* than a steam sample with 10 ppb of TDS. *Steam quality* is a reference to the moisture loading of the steam sample. For instance, a steam sample with 0.2% moisture is of less *quality* when compared to a steam sample with 0.1% moisture. The author gets asked all the time about measuring *Steam Quality*. A calorimeter can be used, but this is very expensive and measuring nonvolatile ions such as sodium is a more practical method. More on this in the *Monitoring* section.

All boilers have an inherent amount of acceptable mechanical carryover, which is measured as a percentage. Depending on the type of boiler, operating pressure, boiler circulation ratio, and type of separation equipment selected, these percentages can vary. Many like to consider a “normal percentage” of carryover, but experience has shown that each boiler application is different, and each boiler has its differences along the load curve. Determining actual percent carryover needs to be part of the commissioning and turnover process. The ASME *Consensus on Operating Practices for the Control of Feedwater and Boiler Water Chemistry in Industrial and Institutional Boilers* Is a good reference for mechanical carryover percentages based on application (Water Technology Subcommitte of the ASME Research and Technology Committee on Water and Steam in Thermal Systems, 2021).

Something that is very important to understand is that carryover is measured in percentage. Why is this important? Because when water treaters implement a boiler chemistry program, it is designed to maintain a certain level of ions in the drum water based on steam purity requirements. Therefore, if the drum chemistry should happen to change, say blowdown is not maintained properly and the boiler is overcycled, the percent carryover stays the same, but the absolute ionic concentration increases. This becomes important when troubleshooting since an increase in steam ions may make one think an increase in carryover has occurred; however, if the drum water chemistry has changed, an increase in percent carryover may not be the issue. This also works vice versa in that an increase in carryover may or may not show an increase in steam ions if the drum chemistry is more dilute than normal. More on this to follow in the *Monitoring* section.

CARRYOVER POSSIBLE CAUSES

*Mechanical carryover c*an happen for a variety of reasons, but the most common are poor water level control, poor/no steam separation, exceeding design steam flow rates/circulation ratios, foaming, and priming/pressure swings.

1. *Poor Water Level Control:* Level control in a boiler would seem pretty straightforward, but level can fluctuate as a result of plant demands, operator preferences, and blowdown control schemes. The operating water level is dictated by the manufacturer with carryover in mind, and not always at the drum’s centerline. If the boiler is operated at a level above manufacturers’ specifications, carryover can increase due to the lack of headspace, which allows for steam release.

   Something else to be cognizant of when discussing level control is the feedwater entrance into the drum. There have been times when the incoming feedwater was entering in such a way that it was pushing the water level up in a localized area, resulting in poor steam quality. This is where good, downtime inspections play an important role. In this particular case, operations noticed the uneven level, and tied it to an improperly positioned feedwater nozzle.

2. *Poor/No Steam Separation:* Steam separation equipment is typically in the form of cyclone separators and scrubbers. Cyclone separators take the incoming steam/water mixture from the generating tubes, spin the mixture at a high rate of speed, separating the moisture from the steam and discharging that moisture downward into the bulk water. The steam exits the top of the cyclone separator where it then enters the scrubber section. Scrubbers have a wire-mesh pad on the bottom of chevron plate separators. As the

moisture ladened steam mixture hits the chevron plates, it is sent on a torturous path where the steam passes through and the water forms droplets that, due to their weight and size, cannot pass through the channels and fall back to the bulk water.

There are times when there is degradation of the steam separation equipment, rendering it inadequate for the task. However, there are times when the boiler operation is pushed beyond its design, and the mass/velocity of the steam exceeds the separation equipment's capabilities. Therefore, when troubleshooting, it is important to combine a thorough physical inspection with a detailed review of the plant's operational data.

There are cases where there is no steam separation equipment. For instance, a low-pressure, firetube boiler will not have cyclone separators or scrubbers. These types of boilers rely on a very large surface area to promote good steam release. In these cases, poor level control can be a big influence on carryover.

3. *Exceeding Design Steam Flow Rates/Circulation Ratios:* Like any piece of equipment, boilers are designed within a defined set of parameters and limits. Two parameters that are critical for boiler design are steam flow rate and circulation ratio. *Steam flow rate* is self-explanatory and is the amount of steam generated (usually measured in pounds per hour). As previously discussed, over running a boiler can lead to an increase in mechanical carryover by the mechanism described.

   Circulation ratio on the other hand is not as well understood. Recirculating boilers generate steam by heating water as it recirculates through sets of tubes. Two circuits of particular importance are the risers and downcomers. As the names imply, risers have water that is rising from the muddrum (not all boilers have muddrums) and generating steam on the way up to the steam drum. Downcomers take the drum's bulk water, which has released heat in the form of steam and mixed with cooler makeup water, down to the muddrum. The density difference between the two is what creates the natural circulation in the boiler. As the water is circulating, a small amount is being pulled off as steam and sent to the processes. The amount of water circulated versus the amount of steam generated is what is known as the circulation ratio. The circulation ratio is critical in maintaining the proper heat flux throughout all the boiler's circuits. A deviation from design circulation, i.e., operating the boiler significantly above design loads, can change the circulation ratio, which in turn can lead to an increase in mechanical carryover. Conversely, operating the boiler significantly below design loads can cause poor circulation and increase the potential for steam blanketing of the tubes.

4. *Foaming:* Foaming in a boiler is not typical, and fortunately, is usually easy to troubleshoot. Two common causes for foaming are excess alkalinity and contamination. *Excess alkalinity* usually occurs when a boiler is overcycled and is more of a problem in industrial applications using soft water makeups with elevated alkalinities. Those applications using reverse osmosis (RO) or demineralized (Demin) water don't typically

experience this issue as there is very little if any alkalinity in the effluent of these processes. However, in sodium zeolite softener applications, alkalinity is not removed and thus needs to be accounted for in the boiler chemistry program. Practically speaking, water treaters try to maintain a total alkalinity limit in the boiler at 600 – 700 ppm. This is a general rule of thumb and more specific limits can be found in the ASME guidelines. When alkalinity cycles up in the boiler, it changes the water's surface tension. If too much alkalinity is present, the water can start to form very stable bubbles, which ultimately lead to large amounts of foam being produced. It is important to remember that bubbles are a combination of moisture and vapor (steam in this case). When the low-density bubble enters the steam space, it passes through the separation equipment, contributing a small amount of moisture to the steam. That moisture contains the same ionic constituents as the boiler drum bulk water, hence the increase in steam ions.

Contamination can also cause bulk water foaming. Contaminants like oil, food items, and other organics, break down in the boiler to form acids and lower molecular weight organics. The acids are problematic in that they depress the pH, but the organics cause a change in the water's surface tension just like the alkalinity previously discussed. These organics will also stabilize the bubbles, leading to foaming in the drum. The result is the same, an increase in steam moisture and ionic loading.

It is also possible to cause foaming simply by over cycling the boiler water. Water treatment experts spend a great deal of time developing boiler treatment programs that have specific limits. One of these limits is specific conductivity, which in itself is not the real parameter of concern when it comes to harm to the boiler. Conductivity is used as an online surrogate for the control of the other more harmful ions like hardness, chlorides, and alkalinity. When the target conductivity is exceeded and the TDS in the bulk water increases, the tendency for foaming increases due to TDS's ability to stabilize foam. Under normal conditions, this is not a concern; however, if the boiler cycles of concentration (COCs) are not controlled properly with the appropriate amount blowdown, the boiler can cycle up to unsustainable levels. The excess TDS can impart a change in surface tension, leading to foaming as described in the previous discussion about alkalinity and contamination.

5. *Priming/Pressure Swings:* When plant load and steam demand are variable, target steam quality can be difficult to maintain. *Priming and Pressure Swings* are combined in this section because they can be closely related in practical application. *Priming* is the drawing of boiler water up into the steam header, which can be common in plants that rapidly swing process loads. When this happens, it manifests as an elevated condensate specific conductivity, which is boiler water coming back around in the condensate. *Priming* can also initiate foaming by causing a sudden reduction in boiler pressure, thus causing the formation of steam bubbles in the bulk water (Andrade, Gates, & McCarthy, 1983). Therefore, if foaming is occurring, it is important to understand if it is constant, or cyclical, as the difference will help in determining the corrective actions required.

Pressure Swings can also lead to mechanical carryover because of the change in volume per pound of water/steam. As drum pressure drops, the density of the steam decreases (Figure 1). For instance, the author was involved in a case where a plant dropped drum pressure from 1,500 psi to 900 psi in a matter of seconds without tripping the unit offline. With this change in pressure, a corresponding increase in volume of nearly 43% would be experienced. At a consistent steam flow, with a volume change of this magnitude, the velocity through the steam separation equipment would increase significantly with this increase in volume. While this is an extreme case, many industrial applications experience the same phenomenon when process loads vary.

Vaporous carryover is less complicated when compared to the various phenomena that can cause mechanical carryover. Vaporous carryover occurs when the operating pressure exceeds the point at which an ion goes from being ionized in the bulk water, to a vaporous state in the steam space. Again, silica and copper are the most common ions of concern and is more applicable in higher-pressure applications. Silica starts to enter the vapor phase at somewhere around 900 psi, and copper starts at around 2,400 psi (obviously a very high-pressure application such as utility power generation).

As with mechanical carryover, vaporous carryover is also expressed as a percentage, which increases with increasing pressure. For instance, at a constant pH, the percentage of silica in the vapor phase nearly doubles with an increase in pressure from 1,800 to 2,200 psi. Conversely, at constant bulk water concentrations, an increase in pH reduces the percentage of silica in the vapor phase. Therefore, the key to maintaining the appropriate ionic concentrations in the steam is maintaining the proper boiler bulk water concentrations. But keep in mind, the volatility of certain ions can also be affected by the bulk water pH, which needs to be balanced with the overall needs of the chemistry program.

CARRYOVER IMPLICATIONS

Mechanical and *vaporous* carryover can have significant, adverse effects on the overall plant operation. Ionic carryover, both mechanical and vaporous, can cause deposition on important equipment such as superheaters, steam piping, valving, and steam turbines, resulting in failures and downtime. Unfortunately, these failures can be expensive and time-consuming, not to mention the loss of production revenue. Chloride, sulfates, and caustics carrying into the steam can cause corrosion of equipment, and like deposition, and even more so, corrosion can lead to very costly and time-consuming failures.

CARRYOVER INDICATIONS

Aside from online instrumentation and field testing, which is discussed in the next section, what are some ways to determine that carryover is taking place? Some qualitative indicators may include the following:

1. *Water hammering in the steam system* – can be an indication of boiler water carryover as slugs of boiler water travel down the steam piping at the higher steam velocities, impacting equipment downstream causing water hammer. Also, as the boiler water

travels down the steam piping, it cools due to radiant heat losses. When it contacts a pocket of steam, it causes a rapid, violent collapse, manifesting as water hammer.

2. *Bubbles in the sight glass* – can indicate foaming in the drum. This seems to be more common on the larger package boilers, but regardless of boiler type, check the sight glass if foaming is suspected.
3. *Water level inspection during outages/turnarounds* – can be a great way to determine normal operating level, as well as level fluctuations. There are times that one will find the level higher at one end of the boiler relative to the other. A higher level can lead to an increase in boiler water carryover percentage. An uneven boiler water level, or an overall elevated water level, can indicate a boiler design or operational issue that needs further investigation.
4. *Repeat failures* of steam equipment such as superheaters, valving, and receivers. As the boiler water carries over, deposition and corrosion can occur in downstream equipment resulting in repetitive failures.

CARRYOVER MONITORING

This is where most plants are lacking. Many industrial applications lack the necessary online instrumentation to monitor for boiler water carryover. Power plants tend to be very good at this, spending millions of dollars on instrumentation panels, sample points, sample coolers, probes, and data capture software. In the industrial world however, there are many plants that have no online instrumentation, and rely strictly on manual, field testing.

There is no substitute for continuous, online monitoring. When data is captured continuously, the ability to identify, troubleshoot, and correct potential issues is improved exponentially. Yes, the equipment requires upfront capital and manhours to maintain, but this cost is negligible when compared to equipment damage and lost revenue. Furthermore, the key instrumentation necessary for effective monitoring is a lot less than most would think. The following is the recommended online instrumentation for steam:

1. *Steam Sodium* is used to monitor for boiler mechanical carryover. Sodium is typically the most prolific ion in boiler water, making it a good ion for monitoring. Sodium analyzers have been used for decades, and their accuracy and reliability have long been proven.
2. *Boiler Water Sodium* is used as part of the calculation to determine the percent carryover of boiler water. Coupled with the steam sodium, one can calculate the percentage of water carryover without having to use a calorimeter.
3. *Steam Silica* is another good ion to monitor alongside sodium. For pressures less than 900 psi, the sodium and silica ratios in the steam can be compared to the boiler water ratios, further improving troubleshooting capabilities. For pressures greater than 900 psi, this instrumentation is necessary to monitor for both vaporous and mechanical carryover. For instance, if operating at 1,800 psi one sees a 3% carryover in silica but only 0.2% in sodium, they can conclude the steam silica is predominately from vaporous carryover.
4. *Boiler Water Silica*, like boiler water sodium, is used in conjunction with the steam results to improve monitoring capabilities.
5. *Steam Specific Conductivity* is a less expensive way to monitor for mechanical carryover, as long as one takes into consideration the conductivity contribution from the volatile

amine program. A spike in specific conductivity can be an indication of boiler water carry over, especially with further confirmation from a sodium or silica analyzer.

6. *Boiler Water Specific Conductivity* is typically already installed as it is used to control operating COCs.
7. *Steam/Condensate pH* can also be a good, inexpensive way to monitor for carryover. Neutralizing amines are typically fed to maintain a condensate pH of 8.5 – 9.2 in lower-pressure, industrial applications, and 9.4 – 9.8 in all-steel, heavy industry applications. For the lower-pressure systems, the boiler water pH is normally greater than 10.0. Therefore, if the steam pH analyzer registers 10.0 or greater, it can be a good sign carryover is occurring. Couple this with the other analyzers listed, and a good picture starts to get painted.

This list is not exhaustive, but it provides the basics of what is necessary for monitoring for boiler water carryover. It is important to note that these analyzers should be installed on the boiler drum skimmer blowdown for drum samples, and on the saturated steam header for the steam sampling. Do not install this equipment on the superheat steam sample. In this discussion, they are being used to monitor for boiler water carryover. If they are installed on the superheat sample it will not be representative of the saturated steam sample, which is directly off the drum, since some of the carried over ions can and will precipitate on the superheater sections. Also, if steam attemperation/desuperheating is used, the superheat sample is a combination of the attemperation water and the saturated steam. Therefore, contaminated attemperation water will give a false indication of boiler carryover. Yes, there are cases where instruments are installed on the superheat steam sample, but that is not for boiler water carryover detection, that is to monitor final steam to the equipment. In power plants for instance, they typically have both for that very reason.

POSSIBLE CORRECTIVE ACTION FOR CARRYOVER

How to correct for carryover depends on the type of carryover being experienced. For *vaporous carryover*, it is more about ensuring the bulk water ionic concentrations are appropriate for the operating pressure. For instance, if a plant is operating at 2,200 psi, they may choose to limit the drum silica levels to 150 ppb, while one operating at 1,200 psi may choose 800 ppb. These are not real limits, just an example of correlating the limits with the operating pressure. These limits can, and should, be adjusted based on the results of the online instrumentation and field testing.

Correcting for *mechanical carryover* is a bit different since there are so many possible causes. After determining the cause of the carryover, the following may be some potential corrective actions to take:

1. *Poor level control* can be corrected by adjusting the operating level to one that promotes the highest *quality* steam. Consulting with the manufacturer, downtime inspections, and online instrumentation can all be part of the optimization program to minimize carryover due to level control. Also, as previously discussed, make sure that the feedwater is not entering in such a way as to disturb the water level.
2. *Poor steam separation* can be corrected mechanically if it is found the equipment requires maintenance. This of course assumes the equipment was designed properly and the boiler is being operated per specification. In many cases, replacing scrubber mesh is

all that is required. This is not to say more extensive repairs may not be necessary, but experience has shown this to be a common occurrence.

3. *Exceeding design flow rates/circulation ratios* tends to be more of a design/operational issue. Unfortunately, from a practical application perspective, if carryover is due to these phenomena, a change in operation or boiler design is necessary.
4. *Foaming* is one of those occurrences that is commonly attributed to a water chemistry issue. If the foaming is a result of excess alkalinity, the plant can either reduce the COCs to lower the bulk water alkalinity concentrations, or they can remove the alkalinity in the makeup water with an RO or a dealkalizer. Obviously, one is easier and a lot less expensive than the other, but in the long run, the capital project may have the better return on investment (ROI). If the foaming is due to a contamination event, then it becomes a question of whether it is an acute or chronic issue. If it is acute, it is best to drain and clean the boiler and then bring it back online. If it is chronic, then removing the contaminant prior to the feedwater entering the boiler can be the best option. This may also require a capital project, but again, fixing problems mechanically is usually less expensive in the long run than a perpetual chemical fix. Antifoam can be used as a temporary solution until the contamination can be removed, but it is important to understand that more antifoam is not always better. There is a delicate balance with antifoam chemistries, and one needs to be careful not to overfeed these chemicals.
5. *Priming and pressure swings* are usually addressed with operational corrections. If a plant can either maintain a steady load or reduce the amplitude of the load swings, priming and pressure swings are rarely an issue. If load swings are something that just can’t be avoided, valve control and/or surge vessels may be an appropriate solution.

CARRYUNDER PRIMER

While carryover is the drawing up of boiler water into the steam header, carryunder is the drawing down of live steam into the boiler water, also referred to as steam entrainment. Carryunder does not appear to occur as frequently as carryover; however, when it occurs, it can have significant, adverse effects on the boiler equipment, specifically the boiler tubes and muddrum.

Recall, boilers operate with a natural circulation due to the density difference between the water-containing downcomers and the water/steam-containing risers. As the water/steam mixture enters the boiler drum, it is separated via the steam separation equipment, which is designed to ensure the steam enters the steam header and the water stays behind in steam drum (The Babcock and Wilcox Company - a MCDermott Company, 2005). The drum bulk water is then mixed with the cooler incoming feedwater, causing subcooling and an increase in density. The denser water falls down the downcomer into the muddrum, where the process starts again. This is if everything goes well. When everything does not go well, steam ends up in the downcomers and muddrum.

CARRYUNDER POSSIBLE CAUSES

This paper discusses several causes that can lead to steam entrainment and carryunder: poor steam separation, elevated feedwater temperature, poor boiler water level control, and poor circulation causing risers to become downcomers.

1. *Poor separation* occurs when steam is not fully removed from the risers' steam/water mixture entering the steam separation equipment. The partial removal causes steam to become entrained in the bulk water. The bulk water density is then reduced with the presence of live steam, especially when compared with its density if full subcooling is achieved (Gardner, BsSc, Crow, B Eng, PhD, & Neller, B Sc, 1973).
2. *Elevated feedwater temperature* can occur if a plant replaces an economizer with a larger unit, or if a plant pushes the saturation pressure of a deaerator (DA) beyond design (Banweg, 2013). Both actions lead to an increase in temperature of the feedwater entering the boiler. A feedwater temperature above design can reduce the density difference between the risers and downcomers, which in turn changes the circulation ratio and increases the chance of steam entrainment. This is why economizers are designed with a specific approach temperature (the difference between the boiler drum bulk water and the exit of the economizer) to minimize the potential for circulation issues.
3. *Poor boiler water level control* can affect the rate of carryunder, just as it did for carryover. However, instead of a high level being the problem, a low level is what imparts carryunder. Gardner et al confirmed through experimentation that there is a direct correlation between a liquid pool level and the amount of carryunder that occurs; with a lower level causing a higher rate of carryunder and a higher level leading to a lower rate of carryunder (Gardner, BsSc, Crow, B Eng, PhD, & Neller, B Sc, 1973).
4. *Risers becoming downcomers* can occur due to the increase in feedwater temperature as discussed, but it can also happen if there is a change in heat flux in the firebox. If there is any fireside deposition, it can modify the heat transfer rate from design, which can affect the overall circulation of the boiler. The key point to takeaway here is carryunder ultimately leads to entrainment of steam in the bulk water, which in turn leads to steam in the downcomers and muddrums.

CARRYUNDER IMPLICATIONS

Much like carryover, the result of carryunder is deposition and corrosion. Because steam is less dense than water, once in a tube or drum, it will cause steam blanketing if there is no way for it to escape. This can happen anywhere in the system but is most prominent in horizontal sections of the boiler such as horizontal tubes and in the tops of muddrums; this is especially true of low-flow areas. For those tubes that can't seem to figure out whether they are risers or downcomers, stagnation can occur, which leads to steam blanketing of vertically oriented tubes (Banweg, 2013).

The steam blanketing causes a steam/water interface where solids may concentrate to levels that are aggressive to the boiler metallurgy. Under normal conditions, the bulk water pH in an industrial boiler is somewhere between 9.5 – 11.0. At these levels, the water is not aggressive, and in fact is passive, thus the point of the chemical program. Furthermore, TDS levels are maintained to a level at which deposition is controllable and corrosion is not a concern. But when there is a small (relative to the rest of the system), stagnant area of steam blanketing, solids may accumulate to unsafe levels causing deposition and corrosion, specifically aggressive under-deposition corrosion. It is not unusual to see tube failures due to this phenomenon. In some drastic cases, drum failure has also occurred.

CARRYUNDER MONITORING AND INDICATIONS

Carryunder and steam blanketing can be seen during tube inspections, but it has been the author's experience that aggressive carryunder seems to be most evident when inspecting muddrums, particularly those with protruding tubes. As Figure 2 shows, many boilers have flush, rolled tubes in the steam drum, but protruding, flared tubes in the muddrum. This is where the problem starts. As the entrained steam travels from the downcomers to the muddrum, it gets trapped in the roof of the muddrum because the protruding tubes do not allow for the escape of the steam pocket. As the photo shows, the area where the pocket of steam resided during operation is clearly visible by the solids deposit outline.

Unfortunately, there is no method for monitoring for this phenomenon while the boiler is in operation. The best method for monitoring occurrence and severity is a protocol of frequent inspections. When carryunder is occurring, it is not a mystery and the signs are clearly visible, as long as one knows what they are seeing.

POSSIBLE CORRECTIVE ACTIONS FOR CARRYUNDER

Correcting for carryunder may require mechanical modifications that will require consultation with the boiler manufacturer. Some areas of consideration are:

1. If the carryunder is due to a *heat flux* issue, modifications to the risers, downcomers, and/or screen tubes may be necessary. Prior to any modifications, make sure the fireside of the tubes is clean and free from debris or obstructions, which may cause a change in localized heat flux.
2. If the carryunder is due to an *increase in feedwater temperature*, it may require revisiting any recent modifications such as economizer swap outs or changes in the DA operation. If any modifications changed the economizer outlet temperature, they could be the root cause for the increase in carryunder occurrence as per the previous discussion.
3. If the carryunder is causing *steam blanketing in the muddrum*, some plants have chosen to make notches in the protruding tubes to allow for the movement of steam from the roof of the drum to the risers. The author does not have any quantitative data to determine if these notches improved the steam blanketing, but inspections suggest it has not worsened. It is imperative that anyone attempting to make this modification consult with the boiler manufacturer.

   There are cases where there are no tubes located near the steam blanketing (Figure 3). In these cases, the corrective action would have to be design, and possibly operational, in nature. It is possible that removing the cause of the entrainment, such as better steam separation, could be the action taken, but that assumes it is a steam separation issue.

CONCLUSION

Boiler carryover and carryunder are two phenomena that are common throughout many industrial applications. Understanding the root causes is important when developing programs for monitoring and correcting. Unfortunately, several of the causes for both are design in nature, and thus require time and capital projects to correct. It is important to start with the boiler manufacturer before any modifications are made, operationally or mechanically.

Figures

Figure 1: Density of Water and Steam at Various Pressures (Source: Kevin Boudreaux)

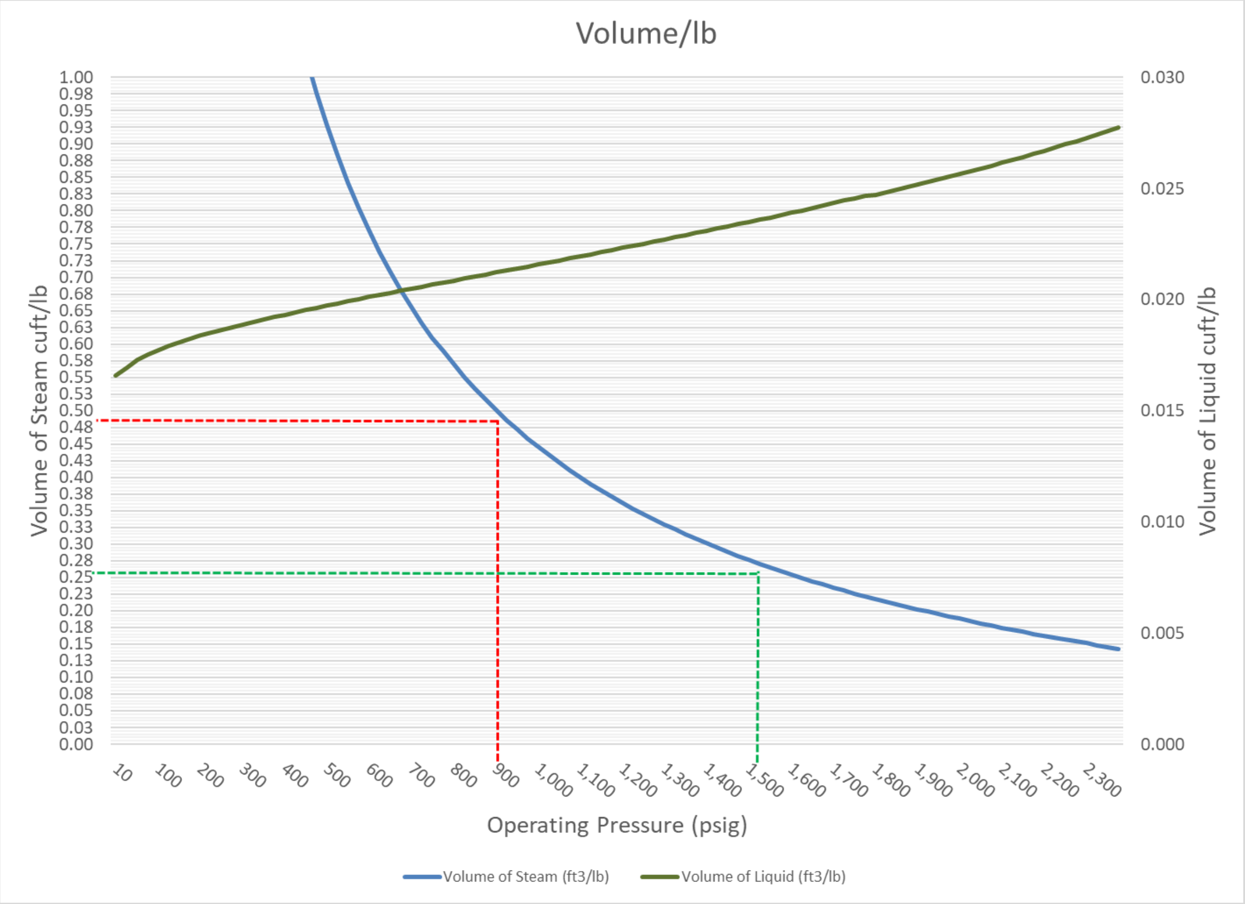

Figure 2 Muddrum showing protruding tubes. (Courtesy Gary Bonafilia – Williams College)

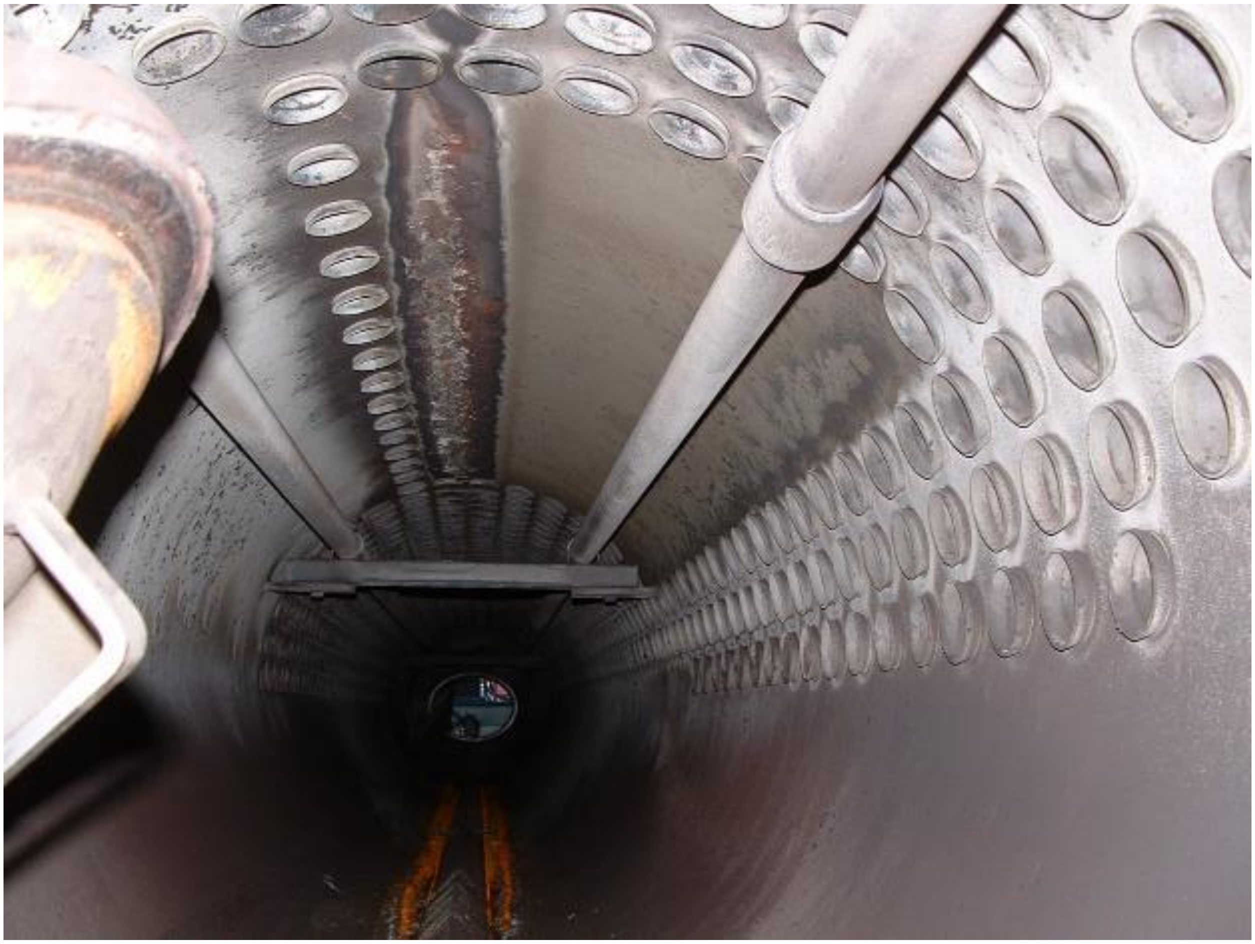

Figure 3: Boiler muddrum with carryunder, but no tubes present near steam blanketing.

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