BOILER WATER TREATMENT AND RELATED COSTS OF BOILER OPERATION: AN EVALUATION OF BOILERS IN THE LOUISIANA SUGAR INDUSTRY

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ABSTRACT

If one considers the importance that steam plays in the production of sugar, the boilers should be considered one of the highest priorities in a sugar factory. In fact, some have said that a sugar factory boiler is the heart of the factory. But, do sugar factory personnel place a high priority on the condition of the boiler? To answer this question, a study was conducted on 43 sugar factory boilers in Louisiana at the end of the 2003 crop. Video borescope equipment was used to examine the internal condition of 222 different tubes and to document their condition. Additional data from analyzing boiler water and feedwater during the crop was evaluated to show the impact of boiler conditions and operating practices on the operating efficiencies of the factories. Based on the severity of conditions found, in terms of deposition and scaling, calculations were made to demonstrate how this impacts factory profits when supplemental fuels are required to achieve firing rates required for efficient factory operation. A discussion of how these adverse conditions occur and why the water treatment program is of utmost importance is also presented.

INTRODUCTION

The 2003 grinding season in Louisiana was marked by near perfect harvesting conditions, low yields, and high sugar content in cane. This led to a short but productive crop with Factory GTE (Grinding Time Efficiencies) approaching historic levels.

Normally this would equate to continuous grinding conditions, relatively few factory upsets, and a continuous source of pure condensate for the boilers. But, during the crop, periodic sampling of the boiler water from various Louisiana factories indicated problems with addition of hard water, sugar contamination, and boiler water chemistry upsets.

During the repair season, eight factories (43 boilers total) were examined with a video borescope. Any single inspection could be considered an anomaly, but when analyzed, the video borescope data indicated that a trend of corrosion and scaling was taking place in a majority of the boilers.

With the price of alternative fuels and steel increasing, it is important to review operations to insure that the boilers are providing maximum heat transfer and that boiler cleanliness is being achieved.

MATERIALS AND METHODS

The boilers examined were of all types and configurations. The borescope inspections were done from the top steam drums running the optical fiber down the tubes. After reviewing the results on video tape, observations were recorded on a chart (Table 1). The observation categories are as follows:

Recorded Observation	Description
• Clean Tube	Basically clean metal
• Slightly Scaled	Orange peel (bare metal and some spotty scale)
• Moderately Scaled	1/32" Scale (continuous)
• Heavily Scaled	1/16" + Scale (continuous)
• Chipped Scale	Scale that is flaking and easily removed
• Pitting Corrosion	Localized rust, generally oxygen pitting
• Under Deposit Corrosion	Corrosion occurring under the scale

The borescope videotape was reviewed by management personnel at each factory, and the findings recorded on the borescope observation chart were validated by those individuals.

Table 1 is a sample of the observations recorded at one factory. It demonstrates that more then one adverse condition can occur at the same time. For example, this inspection showed that some boilers have experienced scaling and under deposit corrosion at the same time.

Note that not a single tube examined in any one of the five boilers at this factory was free from scale. Also, while pitting corrosion was not observed in any of the examined tubes, heavy scaling and under deposit corrosion were the predominant findings of these boiler inspections, and the conditions were not restricted to any isolated part of the boiler. An "X" in a column of the chart indicates that condition was observed and recorded with the video borescope.

Table 1. Borescope observation chart: An example from one factory.

Boiler	Clean tube	Slightly scaled	Moderate scaled 1/32"	Heavily scaled 1/16" +	Chipped scale	Pitting corrosion
Boiler A						
Center tube				X	Iron oxide	
Downcomer			X			
Riser				X		
Center tube				X		
Riser				X		
Downcomer				X		
Boiler B						
Center tube			X			
Downcomer			X			
Riser				X		
Center tube			X			
Riser				X		
Downcomer			X			
Boiler C						
Center tube				X		
Downcomer		X				
Riser				X		
Center tube				X	X	
Riser				X	X	
Downcomer				X	X	
Boiler D						
Center tube		X				
Downcomer			X			
Riser		X				
Center tube						
Riser						
Downcomer						
Boiler E						
Center tube				X	X	
Downcomer			X			
Riser			X			
Center tube				X	X	
Riser				X	X	
Downcomer				X	X	

A borescope observation chart was prepared from data observed at each of the eight Louisiana factories. In all, a total of 43 boilers were inspected at the end of the 2003 crop. A summary of all observations recorded from the 43 boilers is shown in Table 2.

This summary reveals that two thirds of the tubes inspected have scale with a thickness of 1/32" or greater, and one half of the tubes exhibited some type of corrosion. Deposit thickness was estimated during video borescope visual observation using previous experience. Nearly one quarter of all tubes inspected had only a slight amount of scale and only about ten percent of the tubes inspected were found to be clean and free from corrosion.

Table 2. Factory borescope summary for eight factories with 222 tubes[1] examined in 43 boilers.

Factory	Clean Tube	Slightly Scaled	Moderately Scaled 1/32"	Heavily Scaled 1/16"+	Chipped Scaling	Pitting Corrosion	Under Deposit Corrosion
A	3	4	10		2	1	3
B	6	10	12	9	3	7	7
C		3	8	16	7		15
D	3	15	1			2	3
E	1	1		18	3	1	1
F		5	12	19	2	26	4
G	2	1	7	25	7	11	20
H	9	12	5	5		6	5
Total	24	51	55	92	24	54	58
Average	10.8%	23.0%	24.8%	41.4%	10.8%	24.3%	26.1%

[1] Any given tube could have more than one condition observed.

RESULTS AND DISCUSSION

Deposit and Scale Formation Mechanisms

Deposition and scale formation in steam generating systems results from the fact that the solubility of the deposit forming salts decreases with increasing temperature and concentration. Some of the more common constituents associated with deposition and scaling are:

Calcium (Ca)	Phosphate (PO_4)
Magnesium (Mg)	Sulfate (SO_4)
Bicarbonate (HCO_3)	Silicate (SiO_2)
Carbonate (CO_3)	Iron (Fe)

Without proper treatment of feedwater and boiler water, deposits and scale may form by one or a combination of the following mechanisms:

1. **Precipitation of relatively insoluble feedwater hardness compounds either in the preboiler and/or the boiler.** Hardness should be controlled in the feedwater prior to reaching the boiler and precipitated in the main body of boiler water in the steam and mud drums. Precipitation of solids will form hard deposits on heat transfer if allowed to adhere to these surfaces.

2. **Improper selection or inadequate control of chemical sludge conditioners and dispersants.** Chemical treatments utilize various mechanisms to condition and disperse precipitates and suspended solids formed in boiler water. Using too little of the proper treatment chemical may not provide adequate conditioning and dispersion to prevent adherence to boiler metal, and over-feeding the chemical treatment may interfere with proper conditioning of suspended solids and prevent their removal from the boiler through blowdown. Any one of these conditions can lead to increased boiler deposition tendencies.

3. **Supersaturation and crystallization of relatively soluble dissolved solids at the heat transfer surfaces.** The thin film of boiler water immediately adjacent to the primary heating surface tends to become more concentrated with dissolved solids than the main body of boiler water. As steam bubbles are formed, they depart from the tube wall leaving solids behind which form deposits.
4. **Increasing the concentration of suspended solids in the boiler water due to inadequate blowdown.** Failure to properly perform blowdown results in more solids in contact with the heat transfer surfaces increasing the potential for scale formation and carryover.
5. **Accumulation of iron and copper oxides from corrosion by-products entering the boiler from the preboiler system or transported with the return condensate.** These metal oxides not only form deposits, but they also may act as binders for other insoluble solids in the boiler water, further increasing deposit tendencies. In addition, they can contribute to electrolysis corrosion.
6. **Oil or process contamination can adhere to boiler surfaces or increase adherence of boiler solids.** Condenser leakage will contaminate condensate with hard water and chemical treatment chemicals, such as corrosion inhibitors, anti-foulants and biocides, all of which can lead to boiler deposit formation.

Mechanical Operation Factors that Influence Deposit Tendencies

Improper burner alignment can produce high temperature areas on boiler tubes. Localized high heat flux can cause hot spots and overheating of tubes leading to increased concentration of boiler water impurities resulting in increased boiler deposits and failed tubes.

The mode of boiler operation may be a cause of increased deposit formation. Operating boilers above their rated capacity may cause high metal temperatures. Operation at low loads or intermittent operation can affect water circulation. Since water circulation in a boiler is important to cleanliness and cooling of hot tube surfaces, changes in circulation greatly affect deposit tendencies.

Effects of Deposit and Scale Formation

Deposits in the pre-boiler section can restrict water flow to the boiler, cause feedwater regulating valves to malfunction, decrease heat transfer in stage heaters and economizers, and contribute to under deposit localized corrosion.

Deposits in boiler tubes can reduce circulation through tubes. This may enhance further deposit formation due to the reduction of the cleansing effect of circulating water on solids concentrating at heat transfer surfaces. Since deposits are poor conductors of heat, they retard heat transfer from combustion gases.

As heat transfer is further retarded, boiler tube metal temperatures increase. The approximate softening temperature of boiler tube metal is about 482.2 °C (900 ^{0}F). If heat retardation of boiler deposits causes this temperature to be reached, tube softening and rupture will occur. However, even when deposit build-up may not be sufficient to cause tube failure, their insulating effect may still result in reduced boiler operation efficiency and energy wastage by allowing excessive heat to exit the boiler with the stack gas.

As discussed earlier, deposits may also lead to differential corrosion cells beneath their surfaces. The result is localized corrosion or pitting. If such corrosion is severe, boiler metal can become thinned and weakened, resulting in ruptures due to internal boiler pressure.

Direct Costs of Scale and Corrosion in a Boiler

Scale creates a thermal transfer barrier which in turn requires more fuel to achieve the same heat transfer. Listed below in Table 3 are the potential costs incurred if an alternative fuel must be used to replace the heat value depletion due to excessive scaling.

Table 3. Fuel costs due to scaling in a factory grinding 10,000 tons of cane per day. Where bagasse used is 3,300 tons per day, 2.2 barrels fuel oil = 1 mt bagasse, 13,200 ft^3 natural gas = 1 mt bagasse, and bwt = bagasse weight.

Scale thickness	% Fuel wasted[1]	Tons bagasse wasted (at 50% moisture)	Fuel oil cost ($38 x 2.2 x bwt) [1]	Natural gas cost ($6 x 13.2 x bwt) [1]
1/32"	7%	231	$19,312	$18,295
1/25"	9%	297	$24,829	$23,522
1/20"	11%	363	$30,347	$28,750
1/16"	13%	429	$35,864	$33,977
1/11"	15%	495	$41,382	$39,204
1/9"	16%	528	$44,141	$41,818

[1] Chen and Chou, 1993.

There is a basic argument that in a sugar factory the bagasse fuel is a “free” resource so there can be no cost assigned to it. But, let us review bagasse usage in Louisiana.

1. Louisiana has historically preferred to burn low cost natural gas. Therefore, the practice and techniques involved in burning bagasse are not as refined in Louisiana as in the rest of the world.
2. Normally, 10-15% excess bagasse should be produced during grinding. Due to inefficient steam balances, such bagasse surpluses are not realized.
3. The crop in Louisiana is mechanically harvested under less than optimum conditions. The mud and trash that is brought in with the cane tends to reduce its Btu value resulting in more bagasse being needed to obtain equivalent firing rates (Btu values). Therefore less surplus bagasse is available in these factories.
4. Excess bagasse that is normally available is generally not stored in a manner that it can be easily reclaimed. This means that alternative fuels must be used to continue production.
5. Weather has periodically caused major problems with the quality of bagasse leading to

almost continual use of alternative fuels to maintain the ignition of the bagasse.

It is generally known that Louisiana factories incur costs for alternative fuels in amounts that have exceeded $1,000,000 for a single crop.

Referring to Table 3, if a factory has 1/16" of scale on the boiler tubes, over 400 tons of additional bagasse is needed to operate a factory grinding 10,000 tons cane per day. Because of the excess bagasse accumulated during the daily grinding, bagasse is available during time of mill stoppages. But, history tells us that at some time during the crop, poor quality bagasse, extensive down times, or perhaps slowdowns due to routine maintenance cause a shortage of bagasse. During these times, the factory should have available adequate supplies of dry, clean bagasse to use as a fuel source. However, due to the presence of scale in the boiler, the 400 tons additional bagasse needed is not available. Supplemental fuels are now required and are direct costs of doing business. This cost comes directly off the factory's bottom line, that is, a direct reduction of profits. Reduction of efficiency always translates into loss of money.

Indirect Costs of Scale and Corrosion in a Boiler

Indirect costs are those items or events that are generally not immediately recognized or do not have an immediate impact on factory operation. The exception to this may be a severe boiler tube failure leading to a shutdown. In general, the major indirect costs are categorized as:

- Production downtime due to boiler tube failures
- Excess chemical usage
- Manual cleaning of the tubes during repair season
- Acid cleaning of the boiler tubes
- Replacement of the boiler tubes

Boiler inspections at the end of the grinding season can be quite revealing. Aside from the general observations and specifically video borescoping tubes, analyses of deposition in the boilers can identify numerous operating conditions leading up to the conditions that caused the deposit to form in the boiler.

Table 4 shows a comparison of two analyses of tube deposits collected from a boiler. The identification of the constituents and their relative concentrations (as % of the total deposit) can be used to draw conclusions as to why they formed. If complete operating records and logs of boiler water, feedwater, and condensate analyses were kept, all of this information may be compared and used to identify and summarize the problems encountered. The analyses of the boiler tube deposits (scale) in Table 4 demonstrate that several detrimental conditions occurred within the boiler at various times during its operation:

Table 4. Boiler tube deposit analyses.

Constituent	% Dry Weight Tube #1	 Tube #2
Calcium Phosphate	10.7	15.0
Calcium Carbonate	5.0	0.0
Iron Oxide	65.0	51.8
Copper II Oxide	10.0	11.2
Magnesium Hydroxide	5.8	7.2
Magnetic	Yes	Yes

The conditions noted above indicate the following conditions occurred during the operation of the sampled boiler:

1. Hardness intrusion into the boiler.
2. Loss of phosphate treatment levels in the boiler water.
3. Low alkalinity levels in the boiler; low hydrate (OH) alkalinity.
4. Possible overfeed of phosphate chemical treatment in the presence of calcium.
5. Poor sludge conditioning.
6. Inadequate boiler blowdown.
7. Corrosion in the preboiler or condensate system.
8. Possible corrosion within the boiler itself.

Methods of Deposit / Scale Prevention

The methods of preventing the formation of deposits and scale in steam generating systems are generally a combination of the following:

1. External treatment (pre-treatment) of makeup water to reduce the levels of deposit and scale forming constituents.
2. Internal treatment (chemical addition to feedwater and/or boiler water) to cause precipitation and conditioning of deposit and scale forming constituents to form a fluid, non-adherent sludge, to keep it dispersed, or to form water soluble complexes which remain in solution.
3. Blowdown of boiler water to maintain specified levels of dissolved and suspended solids and to remove sludge accumulations.
4. Close attention to chemical residual levels and the use of proper analytical procedures.
5. Advances in polymer technology allowing for online removal and prevention of deposits.
6. Installation of evaporator condensate dump valves to eliminate sugar contamination and hardness intrusion.

Methods of Corrosion Prevention

Corrosion is rarely completely prevented in a steam generating system. Treatment programs and chemical controls are established to maintain corrosion within acceptable limits. The primary methods of corrosion prevention in steam generating systems are:

1. Close attention to chemical residual levels and the use of proper analytical procedures.
2. Addition of an alkali, such as caustic, to control pH/alkalinity of makeup water, feedwater, and boiler water within specific ranges, particularly during periods of sugar contamination.
3. Removal of dissolved gases by mechanical deaeration and chemical oxygen scavenger addition.
4. Use of oxygen scavengers which promote the formation of the protective magnetite films.
5. Neutralization of carbon dioxide and other acidic gases with neutralizing amines.
6. Use of filming amines, where applicable, to form a protective film on the metal surfaces of steam condensate systems.

Carryover of Boiler Water

Carryover is a general term used to describe moisture and entrained boiler water solids which pass over with the steam from the boiler to turbines and process systems. Foaming and priming in the boiler steam drum are causes of carryover.

Foaming is the formation of small, stable bubbles on the steam release surface. This may be due to excessive levels of dissolved and suspended solids in the boiler water, high alkalinities and oil, process or sugar and other organic contamination.

Priming is the mechanical lifting or surging of boiler water into the steam outlet. While foaming is related to levels of chemical constituents or process contaminants in the boiler water, priming occurs as a result of mechanical and/or operating factors. Defective steam separation equipment, high water levels in the steam drum, boiler operation above its rated capacity, and sudden increases in boiler load are causes of priming.

A special case of boiler carryover not included in either foaming or priming is silica volatilization which occurs as pressure (temperature) of the boiler increases above 600 psig, resulting in selective vapor carryover of silica with the steam.

Problems resulting from carryover of entrained or vaporous boiler water solids include:

1. Low Btu value steam, in essence, wet steam.
2. Superheater deposits and failures.
3. Turbine blade deposits and losses in efficiency.
4. Process contamination.
5. Corrosion/erosion of valves, steam traps, turbine parts and other steam-using equipment.

Methods of Carryover Prevention

Methods used to prevent carryover include:

1. Control of boiler water level and load swings.
2. Control of steaming load within rated capacities.
3. Proper firing distribution.
4. Installation and maintenance of steam separation equipment.
5. Control of boiler water dissolved and suspended solids by blowdown.
6. Control of boiler water chemistry.
7. Elimination of oil, process or other organic contamination.
8. Addition of chemical antifoams.

Sugar Contamination of Boiler Water

When sugar enters the condensate system and returns to the boiler, it depresses the pH of the boiler water to levels that can cause corrosion within the system. High concentrations of sugar and other dissolved solids entering the boiler can be laid down as scale or caramelized on the tubes.

Generally, when this happens, caustic is added to the boiler in order to bring the pH back up to acceptable levels. But by doing so, the TDS levels are raised, and these added solids can contribute to deposition on the tubes. To prevent this, the boiler must be blown down more often, creating a need for more make-up water, which increases the requirement for and resulting cost of water and fuel. Furthermore, additional chemicals must be added to the boiler feedwater system to maintain adequate levels of the scale/corrosion inhibitors and dispersant polymers in the boiler.

A Comprehensive Boiler Water Treatment Program

Controlling boiler water chemistry is the means used to conserve water, prevent scaling and corrosion, and to effectively conserve energy. It is based on the premise that water at a given temperature (with the addition of scale and corrosion inhibitors) can maintain in suspension a certain proportion of solids without depositing them as scale. The higher the concentrations or cycles a boiler can carry, the less makeup water is needed. Fuel is conserved as less cold makeup water is required at higher cycles of concentration.

Table 5 shows a portion of a typical boiler water analysis from a Louisiana factory. Sugar factories inherently possess the best form of feedwater; steam condensate. In this example, the feedwater shows zero hardness, low iron and copper; basically it is excellent feedwater.

Table 5. Boiler water analyses.

SAMPLE	pH	P Alkalinity	M Alkalinity	OH Alkalinity	Chloride	Total Hardness	Calcium Hardness	Fe Iron	Cu Copper	mmhos	Sulfite	Phosphate
Feedwater	12.4	60	64	56	20	0		0.14	0.02	280	2.5	0
Boiler #G	12.7	76	136	16	56	28		3.33	0.07	2600	12.5	0.1
Boiler #A	12.1	28	60	4	16	84		4	1.94	1200	5	7.9
Boiler #B	12.6	80	124	36	40	92		4.1	2.25	2800	15	0
Boiler #C	12.4	60	115	5	24	28		4.2	4.6	2300	12.5	0
Boiler #D	11.8	20	28	12	16	20		3.56	4.63	660	5	0.6
Boiler #E	11.9	24	40	8	8	68		3.06	0.77	800	5	1.9
Boiler #F	12.5	64	76	52	16	80		4.21	2.34	2200	2.5	0.1
				Control Ranges								
Miminum	9.5			150						2000	20	20
Maximum	11.5		700	300		0	0	0.1	0.05	3000	40	40

Upon further review of the boiler water analyses, one finds the following inconsistencies:

1. Low alkalinity, which indicates that sugar has likely contaminated the feedwater at some point in time. This generally lowers the pH with the potential for causing corrosion within the boiler.
2. The boiler water pH is high, which indicates that the operators have identified the sugar contamination and have taken corrective action by adding caustic and antifoam to the boiler feedwater. Although increasing in conductivity, the chlorides indicate very little cycling of the boiler water. Therefore, higher demand for feedwater and consequently more makeup results in higher demand for fuel.
3. High levels of iron and copper indicate corrosion is taking place or that sugar intrusion has carried iron in from the condensate system which could be deposited as iron scale.
4. Phosphate residuals (normally 20-40 mg/L) are being consumed by the additional hardness and iron in the water. Therefore the chemical treatment falls short of its design characteristics.
5. Maintaining proper boiler water chemistry requires continuous operator control. The lack of conductivity control of the boiler water (i.e. maintaining conductivity ranging from 660-2800 µSiemens/cm) creates inconsistencies in control parameters.

It must be noted here that boiler water control in a sugar factory can be, at best, difficult due to the constantly changing operational conditions of the milling operation. But, at the same time, it must be recognized that boiler water chemistry can be controlled within desired control ranges most of the time. This can be achieved with dedicated and properly trained operators supported by a knowledgeable water treatment supplier.

Proper boiler blowdown consists of regular bottom blowdown and continuous blowdown from the steam drum surface. Manual blowdown of the mud drums is essential to remove precipitated solids and to prevent them from contributing to recirculating suspended solids.

A continuous blowdown system effectively removes water from the boiler on a continuous basis under controlled conditions. Water is removed from the boiler at the point of the highest dissolved solids concentration in the boiler water so that maximum dissolved solids may be removed with minimal loss of water and heat from the boiler. Any possible reduction in the amount of blowdown contributes to water and fuel savings (see example in Table 6) as well as keeping the water treatment chemical residuals within their desired control ranges.

Table 6. Makeup water and fuel cost savings resulting from increased operating cycles assuming 1500 HP boiler; 150 psig; 85% return condensate; \$2.35/1000 gal water; \$6.00/ 1000 ft^3 gas.

Cycles	Evaporation gal/hr	Evaporation lbs/hr	Blowdown lbs/hr	Blowdown gal/hr	Makeup water cost per hour	BTU's lost In blowdown	Cost per hour water and gas
5	6000	50040.0	12510.0	1500.0	\$5.64	3565350	\$27.03
6	6000	50040.0	10008.0	1200.0	\$4.94	2852280	\$22.05
7	6000	50040.0	8340.0	1000.0	\$4.47	2376900	\$18.73
8	6000	50040.0	7148.6	857.1	\$4.13	2037343	\$16.35
9	6000	50040.0	6255.0	750.0	\$3.88	1782675	\$14.57
10	6000	50040.0	5560.0	666.7	\$3.68	1584600	\$13.19
11	6000	50040.0	5004.0	600.0	\$3.53	1426140	\$12.08
12	6000	50040.0	4549.1	545.5	\$3.40	1296491	\$11.18
13	6000	50040.0	4170.0	500.0	\$3.29	1188450	\$10.42
14	6000	50040.0	3849.2	461.5	\$3.20	1097031	\$9.78
15	6000	50040.0	3574.3	428.6	\$3.12	1018671	\$9.23
16	6000	50040.0	3336.0	400.0	\$3.06	950760	\$8.76
17	6000	50040.0	3127.5	375.0	\$3.00	891338	\$8.34
18	6000	50040.0	2943.5	352.9	\$2.94	838906	\$7.98
19	6000	50040.0	2780.0	333.3	\$2.90	792300	\$7.65
20	6000	50040.0	2633.7	315.8	\$2.86	750600	\$7.36
21	6000	50040.0	2502.0	300.0	\$2.82	713070	\$7.10
22	6000	50040.0	2382.9	285.7	\$2.79	679114	\$6.86
23	6000	50040.0	2274.5	272.7	\$2.76	648245	\$6.65
24	6000	50040.0	2175.7	260.9	\$2.73	620061	\$6.45
25	6000	50040.0	2085.0	250.0	\$2.70	594225	\$6.27

Automated Blowdown Systems

An automatic blowdown control system continuously monitors the boiler water, adjusts the rate of blowdown, and maintains the specific conductance of the boiler water at the desired level. An automatic blowdown control system consists of a measurement probe, a control device, and a modulating blowdown control valve. Measurement of specific conductance is the mechanism used to measure solids concentration and effect control of boiler cycles of concentration. A typical automatic blowdown control system is shown in Figure 1.

Scale control in a boiler is achieved with a combination of chemicals and conductivity control. Manual blowdown removes these precipitated solids from the mud drum and lowers the total solids in the boiler. This is an important operational control that must be performed by operators on a regular schedule. Automated blowdown control will remove dissolved solids and reduce carryover due to high conductivity, reduce chemical usage by decreasing unnecessary manual blowdown, and lower fuel costs by reducing the requirement for makeup addition to the boiler.

SUMMARY

A review of field data collected from Louisiana sugar factories following the 2003 grinding season showed that the perception of boiler cleanliness is generally underestimated. The conditions of deposition, scaling and corrosion observed over a broad sampling of boiler tubes and boiler locations throughout Louisiana confirms that their general condition is less than desirable following the working season.

The conditions described have a direct impact upon fuel consumption and related costs. The use of supplemental fuels is directly related to the internal cleanliness conditions of the boiler. When problems begin, they compound one another. It does not take much of an upset to begin the process of forming deposits that lead to increased fuel consumption, wasting of heated water, increased requirement for chemical treatments, and ultimately physical damage to the boiler.

The effects of boiler downtime, outages, slowdowns and inefficient operations have a direct impact not only on sugar recovery, but also on the bottom line profits of the factory. While often the only cost assumed is the cost of the boiler chemical treatment program, we have shown that in addition to the effect on operations and sugar recovery, one must also consider the cost of fuel, repair and/or replacement of the boilers and associated equipment, and the impact these costs have on the bottom line.

REFERENCES

1. Chen, J., and C. Chou. 1993. Cane Sugar Handbook, 12th Ed., Wiley & Sons.

Figure 1. Typical automatic blowdown control system.