Plantwide Energy Assessment of a Sugarcane Farming and Processing Facility

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EXECUTIVE SUMMARY

A plantwide energy assessment was performed at Hawaiian Commercial & Sugar Co., an integrated sugarcane farming and processing facility. This investigation was performed using the internal resources of HC&S with research collaboration from the University of Hawaii's, Hawaii Natural Energy Institute, School of Ocean and Earth Sciences and Technology and the College of Tropical Agriculture and Human Resources. The UH research collaborators focused on the generation and use of steam in the sugar factory, essential to all cane sugar factory operations for generating electricity, operating mechanical equipment, and evaporating cane juice to produce raw sugar.

There were four main tasks performed for the plantwide energy assessment: 1) pump energy assessment in both field and factory operations, 2) steam generation assessment in the power production operations, 3) steam distribution assessment in the sugar manufacturing operation, and 4) electric power distribution assessment of the company system grid. The technical and economic results from the tasks should prove useful to other cane sugar operations that employ cogeneration in their operations, especially where excess electricity generated is sold to the electric utility. Demand for energy produced from biomass resources such as sugarcane bagasse may increase in the future due to government incentives created to encourage the production of more energy from renewable sources to reduce greenhouse gas emissions in the electric utility sector.

The energy savings identified in each of these tasks were summarized in terms of fuel savings, electricity savings, or opportunity revenue that potentially exists mostly from increased electric power sales to the local electric utility. The results of this investigation revealed eight energy saving projects that can be implemented at HC&S. These eight projects are summarized in Table 1 with accompanying data for fuel savings and opportunity revenue. The combined annual energy savings indicate the potential for over $1.5 million in fuel savings, 22,337 MWh equivalent electricity savings, and over $4.3 million in opportunity revenue derived mostly from additional electricity sales to the local electric utility based on electricity rates paid by the electric utility in the last quarter of 2005. About two-thirds of the savings were derived from the first four projects listed.

Table 1. Summary of Annual Fuel, Electricity, and Opportunity Cost Savings

	Fuel Savings (tons)		Fuel Value	Electricity	Opportunity
Project	Coal	Bagasse	($k)	Savings (MWh)	Revenue ($k)
1. Field pumps efficiency	247	2,392	$74	1,243	$639
2. Factory pumps efficiency	569	5,505	$169	2,861	$504
3. Steam generation	830	8,988	$269	4,554	$802
4. Second vapor use	1,750	16,936	$521	5,928	$1,043
5. Flashing condensates	663	6,418	$197	2,246	$395
6. Steam line insulation	701	6,788	$209	3,528	$621
7. Capacitor installation	113	1,095	$34	569	$100
8. Transformer replacement	280	2,708	$83	1,407	$248
Totals	**5,153**	**50,829**	**$1,555**	**22,337**	**$4,352**

If all the energy saving projects were implemented and the energy savings were realized as less fuel consumed, there would be several associated environmental benefits. Fewer air pollutants would be emitted into the atmosphere such as particulate matter, NOx, and SOx. As HC&S is already a significant user of renewable biomass fuel in its operations, the projected reductions in air pollutants and emissions will not be as great compared to if only coal fuel were used for example. Nevertheless, the combined air pollutant and emissions reduction from the fuel mix used in this study indicated there would be 146 less tons annually of regulated air pollutants emitted to the atmosphere having a total monetary value of $7,558 based on 2005 data. Also, since less coal will be used as supplemental fuel, there is the potential for reducing atmospheric CO_2 emissions by 12,733 tons. Even if there are no realized fuel savings because steam and electricity can be used for other purposes at HC&S, there will be less air pollutants and emissions per unit of fuel consumed if these energy saving projects are implemented.

A win-win situation exists for HC&S and for the public when energy efficiency improvements are implemented. For HC&S, more energy can be produced per unit of fuel, thus reducing operating costs. For the public, there will be fewer air pollutants produced as a result of combustion of fuels along with less greenhouse gas emissions in the form of atmospheric CO_2 produced by combustion of fossil fuels. HC&S will also continue to be a significant producer of electricity produced from renewable biomass energy for the island of Maui.

1 Introduction

1.1 Description of HC&S Co. Operations

The operations of Hawaiian Commercial & Sugar Co. (HC&S) consist of sugarcane farming, raw sugar and molasses manufacturing, and energy production. HC&S is a subsidiary of Alexander & Baldwin (A&B) Inc. A total of 37,000 acres are farmed in the central valley on the Island of Maui to support daily production of up to 1000 tons of raw sugar, 300 tons of molasses, and 650 megawatt-hours (MWh) of electricity. Declining commodity markets for raw sugar require HC&S to improve its productivity and reduce costs while attempting to develop new revenue streams.

HC&S currently uses 50-75% of the energy it produces. Renewable energy sources include sugarcane bagasse (the fibrous biomass residue remaining after sugar is extracted from cane) and power generated by hydro-turbines located strategically in the HC&S surface water ditch system. Supplemental fuels such as imported coal and oil are used as fuel in steam boilers to meet energy requirements. Steam and electric power are used to operate the manufacturing facility and power plant. A significant amount of electric power is also required to operate irrigation pumps located throughout the farm area. Electricity that is not used by the company is sold to the local utility under a firm power contract that requires 12 megawatts (MW) during peak hours of 7 a.m. to 9 p.m. and 8 MW during off-peak hours of 9 p.m. to 7 a.m. and on Sundays. Any reduction in energy use for operations therefore becomes an opportunity for increased electricity sales (opportunity revenue) to the utility or a reduction in fuel use.

The opportunity revenue lost as a result of inefficient energy use can be quite substantial due to higher cost of electricity and fuel in Hawaii compared with other regions of the United States. The electricity tariff rates paid for power sales to the local electric utility were $0.176/kWh in the fourth quarter of 2005. A capacity payment of $0.017/kWh is also paid if all power deliveries are met. The electric utilities in Hawaii depend on fossil fuels, most of which is imported oil [1], for about 93% of their energy needs. The electricity tariff rate paid to HC&S for power sales is highly correlated to costs paid for imported oil by the utility.

The fuels used to operate the boilers at HC&S are bagasse, imported coal, fuel oil, and a small amount of used vegetable oil. Bagasse is a byproduct of raw sugar manufacturing so its cost is relatively negligible although it can be argued that the monetary value of bagasse fuel is the same as coal on an equivalent Btu basis. On a wet mass basis, it takes about 3 tons of bagasse to provide the same fuel heating value as 1 ton of coal. The coal-equivalent fuel value of bagasse is used in this report to calculate the monetary fuel savings. The cost for coal fuel used in this report was $70 per ton wet basis (7.40% moisture).

1.2 Description of Project Tasks

The Plantwide Assessment Project at HC&S was undertaken to identify energy saving opportunities in both the farming and processing operations for sugarcane. HC&S is unique among US cane sugar producers in that it is an integrated sugarcane grower and processor. As a result, the operations of HC&S involve all aspects of growing and processing sugarcane, making the scope of investigation for energy savings quite broad.

This investigation was broken into four main tasks for energy saving opportunities: 1) pump energy assessment in both field and factory operations, 2) steam generation assessment in the electric power production operations, 3) steam distribution assessment in the sugar manufacturing operation, and 4) assessment of the electric power distribution system.

This report is presented in three main sections with results reported by both HC&S and outside collaborators. The pump energy assessment section presents measured pump efficiency data collected on targeted field and factory pumps. The steam generation and steam distribution assessments are combined into one section as most of this work was performed by the University of Hawaii research collaborators who were contracted to participate in this investigation. Their reports are attached as appendices to this report. HC&S conducted an internal review of insulation savings in the power plant area. The electric power distribution assessment results were also conducted by HC&S personnel and are summarized in a separate section of this report.

Finally, a summary of energy saving opportunities for all of the areas investigated is given in the last section of this report. The results are quantified in terms of amount of potential fuel savings, electric power savings, or opportunity revenue from electric power sales. Each energy efficiency project was also prioritized for implementation based on estimated savings and capital costs. A discussion is also presented on the actual accomplishments achieved against the goals and objectives that were originally stated for this investigation.

1.3 References

1. Hawaiian Electric Company, Inc. (n.d.). *Renewable energy: about our fuel mix*. Retrieved December 27, 2005 from http://www.heco.com

2 Pump Efficiency Assessment

2.1 Introduction

Irrigation water for HC&S is supplied mostly by watershed surface runoff and is delivered by the A&B subsidiary, East Maui Irrigation Co., through a network of ditches and stream diversions. The collected water is eventually conveyed via four main irrigation ditches, supplying water to the HC&S sugarcane farm area. A representation of the irrigation system is given in Figure 2-1. Irrigation water is also supplemented by water pumped from sixteen deep wells located throughout the farm area. The pumped water from these wells is slightly brackish as there is some mixing of fresh water with sea-water at depths below sea level and as such is less desirable compared to surface water.

Well water is finally delivered to the ditch system through 38 primary and booster pumps. The power requirement for these pumps ranges from 40 hp to 2000 hp. Also, since HC&S uses drip irrigation for most of its irrigation operations, there are approximately 150 smaller booster pumps needed to provide adequate pressure to operate the drip irrigation systems. These pumps range from 2.5 hp to 100 hp power rating.

During the dry summer months, there is heavy reliance on pumps to supply adequate irrigation water to meet the crop's irrigation requirements. Annual energy requirement to operate irrigation pumps ranges from 30,000 to 45,000 MWh depending on weather conditions. As HC&S is required to provide 12 MW of electric power to the local electric utility during peak daytime hours, there is often not enough generation capacity to meet both the utility electricity requirement and irrigation power requirement during dry periods. As a result, pumps are operated at night when the utility requires only 8 MW of export electricity and 4 MW of power are available for pumping between the hours of 9 p.m. to 7 a.m. This situation places increased demands on the pump maintenance crew to start pumps in the evening after 9 p.m. and to stop pumps in the morning before 7 a.m.

2.2 Materials and Methods

Pump efficiency testing was performed according to standards prescribed for testing of centrifugal pumps by the American Society of Mechanical Engineers and the Hydraulic Institute [1, 2]. Calibrated pressure gages were used to obtain pump inlet and outlet pressures. As prescribed by the aforementioned standards, it was noted during the pump test if valves located on the outlet end of the pump controlled flow. It was also noted if other pumps were operating in parallel with the pump-motor combination being measured.

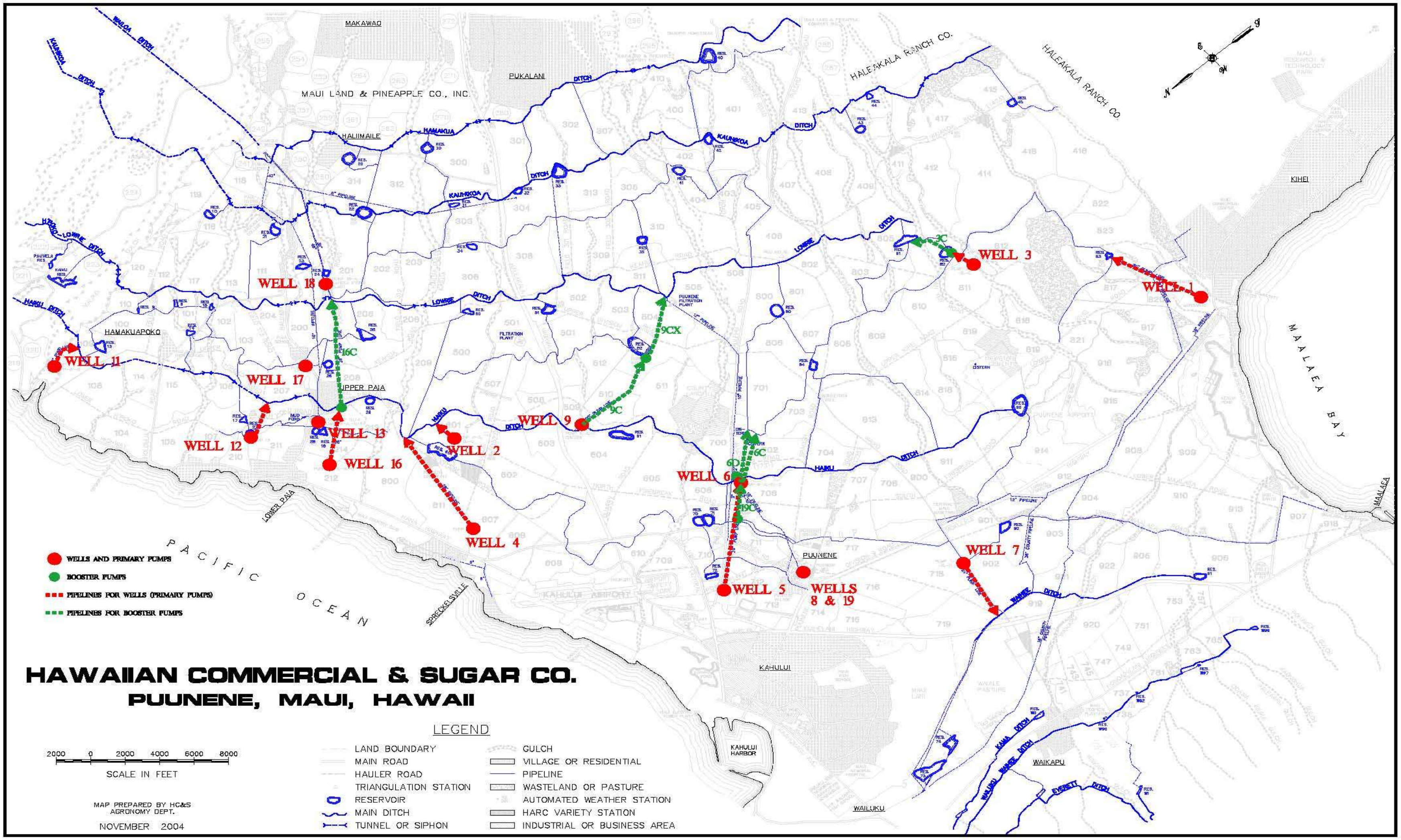

Figure 2-1. Map of farm area showing irrigation system network

Pump flow was measured where possible with a portable flow-meter (Controlotron, System 1010). The flow-meter could measure water flow using the transit time method, but in difficult conditions could also measure flow using the Doppler method that was a feature of the flow-meter. The transit time method depends on sonic transmit signals sent by a transducer traveling though the liquid and arriving at the receiver transducer without excessive attenuation. Liquids that contain an excess of gas bubbles or mineral solids are better applications for the Doppler method for measuring flow.

Electricity consumption was determined using analog readings from the motor control center for voltage, amperage, and power when available. When these readings were not available, a portable meter (General Electric Multilin Power Quality Meter, Model 501) was used to obtain the necessary electrical readings.

Data were entered into a program referred to as the Pump Systems Assessment Tool (PSAT 2004), provided by the Department of Energy Office of Industrial Technologies. Once pump head and motor electrical data were entered, the program determined pump system efficiency and provided optimization ratings for the pump system. The program also quantified energy savings in terms of annual energy units and cost savings based on annual operating hours and electricity costs. The program could also provide energy consumption information for the condition using design head and flow parameters, considered the most optimal conditions for the pump/motor combination.

Not all pumps could be measured within the survey time period. As a result, pumps were selected according to their annual usage and power rating as it was believed these pumps would provide the greatest saving opportunities.

2.3 Results and Discussion

A complete listing of the PSAT output results for the pumps tested is provided in the Appendix. A summary of measured heads and flows compared to design heads and flows for the pumps tested is provided in Table 2-1. Results for measured head readings were in close agreement with design heads. In cases where the measured heads were significantly higher than the design heads, a control valve was throttling the outlet flow. The same cannot be said for the measured pump flows compared to the design pump flows. The measured flows were found to be on average significantly lower than the specified pump flows at the design head, especially for the factory pumps.

A distinction was made between the field pumps and factory pumps because different goals apply. The goal for field pumps is to maximize the flow output of these pumps to increase the irrigation water. The goal for most of the factory pumps is to supply the precise amount of water needed for the process.

The projected energy savings and opportunity revenue for the pumps measured in this survey are presented in Table 2-2. As the goal for the field pumps was to maximize pump flow, power requirement for design head and flow conditions could actually increase from measured conditions. The electrical power requirement under optimal conditions was determined from PSAT 2004 by using the design head and flow values for the pump measured. As a result, energy requirements for optimal conditions increased in some cases. This goal was also applied to pumps used to provide cooling water to the turbine condensers in the factory division (Pump Nos. 8A, 8B, 8D, 19A, 19B). The opportunity revenue was determined by projecting the revenue that would be realized if the potential electric power savings were instead sold to the utility.

The increase in annualized flow for the optimized pump system was projected for the field pumps only based on annual operating hours. This projection was not performed for the booster pumps as these provide no incremental increase in the water that is pumped from the ground. Once this value is known, a projection was made on the increased sugar yield expected from the increased irrigation water application amount. The sugar yield projection was not performed for the factory pumps as the optimization goal is different for these pumps. Results for the field pumps showed that significant savings could be realized if pump efficiencies were improved for Pump Nos. 19C4, 18A&B, 9C, and 12.

Other distinctions noted between the field pumps and factory pumps were the operating hours were higher for the factory pumps. Even though the power ratings were lower for the factory pumps, the high operating hours associated with the factory pumps gave higher projected energy and cost savings. The largest energy savings were associated with the vertical pump system (Pump Nos. 6170, 6163, 6166, 6168) used to pump warm condenser cooling water to a cooling spray pond. The PSAT results showed that the flow output for these pumps could be provided by a 125 hp motor instead of the existing 250 hp rated motor.

As was mentioned earlier, power available for pumping is limited during dry periods due to power sales requirements to the utility company. Currently, field pumps are manually started and stopped at the pump station. The majority of pumps are split case horizontal pumps that need priming before starting. Starting of pumps is conducted manually because of pump priming and other operational issues that require physical presence to protect equipment. Shutting down pumps in a controlled manner can be achieved by radio signal to a programmable controller at the pump station from a master station located at the factory power plant.

The cost to install electric or hydraulically operated stop valves was estimated to range from $20,000 to $60,000 per pump unit. Additional solenoid valves would be needed to secure auxiliary cooling water at a cost of about $1000 per pump. An initiative is currently under way to convert all field pumps so these can be stopped automatically. The plan is to convert two pump stations per year. The operations impact would be more labor hours will then be dedicated to pump repair and maintenance. Automation would also allow slightly longer pump operating time during the off-peak hours between 9 p.m. to 7 a.m.

Table 2-1. Comparison of Measured Versus Design Heads and Flows

Pump ID	Measured Head (ft)	Design Head (ft)	% Measured Head of Design Head	Measured Flow (gpm)	Design Flow (gpm)	% Measured Flow of Design Flow
Field Pumps						
19C1	107	111	96.4%	3,595	3,475	103.5%
19C2	107	111	96.4%	3,595	3,475	103.5%
19C3	103	120	85.8%	4,861	6,850	71.0%
19C4	102	120	85.0%	4,861	6,850	71.0%
6A	185	192	96.4%	5,650	7,000	80.7%
6B	196	195	100.3%	9,554	9,700	98.5%
6C	129	132	97.8%	5,342	7,000	76.3%
11A	273	270	101.1%	2,527	2,750	91.9%
17	339	334	101.5%	6,848	8,100	84.5%
18A	499	500	99.9%	9,032	10,500	86.0%
18B	512	517	99.1%	9,358	10,500	89.1%
16A	271	295	91.8%	8,379	8,400	99.8%
16D	244	280	87.1%	5,913	6,000	98.6%
16C	374	295	126.8%	4,564	6,000	76.1%
9A	209	217	96.4%	8,796	10,500	83.8%
9C	185	195	95.0%	8,514	9,750	87.3%
9CX	162	180	89.9%	5,044	6,950	72.6%
12	266	280	94.8%	4,920	6,000	82.0%
7A	151	160	94.2%	9,016	10,400	86.7%
3A	375	390	96.1%	6,490	7,300	88.9%
3B	365	390	93.7%	6,420	7,300	87.9%
1	194	196	99.0%	3,259	4,000	81.5%
Factory Pumps						
19A	119	120	98.9%	4,036	4,900	82.4%
19B	115	120	95.6%	3,784	4,900	77.2%
8A	108	117	92.1%	2,846	3,475	81.9%
8B	108	117	92.5%	3,023	3,475	87.0%
8D	108	117	92.1%	2,177	3,475	62.6%
7717	150	110	136.1%	1383	2500	55.3%
6170	63	100	63.4%	4750	8000	59.4%
6163	59	100	58.8%	4500	8000	56.3%
6166	50	100	49.6%	4500	8000	56.3%
6168	70	100	70.4%	4500	8000	56.3%
6639	128	110	116.4%	4526	6500	69.6%

Table 2-2. Projected Energy and Cost Savings

Pump ID	Existing Motor Rated HP	Measured Motor/Pump Efficiency (%)	Annual Operating hrs.	Energy Savings (MWh)	Opportunity Revenue ($)	Incremental Increase in Pumped Water (MGPY)
Field Pumps						
19C1	125	80.4%	3,504	43	$7,603	NA
19C2	125	80.4%	3,504	43	$7,603	NA
19C3	250	61.8%	8,646	-160	-$28,195	NA
19C4	250	50.7%	8,646	142	$24,904	NA
6A	450	65.0%	2,041	52	$9,082	165
6B	600	76.7%	990	72	$12,602	9
6C	300	76.5%	2,041	-45	-$7,850	NA
11A	200	76.9%	2,505	56	$9,891	34
17	800	72.6%	1,752	83	$14,590	132
18A	1500	74.6%	2,453	155	$27,227	216
18B	2000	71.3%	894	117	$20,522	61
16A	700	78.4%	1,577	52	$9,222	2
16D	600	57.4%	876	111	$19,501	5
16C	700	67.1%	526	62	$10,912	NA
9A	800	67.2%	1,498	75	$13,253	153
9C	800	59.6%	1,419	159	$27,949	NA
9CX	300	71.7%	534	-26	-$4,541	NA
12	600	58.8%	1,901	126	$22,141	123
7A	600	70.0%	438	11	$1,971	36
3A	900	70.9%	1,393	84	$14,819	68
3B	900	75.8%	1,910	-14	-$2,376	101
1	250	68.4%	2,970	45	$7,920	132
Factory Pumps				1,243	**$218,750**	1,236
19A	200	58.8%	8,585	222	$39,054	NA
19B	200	57.5%	8,585	202	$35,587	NA
8A	150	70.3%	8,629	-11	-$1,971	NA
8B	150	69.8%	8,287	42	$7,357	NA
8D	150	51.1%	788	6	$1,038	NA
7717	125	69.3%	8,672	195	$34,250	NA
6170	250	39.2%	7,008	611	$107,589	NA
6163	250	66.6%	7,008	156	$27,403	NA
6166	250	26.8%	7,008	814	$143,264	NA
6168	250	51.8%	7,008	373	$65,613	NA
6639	250	70.4%	7,008	252	$44,352	NA
				2,861	**$503,536**	

2.4 Summary and Conclusions

The results produced from pump efficiency measurements performed on selected field and factory pumps show that significant savings can be achieved by optimizing the pump/motor systems. The largest savings opportunities appear initially to come from repairing or replacing the factory pumps that have low efficiencies. However, when the potential revenue from increased cane yield is added to the opportunity revenue from the field pumps, the overall opportunity revenue will be greater for the field pumps.

The results are summarized in Table 2-3 where both pump efficiency improvements and opportunity revenue are presented using the assumption that 1 million gallons of irrigation water applied to the developing sugarcane crop will yield the equivalent of 1 ton of sugar. The potential gross revenue that HC&S can realize from the increased sugar yield should be about $340/ton based on 2005 operating results. This figure does not take into account any expenses for processing the additional sugar in the factory nor does it include any byproduct credits from additional bagasse fuel or molasses production. The results presented in Table 2-3 show total opportunity revenue of over $1.1 million with a significant portion of this revenue derived from crop yield improvement from increased irrigation water. Given the importance of sugar yields to the operation, emphasis should be placed on improving field pumps to original specification. The measured flow results indicate there is potential for increasing pump flow either by rebuilding or by replacing the pump. Automating field pump shut-downs should provide more pumping time opportunity during the "off-peak" hours when 4 MW is available for irrigation pumping.

Table 2-3 Pump Efficiency Improvement Opportunity Revenue Summary

Division	Pump Efficiency Improvements ($1000)	Crop Yield Improvement ($1000)	Total Opportunity Revenue ($1000)
Field	$219	$420	$639
Factory	$504	NA	$504

It should be kept in mind that the savings opportunities described here apply to only those pumps measured in this survey. Other opportunities exist in improving pump efficiencies for the smaller drip pumps that require on average about 1.5 MW daily to operate. An ongoing drip pump rebuilding program is already in place at HC&S. Also, there are numerous other pumps used in the factory to convey a variety of fluids, specifically cane juice, syrup, and molasses. As these pumps are utilized throughout the grinding season (about 260 days in length) they also warrant efficiency checks.

2.5 References

1. The American Society of Mechanical Engineers. 1991. Centrifugal pumps performance test codes, ASME PTC 8.2-1990.

2. Hydraulic Institute. 2000. Centrifugal pump tests. ANSI/HI 1.6-2000.

3 Steam Generation and Distribution

3.1 Introduction

HC&S utilizes cogeneration for the simultaneous production of raw sugar and electric power. Efficient generation and use of steam is very important to any well run sugar factory, particularly if power sales and fuel savings are valued. This task was actually composed of two sub-tasks: 1) steam generation assessment in the power production operations, and 2) steam distribution assessment in the sugar manufacturing operation. The scope of work for these two sub-tasks required outside research collaboration from the University of Hawaii to assess the steam generation and distribution of steam for processing and power generation. The reports produced by the research collaborators are included in the Appendix. A brief overview and summary of their results are presented in this chapter.

Three boilers are used to generate steam at the HC&S Puunene sugar factory. These boilers are all grate-fired, stoker-type units. Boilers 1 and 2 are identical units and operate at 900 psia steam pressure with rated capacities of 120 klb steam per hour each. Boiler 3 operates at 425 psia steam pressure and is rated at 290 klb steam per hour. All three boilers are able to use multiple types of fuel. The major fuel used is biomass in the form of sugarcane bagasse. Supplementary fuels used are coal, fuel oil, and a minor amount of used cooking oil. A breakdown of the fuels used for the operation in 2004 on a percentage heating value basis is given in Table 3-1.

Table 3-1. Boiler Fuels Used (MMBtu input basis) in 2004

Fuel Type	MMBtu Fuel Input	% of Total
No. 6 fuel oil	18,724	0.3%
Diesel, No. 2	41,461	0.7%
Vegetable oil	11,087	0.2%
Coal	1,188,985	20.1%
Bagasse	4,662,816	78.7%
Totals	5,923,073	

Boiler efficiency tests were conducted by the University of Hawaii on bagasse and coal fuel for Boilers 1 and 2 and for bagasse, coal, and fuel oil for Boiler 3. A full description of the materials and methods used are provided in their report in the Appendix.

The sugar factory steam use assessment was performed by the UH research collaborators as well. A factory steam balance was established and then modeling software was applied to assess the entire process and identify areas where improvements might be made. The modeling software used was the Advanced System for Process ENgineering (ASPEN) PLUS® commercial software package form Aspen Technology Inc. (Cambridge, MA). Further analysis was performed using a pinch analysis program, Aspen Pinch.

An internal missing insulation survey was conducted by HC&S in the Puunene power plant. The annual heat loss was determined and was converted to equivalent lost fuel or steam used for power generation. An internal review was also conducted on the integration of a standby turbogenerator referred to as TG3 into normal operations. This turbogenerator has been used as a standby generator because of efficiency and reliability issues that need to be addressed internally within HC&S. The potential energy savings from integrating TG3 into normal operations will not be quantified in the results section but will only be discussed briefly as an opportunity that deserves further investigation pending internal action taken by HC&S.

3.2 Results and Discussion

Material and methods and complete results obtained from the UH research collaborators are provided in their reports included in the Appendix. A brief summary of their results is discussed in this section. Since bagasse and coal fuel are the major boiler fuels used at HC&S to generate steam, discussion will focus only on potential fuel savings using these fuels.

The UH research collaborators described opportunities for boiler efficiency gains by reducing excess air and flue gas temperature. Boiler efficiencies for the three boilers ranged from 63.2% to 67.2 % on bagasse fuel and from 76.1% to 82.4% on coal fuel. Boiler 2 had consistently lower efficiency for both fuels. It was projected that if only a 1% improvement were made in boiler efficiency using coal fuel on all three boilers, then about 9.5 tons (dry basis) of coal could be saved per day using 100% coal fuel. Similarly, a 1% improvement in boiler efficiency could save 21.5 tons (dry basis) of bagasse fuel per day using 100% bagasse fuel. In reality, a mixture of these fuels are used throughout the grinding period. No specific recommendations were provided by the UH researchers on how to improve boiler operation procedures.

About the same time results were being collected by the UH research collaborators, Alstom Power, Inc. was commissioned by HC&S to make recommendations on how to improve boiler stoker operations and reduce the particulate matter (PM) emissions when firing coal in Boiler No. 3. Although this study was not part of the scope of work of this project, the observations made by the consultant seemed to be consistent with the observations made by the UH research collaborators. Furthermore, specific recommendations were made to improve boiler operations. Some of these recommendations were:

- Install new over-fire air systems on all boilers to improve bagasse combustion
- Have dedicated mechanical feeders and distributors for bagasse and coal fuel
- Calibrate oxygen sensors and tie readings into the boiler control system
- Modify or replace the forced draft fan on Boiler 2
- Improve undergrate air distribution on Boiler 3
- Scribe and automate air bypass dampers on Boiler 3 to bypass air past the air heater when firing coal fuel

Steam use for manufacturing raw sugar was modeled as described earlier. A pinch analysis was conducted to identify significant energy saving opportunities in the sugar factory, most notably in the boiling house operations. Steam consumption for evaporating sugarcane juice and boiling sugar was determined to be in the range of 800-850 lbs steam per ton cane. As is mentioned in the report by UH researchers in the Appendix, experts predict that this steam usage figure can be reduced to 650 lbs steam per ton cane or less. Reducing the steam-to-cane ratio can make more steam available for other processes or for electricity generation and export power sales.

The two greatest steam savings opportunities identified that were deemed possible for implementation were: 1) operating the pan boiling system on second evaporator cell vapor rather than first evaporator cell vapor, and 2) increasing use of condensate flash to all evaporator cells to save steam. The combined effects of these two improvements would reduce steam-to-cane ratio by 90 lbs steam per ton cane and could increase electricity generation by 1.31 MW if saved steam was instead fully condensed in the largest turbogenerator referred to as TG4. Capital expense would be required to change heat exchange surface areas in the evaporator train, the pans, and also to increase cooling water supply and pumping capacity in the evaporator train condenser. Other steam saving opportunities were identified in the modeling effort, but were not deemed possible within the operational constraints of the sugar factory. It should also be mentioned that the two steam saving opportunities mentioned were previously tried by HC&S and were later abandoned because of negative impacts to the boiling house operation. The full modifications to the boiling house described in the UH report in the Appendix must be implemented in order to realize the potential savings described.

There are other steam saving opportunities that are known internally within HC&S that were not investigated by the UH research collaborators as their scope of work involved using only the two full-time operating turbogenerators, TG4 and TG5. An operating scenario is possible where TG3 can be operated in conjunction with TG5 using the 425 psia extraction steam from TG5 to operate TG3. The extraction steam level would have to increase from TG5, thereby reducing the amount of steam condensed by TG5. With the integration of TG3 into regular operations, preliminary indications are that 2 MW more of electricity could be generated from 30 klbs of steam from the boilers. This would mean eliminating the practice of passing steam through pressure reducing valves (PRVs) and operating the boilers near maximum capacity during peak periods. However, as mentioned earlier, there are operation reliability issues associated with TG3 and up to now this TG has only been used intermittently. Therefore, this opportunity will not be treated as a firm opportunity until the operation reliability issues are addressed internally by HC&S.

Results of the internal investigation conducted by HC&S of missing steam pipe insulation in the power plant are provided in the Appendix. The survey indicated that there is an estimated annual heat loss of 71,543 MMBtu from un-insulated steam lines in the power plant. Prevention of this heat loss would translate into either fuel savings or more energy from steam to perform work.

3.3 Summary and Conclusions

The combined steam generation and distribution savings are summarized in Table 3-2 for each of the major steam energy saving areas identified. Savings are presented in terms of annual fuel value savings and steam quantity savings. The fuel dollar value for bagasse was determined by using an equivalent coal fuel value assuming that if bagasse were not available then coal fuel would have to be used. Annual fuel savings (in terms of tons wet basis) for coal and bagasse were based partly on the fuel use data for 2004 showing nearly 80% of fuel requirement provided by bagasse and about 20% from coal. The fuel and steam savings from boiler efficiency improvement were based on the annual fuel amount consumed for both coal and bagasse in 2004 and then determining the annual amount of fuel saved if a 1% improvement in boiler efficiency was obtained. Fuel and steam savings obtained from utilizing second vapor and increasing use of condensate flash in the factory were based on 260 operating days. The projected saving from insulating steam lines in the power plant was based on 347 operating days.

The greatest energy saving opportunity identified was utilizing second evaporator cell steam vapor to operate the pans in the boiling house. However, improved insulation of steam lines in the power plant is believed to provide the shortest payback.

Table 3-2. Summary of Steam Savings Opportunities

Project	Fuel Savings Coal (tons, wb)	Fuel Savings Bagasse (tons, wb)	Fuel Value ($1000)	Annual Steam Savings (klbs/yr)
1. Boiler efficiency	830	8,988	269	67,628
2. Second vapor use	1,750	16,936	521	130,700
3. Flash condensates	663	6,418	197	49,528
4. Pipe insulation	701	6,788	209	52,383

4 Electric Power Distribution

4.1 Introduction

The electrical distribution system used at HC&S resembles that of a small utility grid. HC&S generates most of its own electric power for its operations and sells surplus electricity to the local electric utility. The maximum voltage used for the transmission distribution lines is 23 kilovolts. Voltages are stepped down from this level using electrical distribution substations in order to operate electrically driven equipment. Fifteen sub stations handle all incoming or outgoing electricity. The transmission and distribution system is key to providing electric power to operate the various irrigation pumps located throughout the farm area. The system also provides the means of distributing electric power generated from the hydro-turbines installed in the irrigation ditch system.

An ongoing program is in place at HC&S to install capacitors on motors greater than 30 hp to improve the power factor. Power factor improvements will reduce the reactive power requirement to operate electrical equipment.

Transformers with large kVA ratings require electrical energy to remain activated. This electricity used to maintain activation is referred to as "no-load loss" and is actually electrical energy converted to heat. As these transformers are necessary for electricity distribution, the transformers operate on a continuous basis during the year. Some older transformers on the HC&S grid system have already been replaced through an ongoing replacement program with proven energy savings. Replacement or consolidation of other older transformers could produce significant electrical energy savings.

4.2 Materials and Methods

Electrical test equipment was used to assess electric motors to determine the amount of capacitance needed to correct power factor. The portable Multilin Power Quality meter mentioned previously for pump efficiency testing was one of the instruments used for this purpose.

To determine transformer no-load-loss, instrumentation was used to measure current and voltage on the primary side and secondary side of the transformer. A Sensorlink Model No. 8-020 was used to measure amperage (0-2000 amps range) and a Hubbell-Chance, Model No. 62NCM, voltmeter was used to measure voltage (0-40 kilovolts range). As the transformers measured in this assessment all were associated with the well pumps, these readings were usually taken as part of the pump efficiency testing procedures.

Other power factor improvements that are possible to implement on the electrical distribution system are mentioned here, but estimates of potential annual energy savings were not determined. A quotation was obtained for a synchronous electric motor at Well 3 that is located at the extreme end of the distribution system. Synchronous electric motors are able to generate vars (reactive power) that would support voltage levels at extreme ends of the distribution system. The quotation for one synchronous electric motor with a motor control center was about $186k in 2004.

Another method to increase reactive power production is to operate an additional steam-driven turbogenerator at the Puunene power plant. This possibility exists if TG3 (normally used as a standby generator) is run in conjunction with TG5. The operation of TG3 could provide more reactive power to the 23 kV electrical system and improve the overall voltage regulation and reserve capacity of the system according to an internal power system study that was commissioned by HC&S in 2002. The integration of TG3 into regular operations was discussed briefly in the previous section for potential steam saving opportunities.

Considerable work was performed by HC&S personnel during 2005 on electrical distribution capital improvement projects. One of these projects was replacing the TG4 power management control system at the beginning of the year that cost over $800k. It is believed this upgrade contributed to over 8000 MWh of electricity sales above the 2005 operating plan for a total of 96,294 MWh of electricity sold to the electric utility in 2005. This incremental amount of electricity sold to the utility was worth over $1.4 million in additional revenue using the fourth quarter 2005 tariff rate for electricity sold. However, not all of the additional revenue noted can be attributed to the upgrading of the TG4 power management control system because of favorable hydro-power generation that enabled an additional 2 MW of electric power to be sold to the utility during peak hours.

4.3 Results and Discussion

The ongoing program of installing capacitors on electric motors greater than 30 hp in the factory area has already demonstrated electrical savings. Approximately 50% of the motors have been outfitted with capacitors and the reactive power savings was determined to be 26.67 kilovars. Using a system power factor of 0.925 in the factory area, this is equivalent to 569 MWh annual electricity savings. Assuming the remaining motors in the factory larger than 30 hp will be equipped with capacitors the potential future savings should be of the same magnitude.

As was mentioned previously, older transformers for well pumps were replaced and produced significant reductions in no-load losses. The average reduction in no-load loss was about 75% for two instances. In both cases there was a payback period of less than one year. Other candidate well pump transformer replacements are listed in Table 4-1. The measured no-load loss and projected annual electricity savings with a 75% reduction in no-load loss are also listed for these candidate transformer replacements. These results show that the transformers located at Wells 3 and 7 will provide the greatest potential savings.

Table 4-1. Candidate Electrical Transformer Replacement

Well No.	Annual No-Load-Loss (MWh)	Potential Savings @ 75% Reduction (MWh)	Opportunity Revenue ($)
6	169	127	$22,296
11	87	65	$11,471
7	750	562	$98,975
3	870	653	$114,911

4.4 Summary and Conclusions

A summary of annual electricity savings and opportunity revenue are presented in Table 4-2 for the projects investigated. Opportunity revenue could be realized if the electricity saved were sold instead to the local electric utility. The greatest potential for annual savings appears to come from electric transformer replacement.

Table 4-2. Summary of Electric Distribution System Savings

Project	Annual Electricity Savings (MWh)	Opportunity Revenue ($)
Capacitor installation	569	$100,186
Transformer replacement	1,407	$247,653

5 Summary of Savings Opportunities

5.1 Savings Summary and Discussion

Energy savings can be expressed either in terms of potential fuel savings, electrical energy savings, or opportunity revenue from electricity sales. These expressions of energy savings are not mutually exclusive where assumptions were made to perform the conversions between these terms. The fuel saving values represent a more conservative estimate of potential monetary value whereas the opportunity revenue from electricity sales will provide the highest monetary value. A more straightforward approach for fuel savings would be to use fuel heating value savings only (MMBtu), but then no distinction could be made between saved bagasse and coal fuel amounts to project reductions in air pollutants and emissions. If electrical energy savings were determined directly, then equivalent fuel savings were determined from the average annual steam requirement to produce electricity from the cogeneration system of HC&S (this study used an annual average of 14,849 lbs steam per MWh). Fuel usage in 2004 indicated that nearly 20% of fuel input heat value was provided by coal fuel and 80% from bagasse. Knowing boiler efficiencies for each of these fuels (65% on bagasse, 80% on coal), the steam produced from each fuel could be estimated. Once this information was known, fuel quantities were determined along with their monetary value. In the case where fuel savings were determined directly for the steam generation investigation, a reverse procedure was used to determine equivalent electricity potential. Overall, applying the same criteria to compare the various energy savings from each project should put into perspective their relative potential energy savings. A summary of the results is presented in Table 5-1.

As mentioned previously, the tariff rate used for electricity sales was $176/MWh, the avoided energy cost that the electric utility paid HC&S in the fourth quarter of 2005. There is also a capacity payment of about $17/MWh, but this was not included in the opportunity revenue projections as it is unknown if the electricity that would be sold to the utility would be included as dispatched power that is eligible for capacity payment.

From the data presented in Table 5-1, the major energy saving opportunities appears to come from pump efficiency improvements (field and factory) and steam efficiency improvements. It should be noted that the opportunity revenue for the field pumps includes about $420k from increased projected sugar production from increased pump water flow. The actual electrical energy savings is greater for pumps that were measured in the factory area. The combined opportunity revenue for the first four projects alone listed in Table 5-1 amounts to nearly $3 million annually. The more conservative fuel cost savings showed over $1.5 million in combined fuel cost savings for all projects in the form of coal and bagasse fuel.

Table 5-1. Summary of Annual Fuel, Electricity Savings, and Opportunity Revenue

Project	Fuel Savings (tons)		Fuel Value ($k)	Electricity Savings (MWh)	Opportunity Revenue ($k)
	Coal	Bagasse			
1. Field pumps efficiency	247	2,392	$74	1,243	$639*
2. Factory pumps efficiency	569	5,505	$169	2,861	$504
3. Steam generation	830	8,988	$269	4,554	$802
4. Second vapor use	1,750	16,936	$521	5,928	$1,043
5. Flashing condensates	663	6,418	$197	2,246	$395
6. Steam line insulation	701	6,788	$209	3,528	$621
7. Capacitor installation	113	1,095	$34	569	$100
8. Transformer replacement	280	2,708	$83	1,407	$248
Totals	**5,153**	**50,829**	**$1,555**	**22,337**	**$4,352**

* Includes $420k opportunity revenue from increased sugar yields due to increased pump flow

5.2 Classification for Implementation Priority

Each of the projects identified in this investigation were prioritized as a planning guide for future implementation. The results of this exercise are summarized in Table 5-2. Capital costs are categorized as either high capital costs requiring over $500k, medium capital cost requiring $100 to $500k, and low capital cost requiring less than $100k. Factors considered for implementation priority (classified as high, medium, or low) were potential annual fuel savings, expected payback for the initial capital cost, and operational considerations. For example, even though the annual fuel savings value is potentially high for use of second vapor steam from the evaporator station to the boiling pans, implementation of this project must be weighed against capital costs and the risk of using lower temperature steam that could possibly slow the processing rate of pan boiling operations if modifications to the evaporator cells are not fully implemented. If these projects were currently being implemented under ongoing energy efficiency improvement programs at HC&S, this is also indicated in the table.

Table 5-2. Classification of Priority Implementation

Project	Fuel Value ($k)	Expected Capital Cost	Implementation Priority	Being Implemented?
1. Field pumps efficiency	$74	$100-500k	High	Yes
2. Factory pumps efficiency	$169	$100-500k	High	No
3. Steam generation	$269	$100-500k	High	No
4. Second vapor use	$521	>$500k	Medium	No
5. Flashing condensates	$197	$100-500k	High	No
6. Steam line insulation	$209	$100-500k	High	Yes
7. Capacitor installation	$34	<$100k	High	Yes
8. Transformer replacement	$83	$100-500k	High	No

5.3 Environmental Impacts

Reduced emissions can be determined directly if energy savings are expressed in terms of equivalent fuel savings. If the energy is used instead to produce more steam and electricity for HC&S operations, then there will be less air pollutants and emissions produced per unit of fuel consumed. Additionally, there would be reduced emissions for electricity generation on the island of Maui because the utility company would not need to burn as much fossil fuel for its electrical generation. A summary of reduced air emissions potential by HC&S if all energy saving projects were implemented are provided in Table 5-3 for known air pollutants that are monitored in annual stack compliance tests. For NOx, SOx, VOC, and PM, fees are paid to the State of Hawaii for each ton of these pollutants. In 2005, these fees amounted to $51.83/ton. Therefore a reduction in fuel usage translates directly into air emission fee savings that are quantified in Table 5-3.

Table 5-3. Annual Air Pollutant Reductions from Fuel Savings (tons)

Project	NOx	SOx	CO	VOC	PM	PM10
1. Field pumps efficiency	3.3	1.4	26.2	0.9	1.2	1.1
2. Factory pumps efficiency	7.7	3.1	60.4	2.0	2.7	2.5
3. Steam generation	12.0	4.6	98.6	3.3	4.3	3.9
4. Second vapor use	23.6	9.6	185.8	6.3	8.4	7.6
5. Flashing condensates	8.9	3.7	70.4	2.4	3.2	2.9
6. Steam line insulation	9.5	3.9	74.5	2.5	3.4	3.0
7. Capacitor installation	1.6	1.1	13.7	3.0	0.5	0.6
8. Transformer replacement	3.8	1.5	29.7	1.0	1.4	1.2
Totals	**70.4**	**28.9**	**559.3**	**21.4**	**25.1**	**27.8**
Tons subject to fees	**145.8**					
Avoided emission fees	**$7,558**					

HC&S uses primarily biomass fuel for its operations, but a significant amount of coal is also used. Biomass, a renewable fuel, will not contribute net carbon dioxide to the atmosphere. However, coal is used as supplemental fuel and accounts for about 20% of the fuel input at HC&S. Coal combustion emits carbon dioxide to the atmosphere, contributing to greenhouse gases. According to EPA data in 2003 the electric utility sector emitted on average 205.9 lbs of carbon dioxide into the atmosphere for every million Btu of coal combusted [1]. Knowing the equivalent amount of coal fuel saved in this study, one can estimate the amount of reduced carbon dioxide emissions entering the atmosphere. A summary of potential reductions in CO_2 emissions is summarized in Table 5-4 for each of the energy saving projects. Although there is no monetary penalty currently paid for CO_2 emissions, coal usage is reported annually to the Energy Information Administration by HC&S to estimate greenhouse gas emissions in the United States.

Table 5-4. CO_2 Emissions Reduction from Coal Fuel (tons)

Project	CO_2 Reduction (tons)
1. Field pumps efficiency	611
2. Factory pumps efficiency	1,406
3. Steam generation	2,050
4. Second vapor use	4,324
5. Flashing condensates	1,639
6. Steam line insulation	1,733
7. Capacitor installation	279
8. Transformer replacement	691
Totals	**12,733**

5.4 Discussion of Project Accomplishments Versus Stated Goals and Objectives

The Statement of Objectives identified in the project proposal related to the four main tasks: 1) Pump Energy Assessment and Management, 2) Steam Generation Efficiency Assessment, 3) Steam Distribution Efficiency Assessment, and 4) Electric Power Distribution System Efficiency Assessment. Progress on these tasks was reported in Quarterly Progress Reports during the entire project period.

The Pump Energy Assessment task originally focused on field irrigation pumps. Data collected from these pump/motor combinations were analyzed using the DOE/OIT Pump Assessment Tool (PSAT) that was updated in 2004. Pumps that operated in the factory were also measured during the project period and revealed some significant energy saving opportunities. Although not all pumps could be measured in both the field and factory areas, the largest pumps were the focus as these require significant electric power. One of the objectives stated under this task was to spend effort on determining what the requirements would be for more automatic operation in starting and stopping well pumps used for irrigation operations. Further investigation revealed that automating pump shut off was possible, but starting pumps was more complicated because of priming requirements and other operating issues requiring physical presence for equipment protection. As a result, the investigative effort was confined to automatic pump shut downs that could help in operations where pumps need to go down quickly in order to supply electricity to the electric utility at the beginning of the peak demand period.

The Steam Generation Assessment task was performed entirely by the University of Hawaii research collaborators. The UH team was able to monitor boiler efficiency and analyze combustion gas concentrations with their portable test equipment and were able to provide valuable insights where inefficiencies existed in boiler operations. During the investigation period, an outside consultant was hired by HC&S to address a specific boiler operating matter that was outside the scope of this study. Specific recommendations were made by the consultant for modifications to boiler operations. The observations made by the consultant were consistent with the observations made by the UH team and so it would appear that the recommendations provided by the consultant would be beneficial towards improving boiler efficiencies.

The Steam Distribution Efficiency Assessment task was performed mostly by the UH research collaborators. The application of the ASPEN modeling software to the factory process steam balance was useful in identifying steam saving opportunities. The UH team was also specific on what exactly the saving opportunities were and provided some discussion on what modifications would be required to implement these changes. The application of the ASPEN modeling software precluded the use of the OIT Steam System Scoping Tool that was originally mentioned in the Statement of Objectives for the project. Regarding the work required by HC&S for steam savings, we relied on the work of an outside contractor to perform the missing insulation steam line survey and projected potential heat loss savings. The steam trap survey mentioned in the Statement of Objectives to be performed by HC&S ultimately was not performed. If this task were performed the results would not have been presented in terms of steam savings, rather in terms of improving steam quality before going to steam turbines to perform work.

The Electric Power Distribution Assessment task was presented in the Statement of Objectives as a task that would capitalize on a power system study that had been performed by an outside consultant in 2002 to recommend appropriate relay settings for electrical system protection. The goals mentioned in the Statement of Objectives described capitalizing on this work to develop a coordinated load shedding strategy and to conduct a critical review of current flows in the electric distribution system. Where transformers were under loaded, the plan was to consolidate load, where possible, to improve efficiencies. The task as it was presented in the Statement of Objectives appeared to require outside resources to help complete yet no amount was budgeted for this work. We proceeded to perform this task using HC&S internal capabilities only. As a result, this task focused more on replacing inefficient transformers with high no-load losses and to make power factor corrections where possible in the electrical distribution system.

Giving priority to this project activity was challenging given the pressures of conducting normal operations at HC&S. As a result, this work could have been performed in a shorter time period had additional outside consultants and contractors been used to perform more of the required task work, similar to how University of Hawaii research collaborators were incorporated before the project commenced for the steam generation and distribution tasks. As the potential energy savings quantified in this report are substantial, it is believed that identifying and implementing more energy saving projects will become a higher priority at HC&S.

5.5 References

1. United States Environmental Protection Agency. 2005. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003*. EPA 430-R-05-003, Washington, DC.

APPENDIX A

PSAT Results

This PSAT2004 analysis was printed at 9:12 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No (No selected)
Speed, rpm	1190
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	125
Existing motor class	Standard efficiency
rpm	1185
Rated voltage	460
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.400
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	3475
Head, ft	111.0
Load estimation method	Power
Motor voltage	478
Motor kW	84.2

	Existing	Optimal
Pump efficiency, %	92.4	90.8
Motor rated power, hp	125	125
Motor shaft power, hp	105.4	107.2
Pump shaft power, hp	105.4	107.2
Motor efficiency, %	93.4	95.0
Motor power factor, %	81.2	81.6
Motor current, amps	125.2	124.7
Motor power, kWe	84.2	84.2
Annual energy, MWhr	295.0	295.0
Annual cost, $1,000	44.3	44.3

Annual cost savings potential, $1,000	0.0
Optimization rating	100.0

Condition B

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No (No selected)
Speed, rpm	1190
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	125
Existing motor class	Standard efficiency
rpm	1185
Rated voltage	460
Nameplate FLA	148.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.400
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	3595
Head, ft	107.0
Load estimation method	Current
Motor voltage	478
Motor amps	138.0

	Existing	Optimal
Pump efficiency, %	80.4	90.7
Motor rated power, hp	125	125
Motor shaft power, hp	120.9	107.1
Pump shaft power, hp	120.9	107.1
Motor efficiency, %	93.4	95.0
Motor power factor, %	84.5	81.5
Motor current, amps	138.0	124.5
Motor power, kWe	96.5	84.1
Annual energy, MWhr	338.2	294.6
Annual cost, $1,000	50.7	44.2

Annual cost savings potential, $1,000	6.5
Optimization rating	87.1

Condition A Notes

Facility 19C1&C2 Boosters System Booster Pumps

Application Booster pump station

Date August 6, 2005 Evaluator Lee Jakeway

General comments

Design head and flow using measured electrical readings.

Condition B Notes

Facility 19C1&C2 Boosters System Booster Pumps

Application Booster pump station

Date August 6, 2005 Evaluator Lee Jakeway

General comments

Flow reading taken using transit time method and Controlotron flow meter taken on common header for 19C!&C2 outlet flow. Actual flow was for both pumps running, 19C1&C2. Flowrate used was half of this value. Head estimated from pump curve for measured flow.

This PSAT2004 analysis was printed at 9:17 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No	Speed, rpm	1190
		Drive	Direct drive
# stages	2	Specific gravity	1.000
		Fluid viscosity (cS)	1.00

Motor ratings

		Motor hp	250
Existing motor class	Energy efficient		
rpm	1185	Rated voltage	460
		Motor size margin, %	15

Duty, cost rate

Operating fraction	0.990
Electricity cost, cents/kwhr	15.000

Required or measured data

		Flowrate, gpm	6850
		Head, ft	120.0
		Load estimation method	Power
Motor voltage	483	Motor kW	175.0

	Existing	Optimal
Pump efficiency, %	92.7	91.0
Motor rated power, hp	250	300
Motor shaft power, hp	223.9	228.2
Pump shaft power, hp	223.9	228.2
Motor efficiency, %	95.4	95.3
Motor power factor, %	82.6	80.5
Motor current, amps	253.1	265.0
Motor power, kWe	175.0	178.5
Annual energy, MWhr	1517.7	1547.8
Annual cost, $1,000	227.7	232.2

Annual cost savings potential, $1,000	-4.5
Optimization rating	102.0

Condition B

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No	Speed, rpm	1190
		Drive	Direct drive
# stages	2	Specific gravity	1.000
		Fluid viscosity (cS)	1.00

Motor ratings

		Motor hp	250
Existing motor class	Energy efficient		
rpm	1190	Rated voltage	460
		Motor size margin, %	15

Duty, cost rate

Operating fraction	0.990
Electricity cost, cents/kwhr	15.000

Required or measured data

		Flowrate, gpm	4861
		Head, ft	103.0
		Load estimation method	Power
Motor voltage	487	Motor	160.0

	Existing	Optimal
Pump efficiency, %	61.8	90.7
Motor rated power, hp	250	200
Motor shaft power, hp	204.5	139.3
Pump shaft power, hp	204.5	139.3
Motor efficiency, %	95.3	95.0
Motor power factor, %	81.2	77.9
Motor current, amps	233.7	166.4
Motor power, kWe	160.0	109.3
Annual energy, MWhr	1387.6	947.9
Annual cost, $1,000	208.1	142.2

Annual cost savings potential, $1,000	65.9
Optimization rating	68.3

Condition A Notes

Facility 19C3 Booster Pump — System Booster Pumps

Application Booster pump station

Date August 9, 2005 — Evaluator Lee Jakeway

General comments

Used pump curve design flow and head and hp requirement to compare to optimum.

Condition B Notes

Facility 19C3 Booster Pump — System Booster Pumps

Application Booster pump station

Date August 9, 2005 — Evaluator Lee Jakeway

General comments

Used estimate of 7 MGD for flow based on opearations accounting. Loss coefficienct used for check valve and gate valve combination. Pump leakage noticed when measured.

This PSAT2004 analysis was printed at 9:19 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No (No selected)	Speed, rpm	1190
		Drive	Direct drive
# stages	2	Specific gravity	1.000
		Fluid viscosity (cS)	1.00

Motor ratings

		Motor hp	250
Existing motor class	Standard efficiency		
rpm	1185	Rated voltage	460
		Motor size margin, %	15

Duty, cost rate

Operating fraction	0.990
Electricity cost, cents/kwhr	15.000

Required or measured data

		Flowrate, gpm	6850
		Head, ft	120.0
		Load estimation method	Power
Motor voltage	483	Motor kW	175.0

	Existing	Optimal
Pump efficiency, %	93.8	91.0
Motor rated power, hp	250	300
Motor shaft power, hp	221.2	228.2
Pump shaft power, hp	221.2	228.2
Motor efficiency, %	94.3	95.3
Motor power factor, %	82.8	80.5
Motor current, amps	252.7	265.0
Motor power, kWe	175.0	178.5
Annual energy, MWhr	1517.7	1547.8
Annual cost, $1,000	227.7	232.2

Annual cost savings potential, $1,000	-4.5
Optimization rating	102.0

Condition B

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No (No selected)	Speed, rpm	1190
		Drive	Direct drive
# stages	2	Specific gravity	1.000
		Fluid viscosity (cS)	1.00

Motor ratings

		Motor hp	250
Existing motor class	Standard efficiency		
rpm	1185	Rated voltage	460
		Nameplate FLA	286.0
		Motor size margin, %	15

Duty, cost rate

Operating fraction	0.990
Electricity cost, cents/kwhr	15.000

Required or measured data

		Flowrate, gpm	4861
		Head, ft	101.6
		Load estimation method	Current
Motor voltage	483	Motor amps	268.0

	Existing	Optimal
Pump efficiency, %	50.7	90.7
Motor rated power, hp	250	200
Motor shaft power, hp	246.1	137.5
Pump shaft power, hp	246.1	137.5
Motor efficiency, %	94.2	95.0
Motor power factor, %	86.9	78.0
Motor current, amps	268.0	165.4
Motor power, kWe	194.8	107.9
Annual energy, MWhr	1689.3	935.8
Annual cost, $1,000	253.4	140.4

Annual cost savings potential, $1,000	113.0
Optimization rating	55.4

Condition A Notes

Facility 19C4 Booster Pump System Booster Pumps

Application Booster pump station

Date August 9, 2005 Evaluator Lee Jakeway

General comments

Used pump chart design flow and head and hp requirement to compare to optimum.

Condition B Notes

Facility 19C4 Booster Pump System Booster Pumps

Application Booster pump station

Date August 9, 2005 Evaluator Lee Jakeway

General comments

Used estimate of 7 MGD for flow based on opearations accounting. Loss coefficienct used for check valve and gate valve combination. Pump leakage and noisy operation when measured.

This PSAT2004 analysis was printed at 9:41 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm 1180

Drive Direct drive

stages 1

Specific gravity 1.000

Fluid viscosity (cS) 1.00

Motor ratings Motor hp 450

Existing motor class Standard efficiency

rpm 1180 Rated voltage 2300

Nameplate FLA 102.0

Motor size margin, % 15

Duty, cost rate Operating fraction 0.230

Electricity cost, cents/kwhr 15.000

Required or measured data

Flowrate, gpm 7000

Head, ft 192.0

Load estimation method Current

Motor voltage 2350 Motor amps 91.0

	Existing	Optimal
Pump efficiency, %	83.6	89.9
Motor rated power, hp	450	450
Motor shaft power, hp	406.1	377.4
Pump shaft power, hp	406.1	377.4
Motor efficiency, %	94.7	95.7
Motor power factor, %	86.3	83.5
Motor current, amps	91.0	86.6
Motor power, kWe	319.8	294.2
Annual energy, MWhr	644.3	592.7
Annual cost, $1,000	96.6	88.9

Annual cost savings potential, $1,000 7.7

Optimization rating 92.0

Condition B

Pump, fluid data End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm 1180

Drive Direct drive

stages 1

Specific gravity 1.000

Fluid viscosity (cS) 1.00

Motor ratings Motor hp 450

Existing motor class Standard efficiency

rpm 1180 Rated voltage 2300

Nameplate FLA 102.0

Motor size margin, % 15

Duty, cost rate Operating fraction 0.230

Electricity cost, cents/kwhr 15.000

Required or measured data

Flowrate, gpm 5650

Head, ft 185.0

Load estimation method Current

Motor voltage 2350 Motor amps 91.0

	Existing	Optimal
Pump efficiency, %	65.0	89.4
Motor rated power, hp	450	350
Motor shaft power, hp	406.1	295.3
Pump shaft power, hp	406.1	295.3
Motor efficiency, %	94.7	95.5
Motor power factor, %	86.3	83.0
Motor current, amps	91.0	68.2
Motor power, kWe	319.8	230.5
Annual energy, MWhr	644.3	464.3
Annual cost, $1,000	96.6	69.7

Annual cost savings potential, $1,000 27.0

Optimization rating 72.1

Condition A Notes

Facility Well 6 System Irrigation water

Application Pump 6A operating singular

Date Aug. 6, 2003 Evaluator Lee Jakeway

General comments

Used well chart data for optimal case.

Condition B Notes

Facility Well 6 System Irrigation water

Application Pump 6A operating singular

Date Aug. 6, 2003 Evaluator Lee Jakeway

General comments

6A operating with 6B, i.e. drawing from the same well.

This PSAT2004 analysis was printed at 9:46 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm 1185

Drive Direct drive

stages 1

Specific gravity 1.000

Fluid viscosity (cS) 1.00

Motor ratings Motor hp 600

Existing motor class Standard efficiency

rpm 1185 Rated voltage 2300

Motor size margin, % 15

Duty, cost rate Operating fraction 0.110

Electricity cost, cents/kwhr 15.000

Required or measured data

Flowrate, gpm 9700

Head, ft 195.0

Load estimation method Power

Motor voltage 2350 Motor kW 448.0

	Existing	Optimal
Pump efficiency, %	83.9	90.7
Motor rated power, hp	600	700
Motor shaft power, hp	569.4	526.7
Pump shaft power, hp	569.4	526.7
Motor efficiency, %	94.8	95.8
Motor power factor, %	85.8	83.2
Motor current, amps	128.3	121.1
Motor power, kWe	448.0	410.1
Annual energy, MWhr	431.7	395.1
Annual cost, $1,000	64.8	59.3

Annual cost savings potential, $1,000 5.5

Optimization rating 91.5

Condition B

Pump, fluid data End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm 1185

Drive Direct drive

stages 1

Specific gravity 1.000

Fluid viscosity (cS) 1.00

Motor ratings Motor hp 600

Existing motor class Standard efficiency

rpm 1185 Rated voltage 2300

Nameplate FLA 135.0

Motor size margin, % 15

Duty, cost rate Operating fraction 0.110

Electricity cost, cents/kwhr 15.000

Required or measured data

Flowrate, gpm 9554

Head, ft 195.5

Load estimation method Current

Motor voltage 2350 Motor amps 135.0

	Existing	Optimal
Pump efficiency, %	76.7	90.7
Motor rated power, hp	600	600
Motor shaft power, hp	614.6	520.3
Pump shaft power, hp	614.6	520.3
Motor efficiency, %	94.7	95.8
Motor power factor, %	88.1	84.5
Motor current, amps	135.0	117.7
Motor power, kWe	484.3	404.9
Annual energy, MWhr	466.7	390.1
Annual cost, $1,000	70.0	58.5

Annual cost savings potential, $1,000 11.5

Optimization rating 83.6

Condition A Notes

Facility Well 6 System Irrigation water

Application Pump 6B operating singular

Date Aug. 6, 2003 Evaluator Lee Jakeway

General comments

Used pump chart data for design flow and head

Condition B Notes

Facility Well 6 System Irrigation water

Application Pump 6B operating singular

Date Aug. 6, 2003 Evaluator Lee Jakeway

General comments

6B operating with 6A, i.e. drawing from the same well.

This PSAT2004 analysis was printed at 9:48 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	1175
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	300
Existing motor class	Standard efficiency
rpm	1175
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.230
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	7000
Head, ft	132.0
Load estimation method	Power
Motor voltage	2350
Motor kW	200.0

	Existing	Optimal
Pump efficiency, %	92.1	90.1
Motor rated power, hp	300	300
Motor shaft power, hp	253.3	258.8
Pump shaft power, hp	253.3	258.8
Motor efficiency, %	94.5	95.5
Motor power factor, %	83.0	83.0
Motor current, amps	59.2	59.9
Motor power, kWe	200.0	202.1
Annual energy, MWhr	403.0	407.3
Annual cost, $1,000	60.4	61.1

Annual cost savings potential, $1,000	-0.6
Optimization rating	101.1

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	1175
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	300
Existing motor class	Standard efficiency
rpm	1175
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.230
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	5342
Head, ft	129.1
Load estimation method	Power
Motor voltage	2350
Motor	180.0

	Existing	Optimal
Pump efficiency, %	76.5	89.6
Motor rated power, hp	300	250
Motor shaft power, hp	227.8	194.3
Pump shaft power, hp	227.8	194.3
Motor efficiency, %	94.4	95.3
Motor power factor, %	81.7	81.5
Motor current, amps	54.1	45.9
Motor power, kWe	180.0	152.0
Annual energy, MWhr	362.7	306.3
Annual cost, $1,000	54.4	45.9

Annual cost savings potential, $1,000	8.4
Optimization rating	84.5

Condition A Notes

Facility Well 6 — System Irrigation water

Application Pump 6C, Actual

Date Aug. 1, 2003 — Evaluator Lee Jakeway

General comments

Optimal conditions determined from well chart flow and head data

Condition B Notes

Facility Well 6 — System Irrigation water

Application Pump 6C, Actual

Date Aug. 1, 2003 — Evaluator Lee Jakeway

General comments

6C booster pump operating with 6A. Motor nameplate data not very clear so approximating this informatio based on pump report data. Also, using board reading power for load estimation method

This PSAT2004 analysis was printed at 9:49 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Double suction

Fixed pump specific speed?	No	Speed, rpm	1755
		Drive	Direct drive
# stages	3	Specific gravity	1.000
		Fluid viscosity (cS)	1.00

Motor ratings

		Motor hp	200
Existing motor class	Standard efficiency		
rpm	1770	Rated voltage	2300
		Motor size margin, %	15

Duty, cost rate

Operating fraction	0.290
Electricity cost, cents/kwhr	15.000

Required or measured data

		Flowrate, gpm	2700
		Head, ft	270.0
		Load estimation method	Power
Motor voltage	2372	Motor kW	160.0

	Existing	Optimal
Pump efficiency, %	91.4	90.4
Motor rated power, hp	200	250
Motor shaft power, hp	201.4	203.6
Pump shaft power, hp	201.4	203.6
Motor efficiency, %	93.9	95.8
Motor power factor, %	87.4	84.8
Motor current, amps	44.6	45.5
Motor power, kWe	160.0	158.4
Annual energy, MWhr	406.5	402.4
Annual cost, $1,000	61.0	60.4

Annual cost savings potential, $1,000	0.6
Optimization rating	99.0

Condition B

Pump, fluid data — Double suction

Fixed pump specific speed?	No	Speed, rpm	1755
		Drive	Direct drive
# stages	3	Specific gravity	1.000
		Fluid viscosity (cS)	1.00

Motor ratings

		Motor hp	200
Existing motor class	Standard efficiency		
rpm	1770	Rated voltage	2300
		Nameplate FLA	43.7
		Motor size margin, %	15

Duty, cost rate

Operating fraction	0.290
Electricity cost, cents/kwhr	15.000

Required or measured data

		Flowrate, gpm	2527
		Head, ft	273.0
		Load estimation method	Current
Motor voltage	2372	Motor amps	47.5

	Existing	Optimal
Pump efficiency, %	76.9	90.3
Motor rated power, hp	200	250
Motor shaft power, hp	226.5	192.9
Pump shaft power, hp	226.5	192.9
Motor efficiency, %	93.6	95.8
Motor power factor, %	92.5	84.1
Motor current, amps	47.5	43.5
Motor power, kWe	180.5	150.2
Annual energy, MWhr	458.6	381.4
Annual cost, $1,000	68.8	57.2

Annual cost savings potential, $1,000	11.6
Optimization rating	83.2

Condition A Notes

Facility Pump 11A System Well 11

Application Pump 11A, Optimal

Date August 28, 2003 Evaluator Lee Jakeway

General comments

Used pump curve data for head and flow conditions for optomal conditions

Condition B Notes

Facility Pump 11A System Well 11

Application Pump 11A, Measured

Date August 28, 2003 Evaluator Lee Jakeway

General comments

Used board electrical readings and pressure reading at dischrge of pump before check valve and gate valve assembly.
Pump used is actually a Peerless pump with an original Fairbanks-Morse vertical turbine pump unit.
Initialized full load amps to value read off of nameplate on 11-B which was identical motor

This PSAT2004 analysis was printed at 9:54 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	1220
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	800
Existing motor class	Standard efficiency
rpm	1200
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.200
Electricity cost, cents/kwhr	7.000

Required or measured data

Flowrate, gpm	8100
Head, ft	334.0
Load estimation method	Power
Motor voltage	2477
Motor kW	600.0

	Existing	Optimal
Pump efficiency, %	89.5	90.4
Motor rated power, hp	800	900
Motor shaft power, hp	763.6	755.8
Pump shaft power, hp	763.6	755.8
Motor efficiency, %	94.9	96.0
Motor power factor, %	86.5	83.8
Motor current, amps	161.7	163.3
Motor power, kWe	600.0	587.1
Annual energy, MWhr	1051.2	1028.6
Annual cost, $1,000	73.6	72.0

Annual cost savings potential, $1,000	1.6
Optimization rating	97.9

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	1220
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	800
Existing motor class	Standard efficiency
rpm	1200
Rated voltage	2300
Nameplate FLA	197.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.200
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	6848
Head, ft	338.7
Load estimation method	Current
Motor voltage	2477
Motor amps	183.0

	Existing	Optimal
Pump efficiency, %	72.6	90.0
Motor rated power, hp	800	800
Motor shaft power, hp	806.5	650.9
Pump shaft power, hp	806.5	650.9
Motor efficiency, %	94.8	95.9
Motor power factor, %	80.8	83.0
Motor current, amps	183.0	142.1
Motor power, kWe	634.4	506.0
Annual energy, MWhr	1111.5	886.6
Annual cost, $1,000	166.7	133.0

Annual cost savings potential, $1,000	33.7
Optimization rating	79.8

Condition A Notes

Facility Pump 17 System Irrigation Water

Application Pump 17, Optimal

Date July 18, 2002 Evaluator Lee Jakeway

General comments

Used well chart flow and head values

Condition B Notes

Facility Pump 17 System Irrigation Water

Application Pump 17, Measured

Date July 18, 2002 Evaluator Lee Jakeway

General comments

Pump 17 measured values, synchronous motor used here. Flow measured by a combination of open ditch flow and pipe flow to Res. 26. because could not get flow reading on pipe in well shaft

This PSAT2004 analysis was printed at 9:56 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data End suction ANSI/API

Fixed pump specific speed?	Yes / No	Speed, rpm	1200
		Drive	Direct drive
# stages	2	Specific gravity	1.000
		Fluid viscosity (cS)	1.00

Motor ratings

		Motor hp	1500
Existing motor class	Standard efficiency		
rpm	1200	Rated voltage	2300
		Motor size margin, %	15

Duty, cost rate

Operating fraction	0.280
Electricity cost, cents/kwhr	15.000

Required or measured data

		Flowrate, gpm	10500
		Head, ft	500.0
		Load estimation method	Power
Motor voltage	2427	Motor kW	1200.0

	Existing	Optimal
Pump efficiency, %	86.7	90.6
Motor rated power, hp	1500	1750
Motor shaft power, hp	1529.9	1463.1
Pump shaft power, hp	1529.9	1463.1
Motor efficiency, %	95.1	96.2
Motor power factor, %	88.4	85.0
Motor current, amps	322.8	317.6
Motor power, kWe	1200.0	1134.7
Annual energy, MWhr	2943.4	2783.3
Annual cost, $1,000	441.5	417.5

Annual cost savings potential, $1,000	24.0
Optimization rating	94.6

Condition B

Pump, fluid data End suction ANSI/API

Fixed pump specific speed?	Yes / No	Speed, rpm	1200
		Drive	Direct drive
# stages	2	Specific gravity	1.000
		Fluid viscosity (cS)	1.00

Motor ratings

		Motor hp	1500
Existing motor class	Standard efficiency		
rpm	1200	Rated voltage	2300
		Nameplate FLA	293.0
		Motor size margin, %	15

Duty, cost rate

Operating fraction	0.280
Electricity cost, cents/kwhr	15.000

Required or measured data

		Flowrate, gpm	9032
		Head, ft	499.4
		Load estimation method	Current
Motor voltage	2427	Motor amps	281.0

	Existing	Optimal
Pump efficiency, %	74.6	90.3
Motor rated power, hp	1500	1500
Motor shaft power, hp	1527.2	1261.8
Pump shaft power, hp	1527.2	1261.8
Motor efficiency, %	95.1	96.1
Motor power factor, %	101.4	85.0
Motor current, amps	281.0	274.0
Motor power, kWe	1197.8	978.8
Annual energy, MWhr	2938.0	2400.8
Annual cost, $1,000	440.7	360.1

Annual cost savings potential, $1,000	80.6
Optimization rating	81.7

Condition A Notes

Facility Pump 18A System Irrigation Water

Application Pump 18A, Optimal

Date August 7, 2002 Evaluator Lee Jakeway

General comments

Used well chart flow and head data for optimal case

Condition B Notes

Facility Pump 18A System Irrigation Water

Application Pump 18A, Measured

Date August 7, 2002 Evaluator Lee Jakeway

General comments

Pump 18A operating singularly. Synchronous motor used here. Flow value used was that measured with Controlotron.

This PSAT2004 analysis was printed at 9:56 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	1200
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	2000
Existing motor class	Standard efficiency
rpm	1200
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.100
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	10500
Head, ft	517.0
Load estimation method	Power
Motor voltage	2426
Motor kW	1200.0

	Existing	Optimal
Pump efficiency, %	89.2	88.2
Motor rated power, hp	2000	2000
Motor shaft power, hp	1536.7	1554.2
Pump shaft power, hp	1536.7	1554.2
Motor efficiency, %	95.5	96.1
Motor power factor, %	83.7	83.9
Motor current, amps	341.1	342.0
Motor power, kWe	1200.0	1205.6
Annual energy, MWhr	1051.2	1056.1
Annual cost, $1,000	157.7	158.4

Annual cost savings potential, $1,000	-0.7
Optimization rating	100.5

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	1200
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	2000
Existing motor class	Standard efficiency
rpm	1200
Rated voltage	2300
Nameplate FLA	384.6
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.100
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	9358
Head, ft	512.1
Load estimation method	Current
Motor voltage	2426
Motor amps	318.0

	Existing	Optimal
Pump efficiency, %	71.3	87.6
Motor rated power, hp	2000	1750
Motor shaft power, hp	1698.1	1381.4
Pump shaft power, hp	1698.1	1381.4
Motor efficiency, %	95.5	96.1
Motor power factor, %	99.3	84.1
Motor current, amps	318.0	303.3
Motor power, kWe	1326.6	1071.6
Annual energy, MWhr	1162.1	938.8
Annual cost, $1,000	174.3	140.8

Annual cost savings potential, $1,000	33.5
Optimization rating	80.8

Condition A Notes

Facility Pump 18 System Irrigation Water

Application Pump 18B, Optimized

Date August 7, 2002 Evaluator Lee Jakeway

General comments

Flow and head values taken from well chart for optimized case

Condition B Notes

Facility Pump 18 System Irrigation Water

Application Pump 18B, Measured

Date August 7, 2002 Evaluator Lee Jakeway

General comments

Pump 18 measured values for flow and head operating singularly. Flow was measured with Panametric flowmeter, but adjusted for Controlotron value.

This PSAT2004 analysis was printed at 10:40 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

- Fixed pump specific speed? Yes / No
- Speed, rpm: 1200
- Drive: Direct drive
- # stages: 1
- Specific gravity: 1.000
- Fluid viscosity (cS): 1.00

Motor ratings

- Motor hp: 700
- Existing motor class: Standard efficiency
- rpm: 1200
- Rated voltage: 2300
- Motor size margin, %: 15

Duty, cost rate

- Operating fraction: 0.180
- Electricity cost, cents/kwhr: 15.000

Required or measured data

- Flowrate, gpm: 8400
- Head, ft: 295.0
- Load estimation method: Power
- Motor voltage: 2400
- Motor kW: 550.0

	Existing	Optimal
Pump efficiency, %	89.5	89.7
Motor rated power, hp	700	900
Motor shaft power, hp	698.9	697.7
Pump shaft power, hp	698.9	697.7
Motor efficiency, %	94.8	95.9
Motor power factor, %	86.8	83.3
Motor current, amps	152.5	156.6
Motor power, kWe	550.0	542.4
Annual energy, MWhr	867.2	855.2
Annual cost, $1,000	130.1	128.3

Annual cost savings potential, $1,000	1.8
Optimization rating	98.6

Condition B

Pump, fluid data — End suction ANSI/API

- Fixed pump specific speed? Yes / No
- Speed, rpm: 1200
- Drive: Direct drive
- # stages: 1
- Specific gravity: 1.000
- Fluid viscosity (cS): 1.00

Motor ratings

- Motor hp: 700
- Existing motor class: Standard efficiency
- rpm: 1200
- Rated voltage: 2300
- Nameplate FLA: 138.0
- Motor size margin, %: 15

Duty, cost rate

- Operating fraction: 0.180
- Electricity cost, cents/kwhr: 15.000

Required or measured data

- Flowrate, gpm: 8379
- Head, ft: 270.7
- Load estimation method: Current
- Motor voltage: 2400
- Motor amps: 137.0

	Existing	Optimal
Pump efficiency, %	78.4	89.9
Motor rated power, hp	700	800
Motor shaft power, hp	730.7	637.1
Pump shaft power, hp	730.7	637.1
Motor efficiency, %	94.7	95.9
Motor power factor, %	101.1	83.5
Motor current, amps	137.0	142.7
Motor power, kWe	575.6	495.4
Annual energy, MWhr	907.6	781.1
Annual cost, $1,000	136.1	117.2

Annual cost savings potential, $1,000	19.0
Optimization rating	86.1

Condition A Notes

Facility Pump 16A — System Irrigation Water

Application Pump 16A, measured

Date July 12, 2002 — Evaluator Lee Jakeway

General comments

Optimal conditions determined from well chart data

Condition B Notes

Facility Pump 16A — System Irrigation Water

Application Pump 16A, measured

Date July 12, 2002 — Evaluator Lee Jakeway

General comments

Pump 16A operating singularly pumping to Haiku ditch.

This PSAT2004 analysis was printed at 10:41 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No (No selected)
Speed, rpm	1189
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	600
Existing motor class	Standard efficiency
rpm	1190
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.100
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	5913
Head, ft	243.8
Load estimation method	Power
Motor voltage	2500
Motor kW	500.0

	Existing	Optimal
Pump efficiency, %	57.4	88.9
Motor rated power, hp	600	500
Motor shaft power, hp	634.0	409.5
Pump shaft power, hp	634.0	409.5
Motor efficiency, %	94.6	95.7
Motor power factor, %	88.2	81.9
Motor current, amps	130.9	90.0
Motor power, kWe	500.0	319.1
Annual energy, MWhr	438.0	279.5
Annual cost, $1,000	65.7	41.9

Annual cost savings potential, $1,000	23.8
Optimization rating	63.8

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No (No selected)
Speed, rpm	1189
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	600
Existing motor class	Energy efficient
rpm	1190
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.100
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	6000
Head, ft	280.0
Load estimation method	Power
Motor voltage	2300
Motor	375.0

	Existing	Optimal
Pump efficiency, %	88.1	88.4
Motor rated power, hp	600	600
Motor shaft power, hp	481.4	479.7
Pump shaft power, hp	481.4	479.7
Motor efficiency, %	95.8	95.8
Motor power factor, %	84.3	84.3
Motor current, amps	111.6	111.2
Motor power, kWe	375.0	373.5
Annual energy, MWhr	328.5	327.2
Annual cost, $1,000	49.3	49.1

Annual cost savings potential, $1,000	0.2
Optimization rating	99.6

Condition A Notes

Facility Well 16 — System Irrigation Water

Application Pump 16D, measured data

Date July 22, 2005 — Evaluator Lee Jakeway

General comments

Pump 16D flow measured using Controlotron Doppler feature
Could not take flow using transit time method
Electrical readings are suspect for Amps and Voltage
Used Power reading instead
Suction pressue used from 7-11-02 readings

Condition B Notes

Facility Well 16 — System Irrigation Water

Application Pump 16D, optimized for design flow and head

Date July 22, 2005 — Evaluator Lee Jakeway

General comments

Hypothetical optimal conditions using design flow and head

This PSAT2004 analysis was printed at 10:41 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm: 1190

Drive: Direct drive

stages: 1

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings — Motor hp: 700

Existing motor class: Standard efficiency

rpm: 1200

Rated voltage: 2300

Motor size margin, %: 15

Duty, cost rate — Operating fraction: 0.060

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 6000

Head, ft: 295.0

Load estimation method: Power

Motor voltage: 2330

Motor kW: 400.0

	Existing	Optimal
Pump efficiency, %	87.7	89.9
Motor rated power, hp	700	600
Motor shaft power, hp	509.4	497.4
Pump shaft power, hp	509.4	497.4
Motor efficiency, %	95.0	95.8
Motor power factor, %	83.3	84.2
Motor current, amps	119.0	113.9
Motor power, kWe	400.0	387.1
Annual energy, MWhr	210.2	203.5
Annual cost, $1,000	31.5	30.5

Annual cost savings potential, $1,000: 1.0

Optimization rating: 96.8

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm: 1190

Drive: Direct drive

stages: 1

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings — Motor hp: 700

Existing motor class: Standard efficiency

rpm: 1200

Rated voltage: 2300

Nameplate FLA: 138.0

Motor size margin, %: 15

Duty, cost rate — Operating fraction: 0.060

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 4564

Head, ft: 374.0

Load estimation method: Current

Motor voltage: 2330

Motor amps: 126.0

	Existing	Optimal
Pump efficiency, %	67.1	89.3
Motor rated power, hp	700	600
Motor shaft power, hp	642.7	482.6
Pump shaft power, hp	642.7	482.6
Motor efficiency, %	94.9	95.8
Motor power factor, %	99.3	83.9
Motor current, amps	126.0	110.9
Motor power, kWe	505.1	375.8
Annual energy, MWhr	265.5	197.5
Annual cost, $1,000	39.8	29.6

Annual cost savings potential, $1,000: 10.2

Optimization rating: 74.4

Condition A Notes

Facility: Pump 16C — System: 16C booster system

Application: Pump 16C, Measured

Date: August 9, 2002 — Evaluator: Lee Jakeway

General comments

Optimal settings were determined using well chart and pump curve settings for flow and head.

Condition B Notes

Facility: Pump 16C — System: 16C booster system

Application: Pump 16C, Measured

Date: August 9, 2002 — Evaluator: Lee Jakeway

General comments

16C booster pump operating with 16D supply pump. Outlet valve on pump discharge was 75% closed.

This PSAT2004 analysis was printed at 10:43 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data: End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	880
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	800
Existing motor class	Standard efficiency
rpm	880
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.170
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	10500
Head, ft	217.0
Load estimation method	Power
Motor voltage	2411
Motor kW	500.0

	Existing	Optimal
Pump efficiency, %	90.5	90.8
Motor rated power, hp	800	800
Motor shaft power, hp	635.8	633.7
Pump shaft power, hp	635.8	633.7
Motor efficiency, %	94.9	95.8
Motor power factor, %	76.7	76.6
Motor current, amps	156.2	154.2
Motor power, kWe	500.0	493.3
Annual energy, MWhr	744.6	734.7
Annual cost, $1,000	111.7	110.2

Annual cost savings potential, $1,000	1.5
Optimization rating	98.7

Condition B

Pump, fluid data: End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	880
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	800
Existing motor class	Standard efficiency
rpm	880
Rated voltage	2300
Nameplate FLA	180.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.170
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	8796
Head, ft	209.1
Load estimation method	Current
Motor voltage	2411
Motor amps	153.0

	Existing	Optimal
Pump efficiency, %	67.2	90.5
Motor rated power, hp	800	600
Motor shaft power, hp	691.1	513.0
Pump shaft power, hp	691.1	513.0
Motor efficiency, %	94.8	95.6
Motor power factor, %	85.1	77.7
Motor current, amps	153.0	123.3
Motor power, kWe	543.9	400.1
Annual energy, MWhr	810.0	595.8
Annual cost, $1,000	121.5	89.4

Annual cost savings potential, $1,000	32.1
Optimization rating	73.6

Condition A Notes

Facility Well 9 | System Irrigation Water

Application Pump 9A, optimized

Date August 1, 2002 | Evaluator Lee Jakeway

General comments

Optimal conditions determined from well chart head and flow values

Condition B Notes

Facility Well 9 | System Irrigation Water

Application Pump 9A, measured

Date August 1, 2002 | Evaluator Lee Jakeway

General comments

Actual flow could not be obtained for 9A. Pump 9A flow was based on flow measurement obtained from 9C when 9A was running in series with this. Flow was adjusted upwards based on higher electrical readings when 9A was running singularly.

This PSAT2004 analysis was printed at 10:44 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed? Yes / No (No selected)

Speed, rpm: 885

Drive: Direct drive

stages: 2

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings — Motor hp: 800

Existing motor class: Standard efficiency

rpm: 890 — Rated voltage: 2300

Motor size margin, %: 15

Duty, cost rate — Operating fraction: 0.160

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 9750

Head, ft: 195.0

Load estimation method: Power

Motor voltage: 2427 — Motor kW: 400.0

	Existing	Optimal
Pump efficiency, %	94.5	90.7
Motor rated power, hp	800	700
Motor shaft power, hp	508.3	529.4
Pump shaft power, hp	508.3	529.4
Motor efficiency, %	94.8	95.7
Motor power factor, %	71.1	75.2
Motor current, amps	133.9	130.6
Motor power, kWe	400.0	412.7
Annual energy, MWhr	560.6	578.4
Annual cost, $1,000	84.1	86.8

Annual cost savings potential, $1,000: -2.7

Optimization rating: 103.2

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed? Yes / No (No selected)

Speed, rpm: 885

Drive: Direct drive

stages: 2

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings — Motor hp: 800

Existing motor class: Standard efficiency

rpm: 890 — Rated voltage: 2300

Motor size margin, %: 15

Duty, cost rate — Operating fraction: 0.160

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 8514

Head, ft: 185.2

Load estimation method: Power

Motor voltage: 2427 — Motor: 526.0

	Existing	Optimal
Pump efficiency, %	59.6	90.5
Motor rated power, hp	800	600
Motor shaft power, hp	668.6	440.1
Pump shaft power, hp	668.6	440.1
Motor efficiency, %	94.8	95.5
Motor power factor, %	77.6	74.2
Motor current, amps	161.2	110.2
Motor power, kWe	526.0	343.6
Annual energy, MWhr	737.2	481.5
Annual cost, $1,000	110.6	72.2

Annual cost savings potential, $1,000: 38.4

Optimization rating: 65.3

Condition A Notes

Facility: Pump 9C — System: Irrigation Water

Application: Well water pumping

Date: August 1, 2002 — Evaluator: Lee Jakeway

General comments

Optimal conditions using well chart head and flow.

Condition B Notes

Facility: Pump 9C — System: Irrigation Water

Application: Well water pumping

Date: August 1, 2002 — Evaluator: Lee Jakeway

General comments

Pump 9C working in series with 9A and pumping all water to Res. 52.

This PSAT2004 analysis was printed at 10:44 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

- Fixed pump specific speed? Yes / No
- Speed, rpm: 885
- Drive: Direct drive
- # stages: 1
- Specific gravity: 1.000
- Fluid viscosity (cS): 1.00

Motor ratings

- Motor hp: 300
- Existing motor class: Standard efficiency
- rpm: 1180
- Rated voltage: 2300
- Motor size margin, %: 15

Duty, cost rate

- Operating fraction: 0.060
- Electricity cost, cents/kwhr: 15.000

Required or measured data

- Flowrate, gpm: 6950
- Head, ft: 180.0
- Load estimation method: Power
- Motor voltage: 2310
- Motor kW: 275.0

	Existing	Optimal
Pump efficiency, %	91.3	89.2
Motor rated power, hp	300	450
Motor shaft power, hp	346.1	354.0
Pump shaft power, hp	346.1	354.0
Motor efficiency, %	93.9	95.6
Motor power factor, %	85.2	83.4
Motor current, amps	80.7	82.8
Motor power, kWe	275.0	276.1
Annual energy, MWhr	144.5	145.1
Annual cost, $1,000	21.7	21.8

- Annual cost savings potential, $1,000: -0.1
- Optimization rating: 100.4

Condition B

Pump, fluid data — End suction ANSI/API

- Fixed pump specific speed? Yes / No
- Speed, rpm: 885
- Drive: Direct drive
- # stages: 1
- Specific gravity: 1.000
- Fluid viscosity (cS): 1.00

Motor ratings

- Motor hp: 300
- Existing motor class: Standard efficiency
- rpm: 1180
- Rated voltage: 2300
- Nameplate FLA: 72.2
- Motor size margin, %: 15

Duty, cost rate

- Operating fraction: 0.060
- Electricity cost, cents/kwhr: 15.000

Required or measured data

- Flowrate, gpm: 5044
- Head, ft: 161.8
- Load estimation method: Current
- Motor voltage: 2310
- Motor amps: 69.0

	Existing	Optimal
Pump efficiency, %	71.7	88.2
Motor rated power, hp	300	300
Motor shaft power, hp	287.3	233.5
Pump shaft power, hp	287.3	233.5
Motor efficiency, %	94.4	95.4
Motor power factor, %	82.2	82.4
Motor current, amps	69.0	55.4
Motor power, kWe	227.0	182.6
Annual energy, MWhr	119.3	96.0
Annual cost, $1,000	17.9	14.4

- Annual cost savings potential, $1,000: 3.5
- Optimization rating: 80.4

Condition A Notes

Facility Pump 9CX System Irrigation Water

Application 9CX measured

Date August 1, 2002 Evaluator Lee Jakeway

General comments

Optimal conditions using well chart head and flow data

Condition B Notes

Facility Pump 9CX System Irrigation Water

Application 9CX measured

Date August 1, 2002 Evaluator Lee Jakeway

General comments

Pump 9CX working in series with 9A&C pumping. 9CX discharge is at Lowrie ditch

This PSAT2004 analysis was printed at 10:46 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm	1180
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	600
Existing motor class	Average
rpm	1180
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.220
Electricity cost, cents/kwhr	7.000

Required or measured data

Flowrate, gpm	6000
Head, ft	280.0
Load estimation method	Power
Motor voltage	2337
Motor kW	375.0

	Existing	Optimal
Pump efficiency, %	88.5	88.4
Motor rated power, hp	600	600
Motor shaft power, hp	479.3	480.0
Pump shaft power, hp	479.3	480.0
Motor efficiency, %	95.3	95.8
Motor power factor, %	83.9	83.8
Motor current, amps	110.4	110.2
Motor power, kWe	375.0	373.7
Annual energy, MWhr	722.7	720.2
Annual cost, $1,000	50.6	50.4

Annual cost savings potential, $1,000	0.2
Optimization rating	99.7

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm	1180
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	600
Existing motor class	Average
rpm	1180
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.220
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	4920
Head, ft	265.5
Load estimation method	Power
Motor voltage	2337
Motor	439.0

	Existing	Optimal
Pump efficiency, %	58.8	87.6
Motor rated power, hp	600	450
Motor shaft power, hp	561.0	376.4
Pump shaft power, hp	561.0	376.4
Motor efficiency, %	95.3	95.7
Motor power factor, %	85.5	83.6
Motor current, amps	126.9	86.7
Motor power, kWe	439.0	293.5
Annual energy, MWhr	846.0	565.5
Annual cost, $1,000	126.9	84.8

Annual cost savings potential, $1,000	42.1
Optimization rating	66.8

Condition A Notes

Facility Well 12 — System Irrigation Water

Application Pump 12A

Date 8-13-02 — Evaluator Lee Jakeway

General comments

Used well chart values for optimal flow and head condtions

Condition B Notes

Facility Well 12 — System Irrigation Water

Application Pump 12A

Date 8-13-02 — Evaluator Lee Jakeway

General comments

Pump measurements were made with butterfly valve only 5/8 of the way open. Reported done this way because of low sump level and to limit amperage draw on pump.

This PSAT2004 analysis was printed at 10:47 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	No
Speed, rpm	720
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	600
Existing motor class	Standard efficiency
rpm	720
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.050
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	10400
Head, ft	160.0
Load estimation method	Power
Motor voltage	2375
Motor kW	360.0

	Existing	Optimal
Pump efficiency, %	92.3	90.8
Motor rated power, hp	600	600
Motor shaft power, hp	455.3	462.9
Pump shaft power, hp	455.3	462.9
Motor efficiency, %	94.4	95.3
Motor power factor, %	71.8	72.2
Motor current, amps	121.9	121.9
Motor power, kWe	360.0	362.3
Annual energy, MWhr	157.7	158.7
Annual cost, $1,000	23.7	23.8

Annual cost savings potential, $1,000	-0.1
Optimization rating	100.6

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	No
Speed, rpm	720
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	600
Existing motor class	Standard efficiency
rpm	720
Rated voltage	2300
Nameplate FLA	148.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.050
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	9016
Head, ft	150.7
Load estimation method	Current
Motor voltage	2375
Motor amps	123.0

	Existing	Optimal
Pump efficiency, %	70.0	90.6
Motor rated power, hp	600	450
Motor shaft power, hp	490.2	378.8
Pump shaft power, hp	490.2	378.8
Motor efficiency, %	94.3	95.3
Motor power factor, %	76.7	73.5
Motor current, amps	123.0	98.0
Motor power, kWe	388.0	296.5
Annual energy, MWhr	169.9	129.8
Annual cost, $1,000	25.5	19.5

Annual cost savings potential, $1,000	6.0
Optimization rating	76.4

Condition A Notes

Facility Well 7 System Well pumps

Application Pump 7A working in series with 7C

Date 11/7/03 Evaluator Lee Jakeway

General comments

Used well chart head and flow for optimal conditions

Condition B Notes

Facility Well 7 System Well pumps

Application Pump 7A working in series with 7C

Date 11/7/03 Evaluator Lee Jakeway

General comments

Pump 7A and 7C were operating together. Flow reading was obtained at bottom of well shaft on 32" dia steel pipe with Panametric flow meter.

This PSAT2004 analysis was printed at 10:48 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

- Fixed pump specific speed? Yes / No
- Speed, rpm: 1185
- Drive: Direct drive
- # stages: 2
- Specific gravity: 1.000
- Fluid viscosity (cS): 1.00

Motor ratings

- Motor hp: 900
- Existing motor class: Standard efficiency
- rpm: 1187
- Rated voltage: 2300
- Motor size margin, %: 15

Duty, cost rate

- Operating fraction: 0.160
- Electricity cost, cents/kwhr: 15.000

Required or measured data

- Flowrate, gpm: 7300
- Head, ft: 390.0
- Load estimation method: Power
- Motor voltage: 2350
- Motor kW: 650.0

	Existing	Optimal
Pump efficiency, %	86.8	90.0
Motor rated power, hp	900	1000
Motor shaft power, hp	828.1	798.6
Pump shaft power, hp	828.1	798.6
Motor efficiency, %	95.0	96.0
Motor power factor, %	86.3	84.6
Motor current, amps	185.0	180.1
Motor power, kWe	650.0	620.4
Annual energy, MWhr	911.0	869.5
Annual cost, $1,000	136.7	130.4

Annual cost savings potential, $1,000: 6.2

Optimization rating: 95.4

Condition B

Pump, fluid data — End suction ANSI/API

- Fixed pump specific speed? Yes / No
- Speed, rpm: 1185
- Drive: Direct drive
- # stages: 2
- Specific gravity: 1.000
- Fluid viscosity (cS): 1.00

Motor ratings

- Motor hp: 900
- Existing motor class: Standard efficiency
- rpm: 1187
- Rated voltage: 2300
- Nameplate FLA: 201.0
- Motor size margin, %: 15

Duty, cost rate

- Operating fraction: 0.160
- Electricity cost, cents/kwhr: 15.000

Required or measured data

- Flowrate, gpm: 6490
- Head, ft: 374.7
- Load estimation method: Current
- Motor voltage: 2350
- Motor amps: 190.0

	Existing	Optimal
Pump efficiency, %	70.9	89.8
Motor rated power, hp	900	800
Motor shaft power, hp	866.3	684.0
Pump shaft power, hp	866.3	684.0
Motor efficiency, %	95.0	95.9
Motor power factor, %	88.0	85.0
Motor current, amps	190.0	153.7
Motor power, kWe	680.4	531.6
Annual energy, MWhr	953.7	745.1
Annual cost, $1,000	143.0	111.8

Annual cost savings potential, $1,000: 31.3

Optimization rating: 78.1

Condition A Notes

Facility HC&S — System Irrigation Water

Application Pump 3A, Using 2004 pump operating hours

Date April 20, 2005 — Evaluator Lee Jakeway

General comments

Optimized settings determined from pump curce data

Condition B Notes

Facility HC&S — System Irrigation Water

Application Pump 3A, Using 2004 pump operating hours

Date April 20, 2005 — Evaluator Lee Jakeway

General comments

Pump efficiency testing at Well 3 after pipeline replacement to Res. 82
Throttle valve at outlet of pump fully open.

This PSAT2004 analysis was printed at 10:50 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	No
Speed, rpm	1185
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	900
Existing motor class	Standard efficiency
rpm	1187
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.220
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	7300
Head, ft	390.0
Load estimation method	Power
Motor voltage	2325
Motor kW	600.0

	Existing	Optimal
Pump efficiency, %	94.0	90.0
Motor rated power, hp	900	1000
Motor shaft power, hp	765.0	798.6
Pump shaft power, hp	765.0	798.6
Motor efficiency, %	95.1	96.0
Motor power factor, %	85.7	85.0
Motor current, amps	174.0	181.3
Motor power, kWe	600.0	620.4
Annual energy, MWhr	1156.3	1195.5
Annual cost, $1,000	173.4	179.3

Annual cost savings potential, $1,000	-5.9
Optimization rating	103.4

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	No
Speed, rpm	1185
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	900
Existing motor class	Standard efficiency
rpm	1187
Rated voltage	2300
Nameplate FLA	201.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.220
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	6420
Head, ft	365.4
Load estimation method	Current
Motor voltage	2325
Motor amps	175.0

	Existing	Optimal
Pump efficiency, %	75.8	89.8
Motor rated power, hp	900	800
Motor shaft power, hp	781.9	659.9
Pump shaft power, hp	781.9	659.9
Motor efficiency, %	95.1	95.9
Motor power factor, %	87.0	84.9
Motor current, amps	175.0	150.1
Motor power, kWe	613.3	512.9
Annual energy, MWhr	1182.0	988.5
Annual cost, $1,000	177.3	148.3

Annual cost savings potential, $1,000	29.0
Optimization rating	83.6

Condition A Notes

Facility HC&S System Irrigation Water

Application Pump 3B, 2005 results

Date April 20, 2005 Evaluator Lee Jakeway

General comments

Optimal settings using pump curve values

Condition B Notes

Facility HC&S System Irrigation Water

Application Pump 3B, 2005 results

Date April 20, 2005 Evaluator Lee Jakeway

General comments

Pump efficiency testing at Well 3 after pipeline change made
Throttle valve at outlet of pump fully open. Used 2004 operating hours to determine operating fraction
Controlotron flow meter used

This PSAT2004 analysis was printed at 10:52 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Double suction

Fixed pump specific speed?	Yes / No
Speed, rpm	1770
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	250
Existing motor class	Standard efficiency
rpm	1775
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.340
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	4000
Head, ft	196.0
Load estimation method	Power
Motor voltage	2320
Motor kW	200.0

	Existing	Optimal
Pump efficiency, %	78.4	90.9
Motor rated power, hp	250	300
Motor shaft power, hp	252.6	217.8
Pump shaft power, hp	252.6	217.8
Motor efficiency, %	94.2	95.8
Motor power factor, %	87.4	84.4
Motor current, amps	56.9	50.0
Motor power, kWe	200.0	169.5
Annual energy, MWhr	595.7	504.8
Annual cost, $1,000	89.4	75.7

Annual cost savings potential, $1,000	13.6
Optimization rating	84.7

Condition B

Pump, fluid data — Double suction

Fixed pump specific speed?	Yes / No
Speed, rpm	1770
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	250
Existing motor class	Standard efficiency
rpm	1775
Rated voltage	2300
Nameplate FLA	56.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.340
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	3259
Head, ft	194.0
Load estimation method	Current
Motor voltage	2320
Motor amps	52.0

	Existing	Optimal
Pump efficiency, %	68.4	90.7
Motor rated power, hp	250	250
Motor shaft power, hp	233.3	176.0
Pump shaft power, hp	233.3	176.0
Motor efficiency, %	94.3	95.7
Motor power factor, %	88.3	83.9
Motor current, amps	52.0	40.7
Motor power, kWe	184.6	137.1
Annual energy, MWhr	549.8	408.3
Annual cost, $1,000	82.5	61.2

Annual cost savings potential, $1,000	21.2
Optimization rating	74.3

Condition A Notes

Facility Well 1 System Well Pump

Application Pump 1

Date November 11, 2003 Evaluator Lee Jakeway

General comments

Optimal settings determined fromwell chart flow and head values

Condition B Notes

Facility Well 1 System Well Pump

Application Pump 1

Date November 11, 2003 Evaluator Lee Jakeway

General comments

Data collected from Well 1. Check valve and stop valve were part of system at pump outlet. Flow measurement was taken using Panametric flow meter on 20" cast iron pipe, 0.8 wall thickness, near reservoir 83 outlet. Electrical readings were taken from analog meters on the board.

This PSAT2004 analysis was printed at 10:55 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data: Double suction

Fixed pump specific speed? Yes / No

Speed, rpm: 1180

Drive: Direct drive

\# stages: 3

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings

Motor hp: 200

Existing motor class: Standard efficiency

rpm: 1180

Rated voltage: 460

Motor size margin, %: 15

Duty, cost rate

Operating fraction: 0.980

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 4900

Head, ft: 120.0

Load estimation method: Power

Motor voltage: 450

Motor kW: 131.0

	Existing	Optimal
Pump efficiency, %	89.9	89.9
Motor rated power, hp	200	200
Motor shaft power, hp	165.1	165.1
Pump shaft power, hp	165.1	165.1
Motor efficiency, %	94.0	95.3
Motor power factor, %	83.3	83.1
Motor current, amps	201.7	199.5
Motor power, kWe	131.0	129.3
Annual energy, MWhr	1124.6	1109.6
Annual cost, $1,000	168.7	166.4

Annual cost savings potential, $1,000: 2.3

Optimization rating: 98.7

Condition B

Pump, fluid data: Double suction

Fixed pump specific speed? Yes / No

Speed, rpm: 1180

Drive: Direct drive

\# stages: 3

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings

Motor hp: 200

Existing motor class: Standard efficiency

rpm: 1180

Rated voltage: 460

Motor size margin, %: 15

Duty, cost rate

Operating fraction: 0.980

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 4036

Head, ft: 118.7

Load estimation method: Power

Motor voltage: 450

Motor: 155.1

	Existing	Optimal
Pump efficiency, %	61.9	90.1
Motor rated power, hp	200	200
Motor shaft power, hp	195.4	134.3
Pump shaft power, hp	195.4	134.3
Motor efficiency, %	94.0	95.0
Motor power factor, %	83.9	81.2
Motor current, amps	237.3	166.7
Motor power, kWe	155.1	105.4
Annual energy, MWhr	1331.5	905.1
Annual cost, $1,000	199.7	135.8

Annual cost savings potential, $1,000: 64.0

Optimization rating: 68.0

Condition A Notes

Facility: Well 19

System: Power Plant Water

Application: Pump 19A

Date: July 16, 2003

Evaluator: Lee Jakeway

General comments

Pump curve data used for optimal conditions

Condition B Notes

Facility: Well 19

System: Power Plant Water

Application: Pump 19A

Date: July 16, 2003

Evaluator: Lee Jakeway

General comments

Data obtained when 19A running singularly, 19B was down. No trouble experienced with power plant cooling. They were measuring about 15 psi going into TG5 generator cooler.

This PSAT2004 analysis was printed at 10:55 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Double suction

Fixed pump specific speed?	No
Speed, rpm	1180
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	200
Existing motor class	Standard efficiency
rpm	1180
Rated voltage	460
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.980
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	4900
Head, ft	120.0
Load estimation method	Power
Motor voltage	450
Motor kW	128.0

	Existing	Optimal
Pump efficiency, %	92.1	91.1
Motor rated power, hp	200	200
Motor shaft power, hp	161.3	163.0
Pump shaft power, hp	161.3	163.0
Motor efficiency, %	94.0	95.2
Motor power factor, %	83.2	83.0
Motor current, amps	197.4	197.2
Motor power, kWe	128.0	127.6
Annual energy, MWhr	1098.9	1095.8
Annual cost, $1,000	164.8	164.4

Annual cost savings potential, $1,000	0.5
Optimization rating	99.7

Condition B

Pump, fluid data — Double suction

Fixed pump specific speed?	No
Speed, rpm	1180
Drive	Direct drive
# stages	2
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	200
Existing motor class	Standard efficiency
rpm	1180
Rated voltage	460
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.980
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	3784
Head, ft	114.7
Load estimation method	Power
Motor voltage	450
Motor	151.2

	Existing	Optimal
Pump efficiency, %	57.5	91.0
Motor rated power, hp	200	150
Motor shaft power, hp	190.5	120.5
Pump shaft power, hp	190.5	120.5
Motor efficiency, %	94.0	95.1
Motor power factor, %	83.8	82.6
Motor current, amps	231.4	146.7
Motor power, kWe	151.2	94.5
Annual energy, MWhr	1298.0	811.0
Annual cost, $1,000	194.7	121.6

Annual cost savings potential, $1,000	73.1
Optimization rating	62.5

Condition A Notes

Facility Well 19 — System Power Plant Water

Application Pump 19B

Date July 16, 2003 — Evaluator Lee Jakeway

General comments

Data for design conditions according to pump curve

Condition B Notes

Facility Well 19 — System Power Plant Water

Application Pump 19B

Date July 16, 2003 — Evaluator Lee Jakeway

General comments

Data obtained when 19B running singularly. Experienced trouble at first when some flow was going back to 19A because of faulty check valve. Problem was corrected by closing gate valve on 19A then taking readings for 19B.

This PSAT2004 analysis was printed at 10:58 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Double suction

Fixed pump specific speed?	Yes / No
Speed, rpm	1160
Drive	Direct drive
# stages	3
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	150
Existing motor class	Standard efficiency
rpm	1190
Rated voltage	480
Nameplate FLA	170.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.990
Electricity cost, cents/kwhr	10.000

Required or measured data

Flowrate, gpm	3475
Head, ft	117.0
Load estimation method	Current
Motor voltage	471
Motor amps	129.8

	Existing	Optimal
Pump efficiency, %	93.1	90.2
Motor rated power, hp	150	150
Motor shaft power, hp	110.2	113.8
Pump shaft power, hp	110.2	113.8
Motor efficiency, %	93.4	95.0
Motor power factor, %	83.1	82.0
Motor current, amps	129.8	133.5
Motor power, kWe	88.0	89.3
Annual energy, MWhr	763.3	774.5
Annual cost, $1,000	76.3	77.5

Annual cost savings potential, $1,000	-1.1
Optimization rating	101.5

Condition B

Pump, fluid data — Double suction

Fixed pump specific speed?	Yes / No
Speed, rpm	1160
Drive	Direct drive
# stages	3
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	150
Existing motor class	Standard efficiency
rpm	1190
Rated voltage	480
Nameplate FLA	170.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.990
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	2846
Head, ft	107.8
Load estimation method	Current
Motor voltage	471
Motor amps	129.8

	Existing	Optimal
Pump efficiency, %	70.3	90.0
Motor rated power, hp	150	100
Motor shaft power, hp	110.2	86.1
Pump shaft power, hp	110.2	86.1
Motor efficiency, %	93.4	94.8
Motor power factor, %	83.1	82.8
Motor current, amps	129.8	100.2
Motor power, kWe	88.0	67.7
Annual energy, MWhr	763.3	587.1
Annual cost, $1,000	114.5	88.1

Annual cost savings potential, $1,000	26.4
Optimization rating	76.9

Condition A Notes

Facility Well 8
System Condenser Cooling Water
Application Pump 8A
Date May 27, 2004
Evaluator Lee Jakeway
General comments

Used "well chart"required head and flow data

Condition B Notes

Facility Well 8
System Condenser Cooling Water
Application Pump 8A
Date May 27, 2004
Evaluator Lee Jakeway
General comments

Pump 8A flow determined by difference and prorated based on amperage reading with 8A and 8B. Revised flow figure used from 7/28/04 results

This PSAT2004 analysis was printed at 10:58 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Double suction

Fixed pump specific speed?	No
Speed, rpm	1160
Drive	Direct drive
# stages	3
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	150
Existing motor class	Standard efficiency
rpm	1193
Rated voltage	480
Nameplate FLA	170.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.950
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	3475
Head, ft	117.0
Load estimation method	Current
Motor voltage	471
Motor amps	138.0

	Existing	Optimal
Pump efficiency, %	86.8	90.2
Motor rated power, hp	150	150
Motor shaft power, hp	118.3	113.8
Pump shaft power, hp	118.3	113.8
Motor efficiency, %	93.5	95.0
Motor power factor, %	83.8	82.0
Motor current, amps	138.0	133.5
Motor power, kWe	94.3	89.3
Annual energy, MWhr	785.0	743.2
Annual cost, $1,000	117.8	111.5

Annual cost savings potential, $1,000	6.3
Optimization rating	94.7

Condition B

Pump, fluid data — Double suction

Fixed pump specific speed?	No
Speed, rpm	1160
Drive	Direct drive
# stages	3
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	150
Existing motor class	Standard efficiency
rpm	1193
Rated voltage	480
Nameplate FLA	170.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.950
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	3023
Head, ft	108.2
Load estimation method	Current
Motor voltage	471
Motor amps	138.0

	Existing	Optimal
Pump efficiency, %	69.8	90.0
Motor rated power, hp	150	125
Motor shaft power, hp	118.3	91.8
Pump shaft power, hp	118.3	91.8
Motor efficiency, %	93.5	94.9
Motor power factor, %	83.8	81.6
Motor current, amps	138.0	108.4
Motor power, kWe	94.3	72.1
Annual energy, MWhr	785.0	600.3
Annual cost, $1,000	117.8	90.0

Annual cost savings potential, $1,000	27.7
Optimization rating	76.5

Condition A Notes

Facility Well 8 System Condenser Cooling Water

Application Pump 8B

Date May 27, 2004 Evaluator Lee Jakeway

General comments

Determined from Well Chart Data for head and flow

Condition B Notes

Facility Well 8 System Condenser Cooling Water

Application Pump 8B

Date May 27, 2004 Evaluator Lee Jakeway

General comments

Pump 8B flow determined by difference and prorated based on amperage reading with 8A and 8B and using revised flow number partly determined from 7/28/04 flow measurements

This PSAT2004 analysis was printed at 10:58 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data: Double suction

Fixed pump specific speed?	Yes / No
Speed, rpm	1160
Drive	Direct drive
# stages	3
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	150
Existing motor class	Standard efficiency
rpm	1175
Rated voltage	440
Nameplate FLA	190.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.090
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	3475
Head, ft	111.0
Load estimation method	Current
Motor voltage	470
Motor amps	144.4

	Existing	Optimal
Pump efficiency, %	84.0	90.0
Motor rated power, hp	150	125
Motor shaft power, hp	115.9	108.2
Pump shaft power, hp	115.9	108.2
Motor efficiency, %	93.5	95.0
Motor power factor, %	78.7	81.2
Motor current, amps	144.4	128.5
Motor power, kWe	92.5	84.9
Annual energy, MWhr	72.9	67.0
Annual cost, $1,000	10.9	10.0

Annual cost savings potential, $1,000	0.9
Optimization rating	91.9

Condition B

Pump, fluid data: Double suction

Fixed pump specific speed?	Yes / No
Speed, rpm	1160
Drive	Direct drive
# stages	3
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	150
Existing motor class	Standard efficiency
rpm	1175
Rated voltage	440
Nameplate FLA	190.0
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.090
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	2177
Head, ft	107.8
Load estimation method	Current
Motor voltage	470
Motor amps	144.4

	Existing	Optimal
Pump efficiency, %	51.1	89.8
Motor rated power, hp	150	100
Motor shaft power, hp	115.9	66.0
Pump shaft power, hp	115.9	66.0
Motor efficiency, %	93.5	94.7
Motor power factor, %	78.7	75.4
Motor current, amps	144.4	84.6
Motor power, kWe	92.5	51.9
Annual energy, MWhr	72.9	40.9
Annual cost, $1,000	10.9	6.1

Annual cost savings potential, $1,000	4.8
Optimization rating	56.2

Condition A Notes

Facility Well 8 System Condenser Cooling Water

Application Pump 8D

Date July 28, 2004 Evaluator Lee Jakeway

General comments

Optimal conditions using well chart flow and head data

Condition B Notes

Facility Well 8 System Condenser Cooling Water

Application Pump 8D

Date July 28, 2004 Evaluator Lee Jakeway

General comments

Pump 8D flow determined by difference and prorated based on amperage reading with 8A and 8B. Used half of flow measured indirectly.

This PSAT2004 analysis was printed at 11:00 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	1750
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	60
Existing motor class	Standard efficiency
rpm	1780
Rated voltage	460
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.990
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	1500
Head, ft	110.0
Load estimation method	Power
Motor voltage	460
Motor kW	40.0

	Existing	Optimal
Pump efficiency, %	84.6	86.0
Motor rated power, hp	60	60
Motor shaft power, hp	49.3	48.4
Pump shaft power, hp	49.3	48.4
Motor efficiency, %	91.9	94.4
Motor power factor, %	84.0	84.4
Motor current, amps	59.7	56.8
Motor power, kWe	40.0	38.3
Annual energy, MWhr	346.9	331.8
Annual cost, $1,000	52.0	49.8

Annual cost savings potential, $1,000	2.3
Optimization rating	95.7

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed?	Yes / No
Speed, rpm	1750
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	125
Existing motor class	Standard efficiency
rpm	1780
Rated voltage	460
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.990
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	1383
Head, ft	149.7
Load estimation method	Power
Motor voltage	460
Motor	60.7

	Existing	Optimal
Pump efficiency, %	69.3	85.0
Motor rated power, hp	125	75
Motor shaft power, hp	75.5	61.5
Pump shaft power, hp	75.5	61.5
Motor efficiency, %	92.8	94.7
Motor power factor, %	81.9	85.0
Motor current, amps	92.9	71.4
Motor power, kWe	60.7	48.4
Annual energy, MWhr	526.4	419.9
Annual cost, $1,000	79.0	63.0

Annual cost savings potential, $1,000	16.0
Optimization rating	79.8

Condition A Notes

Facility Equip No. 7717 System Wet Scrubber

Application Optimized wet scrubber system supply pump

Date October 21, 2004 Evaluator Lee Jakeway

General comments

Optimized using existing pump BEP for head, 110' and estimated flow required for wet scrubber systems based on measured flow after Blr. 3 wet scrubber recycle system installed.

Condition B Notes

Facility Equip No. 7717 System Wet Scrubber

Application Wet scrubber system supply pump

Date October 21, 2004 Evaluator Lee Jakeway

General comments

Valve was nearly fully closed on Blr 3 supply and partially open on Blr 1&2 supply with actual power readings that were taken shortly after using the multi-lin recorder over a 90 minute period.

This PSAT2004 analysis was printed at 11:03 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data: Vertical turbine

Fixed pump specific speed? Yes / No

Speed, rpm: 1785

Drive: Direct drive

stages: 1

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings

Motor hp: 250

Existing motor class: Energy efficient

rpm: 1775

Rated voltage: 2300

Motor size margin, %: 15

Duty, cost rate

Operating fraction: 0.800

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 8000

Head, ft: 100.0

Load estimation method: Power

Motor voltage: 2320

Motor kW: 172.0

	Existing	Optimal
Pump efficiency, %	91.4	90.7
Motor rated power, hp	250	300
Motor shaft power, hp	221.0	222.8
Pump shaft power, hp	221.0	222.8
Motor efficiency, %	95.9	95.8
Motor power factor, %	86.1	84.7
Motor current, amps	49.7	50.9
Motor power, kWe	172.0	173.3
Annual energy, MWhr	1205.4	1214.7
Annual cost, $1,000	180.8	182.2

Annual cost savings potential, $1,000: -1.4

Optimization rating: 100.8

Condition B

Pump, fluid data: Vertical turbine

Fixed pump specific speed? Yes / No

Speed, rpm: 1785

Drive: Direct drive

stages: 1

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings

Motor hp: 250

Existing motor class: Standard efficiency

rpm: 1775

Rated voltage: 2300

Nameplate FLA: 58.5

Motor size margin, %: 15

Duty, cost rate

Operating fraction: 0.800

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 4750

Head, ft: 63.4

Load estimation method: Current

Motor voltage: 2320

Motor amps: 46.0

	Existing	Optimal
Pump efficiency, %	39.2	89.6
Motor rated power, hp	250	100
Motor shaft power, hp	194.3	84.9
Pump shaft power, hp	194.3	84.9
Motor efficiency, %	94.2	95.1
Motor power factor, %	83.2	85.4
Motor current, amps	46.0	19.4
Motor power, kWe	153.8	66.6
Annual energy, MWhr	1078.1	466.8
Annual cost, $1,000	161.7	70.0

Annual cost savings potential, $1,000: 91.7

Optimization rating: 43.3

Condition A Notes

Facility: Pump No. 6170

System: Factory Vertical Pumps

Application: Spray pond recirculation system

Date: September 28, 2005

Evaluator: Lee Jakeway

General comments

Optimized conditions using pump curve information. Pump no. 6170 is one of four vertical pumps that pump boiling house condenser cooling water back to the spray pond for cooling. Water returns to factory and is then pumped to boiling house evaporators and pans via booster pumps. Three other vertical pumps were operating during the test.

Condition B Notes

Facility: Pump No. 6170

System: Factory Vertical Pumps

Application: Spray pond recirculation system

Date: September 28, 2005

Evaluator: Lee Jakeway

General comments

Actual operating conditions. Pump no. 6170 is one of four vertical pumps that pump boiling house condenser cooling water back to the spray pond for cooling. Water returns to factory and is then pumped to boiling house evaporators and pans via booster pumps. Three other vertical pumps were operating during the test. Flow measured with flow meter using Doppler feature. Electrical readings taken from board panel. Reportedly, pump shafts were shortened thus modifying pump output curve

This PSAT2004 analysis was printed at 11:04 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data: Vertical turbine

Fixed pump specific speed? Yes / No

Speed, rpm: 1785

Drive: Direct drive

stages: 1

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings: Motor hp: 250

Existing motor class: Energy efficient

rpm: 1775

Rated voltage: 2300

Motor size margin, %: 15

Duty, cost rate: Operating fraction: 0.800

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 8000

Head, ft: 100.0

Load estimation method: Power

Motor voltage: 2410

Motor kW: 172.0

	Existing	Optimal
Pump efficiency, %	91.4	90.7
Motor rated power, hp	250	300
Motor shaft power, hp	221.0	222.8
Pump shaft power, hp	221.0	222.8
Motor efficiency, %	95.9	95.8
Motor power factor, %	85.4	83.1
Motor current, amps	48.2	50.0
Motor power, kWe	172.0	173.3
Annual energy, MWhr	1205.4	1214.7
Annual cost, $1,000	180.8	182.2

Annual cost savings potential, $1,000: -1.4

Optimization rating: 100.8

Condition B

Pump, fluid data: Vertical turbine

Fixed pump specific speed? Yes / No

Speed, rpm: 1785

Drive: Direct drive

stages: 1

Specific gravity: 1.000

Fluid viscosity (cS): 1.00

Motor ratings: Motor hp: 250

Existing motor class: Standard efficiency

rpm: 1775

Rated voltage: 2300

Nameplate FLA: 58.5

Motor size margin, %: 15

Duty, cost rate: Operating fraction: 0.800

Electricity cost, cents/kwhr: 15.000

Required or measured data

Flowrate, gpm: 4500

Head, ft: 58.8

Load estimation method: Current

Motor voltage: 2410

Motor amps: 28.0

	Existing	Optimal
Pump efficiency, %	66.6	89.3
Motor rated power, hp	250	100
Motor shaft power, hp	100.3	74.8
Pump shaft power, hp	100.3	74.8
Motor efficiency, %	92.5	95.1
Motor power factor, %	69.2	82.5
Motor current, amps	28.0	17.0
Motor power, kWe	80.9	58.7
Annual energy, MWhr	566.8	411.1
Annual cost, $1,000	85.0	61.7

Annual cost savings potential, $1,000: 23.4

Optimization rating: 72.5

Condition A Notes

Facility: Pump 6163 | System: Factory Vertical Pumps

Application: Spray pond recirculation system

Date: September 28, 2005 | Evaluator: Lee Jakeway

General comments

Optimal operating conditions using pump curve data. Pump no. 6163 is one of four vertical pumps that pumps boiling house condenser cooling water back to the spray pond for cooling. Water returns to factory and is then pumped to boiling house evaporators and pans via booster pumps. Three other vertical pumps were operating during the test.

Condition B Notes

Facility: Pump 6163 | System: Factory Vertical Pumps

Application: Spray pond recirculation system

Date: September 28, 2005 | Evaluator: Lee Jakeway

General comments

Actual operating conditions. Pump no. 6163 is one of four vertical pumps that pumps boiling house condenser cooling water back to the spray pond for cooling. Water returns to factory and is then pumped to boiling house evaporators and pans via booster pumps. Three other vertical pumps were operating during the test. Pump flow estimated from 2002 combined flow data. Electrical readings obtained from board readings

This PSAT2004 analysis was printed at 11:04 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No
Speed, rpm	1785
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	250
Existing motor class	Energy efficient
rpm	1775
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.800
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	8000
Head, ft	100.0
Load estimation method	Power
Motor voltage	2410
Motor kW	172.0

	Existing	Optimal
Pump efficiency, %	91.4	90.7
Motor rated power, hp	250	300
Motor shaft power, hp	221.0	222.8
Pump shaft power, hp	221.0	222.8
Motor efficiency, %	95.9	95.8
Motor power factor, %	85.4	83.1
Motor current, amps	48.2	50.0
Motor power, kWe	172.0	173.3
Annual energy, MWhr	1205.4	1214.7
Annual cost, $1,000	180.8	182.2

Annual cost savings potential, $1,000	-1.4
Optimization rating	100.8

Condition B

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No
Speed, rpm	1785
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	250
Existing motor class	Standard efficiency
rpm	1775
Rated voltage	2300
Nameplate FLA	58.5
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.800
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	4500
Head, ft	49.6
Load estimation method	Current
Motor voltage	2410
Motor amps	48.0

	Existing	Optimal
Pump efficiency, %	26.8	88.5
Motor rated power, hp	250	75
Motor shaft power, hp	210.1	63.7
Pump shaft power, hp	210.1	63.7
Motor efficiency, %	94.3	94.7
Motor power factor, %	83.0	84.3
Motor current, amps	48.0	14.3
Motor power, kWe	166.3	50.2
Annual energy, MWhr	1165.1	351.5
Annual cost, $1,000	174.8	52.7

Annual cost savings potential, $1,000	122.0
Optimization rating	30.2

Condition A Notes

Facility Pump 6166 System Factory Vertical Pumps

Application Spray pond recirculation system

Date September 28, 2005 Evaluator Lee Jakeway

General comments

Optimal operating conditions using pump curve data. Pump no. 6166 is one of four vertical pumps that pumps boiling house condenser cooling water back to the spray pond for cooling. Water returns to factory and is then pumped to boiling house evaporators and pans via booster pumps. Three other vertical pumps were operating during the test.

Condition B Notes

Facility Pump 6166 System Factory Vertical Pumps

Application Spray pond recirculation system

Date September 28, 2005 Evaluator Lee Jakeway

General comments

Actual operating conditions. Pump no. 6166 is one of four vertical pumps that pumps boiling house condenser cooling water back to the spray pond for cooling. Water returns to factory and is then pumped to boiling house evaporators and pans via booster pumps. Three other vertical pumps were operating during the test. Pump flow was estimated based on 2002 operating data. Electrical readings were taken from the board.

This PSAT2004 analysis was printed at 11:04 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No (No selected)
Speed, rpm	1785
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	250
Existing motor class	Energy efficient
rpm	1775
Rated voltage	2300
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.800
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	8000
Head, ft	100.0
Load estimation method	Power
Motor voltage	2305
Motor kW	172.0

	Existing	Optimal
Pump efficiency, %	91.4	90.7
Motor rated power, hp	250	300
Motor shaft power, hp	221.0	222.8
Pump shaft power, hp	221.0	222.8
Motor efficiency, %	95.9	95.8
Motor power factor, %	86.2	84.9
Motor current, amps	50.0	51.1
Motor power, kWe	172.0	173.3
Annual energy, MWhr	1205.4	1214.7
Annual cost, $1,000	180.8	182.2

Annual cost savings potential, $1,000	-1.4
Optimization rating	100.8

Condition B

Pump, fluid data — Vertical turbine

Fixed pump specific speed?	Yes / No (No selected)
Speed, rpm	1785
Drive	Direct drive
# stages	1
Specific gravity	1.000
Fluid viscosity (cS)	1.00

Motor ratings

Motor hp	250
Existing motor class	Standard efficiency
rpm	1775
Rated voltage	2300
Nameplate FLA	58.5
Motor size margin, %	15

Duty, cost rate

Operating fraction	0.800
Electricity cost, cents/kwhr	15.000

Required or measured data

Flowrate, gpm	4500
Head, ft	70.4
Load estimation method	Current
Motor voltage	2305
Motor amps	38.0

	Existing	Optimal
Pump efficiency, %	51.8	90.1
Motor rated power, hp	250	125
Motor shaft power, hp	154.3	88.8
Pump shaft power, hp	154.3	88.8
Motor efficiency, %	93.8	95.3
Motor power factor, %	80.9	83.8
Motor current, amps	38.0	20.8
Motor power, kWe	122.7	69.5
Annual energy, MWhr	859.6	486.8
Annual cost, $1,000	128.9	73.0

Annual cost savings potential, $1,000	55.9
Optimization rating	56.6

Condition A Notes

Facility Pump 6168 System Factory Vertical Pumps

Application Spray pond recirculation system

Date September 28, 2005 Evaluator Lee Jakeway

General comments

Optimized conditions using pump curve data. Pump no. 6168 is one of four vertical pumps that pumps boiling house condenser cooling water back to the spray pond for cooling. Water returns to factory and is then pumped to boiling house evaporators and pans via booster pumps. Three other vertical pumps were operating during the test.

Condition B Notes

Facility Pump 6168 System Factory Vertical Pumps

Application Spray pond recirculation system

Date September 28, 2005 Evaluator Lee Jakeway

General comments

Actual operating conditions. Pump no. 6168 is one of four vertical pumps that pumps boiling house condenser cooling water back to the spray pond for cooling. Water returns to factory and is then pumped to boiling house evaporators and pans via booster pumps. Three other vertical pumps were operating during the test. Pump flow estimated and averaged from 2002 flow data.

This PSAT2004 analysis was printed at 11:02 AM on Saturday, January 07, 2006

Condition A

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm: 1185
Drive: Direct drive
stages: 1
Specific gravity: 1.000
Fluid viscosity (cS): 1.00

Motor ratings — Motor hp: 250

Existing motor class: Energy efficient
rpm: 1185
Rated voltage: 2300
Motor size margin, %: 15

Duty, cost rate

Operating fraction: 0.800
Electricity cost, cents/kwhr: 17.600

Required or measured data

Flowrate, gpm: 6500
Head, ft: 110.0
Load estimation method: Power
Motor voltage: 2350
Motor kW: 157.0

	Existing	Optimal
Pump efficiency, %	90.0	90.0
Motor rated power, hp	250	250
Motor shaft power, hp	200.6	200.6
Pump shaft power, hp	200.6	200.6
Motor efficiency, %	95.3	95.3
Motor power factor, %	81.9	81.9
Motor current, amps	47.1	47.1
Motor power, kWe	157.0	156.9
Annual energy, MWhr	1100.3	1099.6
Annual cost, $1,000	193.6	193.5

Annual cost savings potential, $1,000: 0.1
Optimization rating: 99.9

Condition B

Pump, fluid data — End suction ANSI/API

Fixed pump specific speed? Yes / No

Speed, rpm: 1185
Drive: Direct drive
stages: 1
Specific gravity: 1.000
Fluid viscosity (cS): 1.00

Motor ratings — Motor hp: 250

Existing motor class: Standard efficiency
rpm: 1185
Rated voltage: 2300
Nameplate FLA: 59.0
Motor size margin, %: 15

Duty, cost rate

Operating fraction: 0.800
Electricity cost, cents/kwhr: 17.600

Required or measured data

Flowrate, gpm: 4526
Head, ft: 128.9
Load estimation method: Current
Motor voltage: 2350
Motor amps: 49.0

	Existing	Optimal
Pump efficiency, %	70.8	89.2
Motor rated power, hp	250	200
Motor shaft power, hp	208.1	165.3
Pump shaft power, hp	208.1	165.3
Motor efficiency, %	94.3	95.3
Motor power factor, %	82.5	81.9
Motor current, amps	49.0	38.8
Motor power, kWe	164.6	129.4
Annual energy, MWhr	1153.7	906.8
Annual cost, $1,000	203.0	159.6

Annual cost savings potential, $1,000: 43.4
Optimization rating: 78.6

Condition A Notes

Facility: Pump No. 6639
System: Cane Cleaner Pump
Application: Cane Cleaner Pump
Date: September 30, 2005
Evaluator: Lee Jakeway

General comments

Optimal operating conditions assuming pump curve values and increased pump flow for future activity and decreased differential head due to higher vertical pump head as determined from D Christopherson's analysis. This pump supplies wash water to the cane cleaner that comes from the vertical pump system. Head used is from pump curve value ofr 17.5" impeller diameter.

Condition B Notes

Facility: Pump No. 6639
System: Cane Cleaner Pump
Application: Cane Cleaner Pump
Date: September 30, 2005
Evaluator: Lee Jakeway

General comments

Actual operating conditions. This pump supplies wash water to the cane cleaner that comes from the vertical pump system.
Flow reading came from Suite Voyager and electrical readings were obtained from board readings

APPENDIX B

University of Hawaii Reports

Steam Generation Efficiency Assessment
Task 1 Deliverable Report

December 2004

HAWAII NATURAL ENERGY INSTITUTE
School of Ocean and Earth Sciences and Technology
University of Hawaii at Manoa

Steam Generation Efficiency Assessment
Task 1 Deliverable Report

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Prepared for

Hawaiian Commercial & Sugar, Co.
HC&S Purchase Order No. 64137

December 2004

Hawaii Natural Energy Institute
School of Ocean and Earth Sciences and Technology
University of Hawaii

Contents

Abstract

Measurements required to calculate steam generation efficiency were made on three generating units operated by Hawaiian Commercial & Sugar Co. at its Puunene factory in September, 2003, and June, 2004. Tests were conducted on coal and bagasse for all three units and a single test firing fuel oil was conducted in Boiler 3. Measurements of flue gas temperature and composition at the exit of the air preheater were made during each test. Fuel and grate ash were sampled and analyses were performed following the test. Flue gases and temperatures were sampled using probe bundles inserted through access ports in the boiler walls. Each probe bundle was composed of three extraction tubes paired with Type K thermocouples. Boiler 1 was fitted with two probe bundles (a total of six sample extraction locations), whereas Boilers 2 and 3 were fitted with one probe bundle each. Data recorded during the test campaign were later reduced to average values and used to calculate steam generation efficiencies using the energy balance method.

Flue gas temperatures at the exit of the air preheater of the three boilers ranged from 180 to 248ºC. The lowest exit temperature was recorded for Boiler 3 during the fuel oil test. When bagasse and coal were fired, Boiler 1 had the lowest exit temperature and Boilers 2 and 3 were consistently higher by 15 and ~30ºC, respectively. Exit temperatures of all boilers were higher when bagasse was fired, ranging from 220 to 248ºC compared to 189 to 219ºC for coal.

Gas composition measurements made after the air preheater showed carbon monoxide concentrations to be highly dependent on fuel type. Fossil fuels produced relatively low CO concentrations in the range of 10 to 90 ppmv. Bagasse tests exhibited elevated CO concentrations with averages ranging from 1,300 to 3,200 ppmv.

Excess air values calculated for coal tests ranged from 46% for Boiler 3, to 101% and 128% for Boilers 1 and 2, respectively. Excess air values calculated for Boilers 1, 2, and 3 operating on bagasse were 57, 58, and 17%, respectively. The excess air value calculated for Boiler 3 using fuel oil was 99%.

Calculated efficiencies for Boilers 1, 2, and 3 firing coal were 80.8, 76.1, and 82.4%, respectively. Higher excess air values and flue gas exit temperatures were the main factors contributing to the lower efficiency of Boiler 2 compared to the other two units.

Calculated efficiencies for Boilers 1, 2, and 3 firing bagasse were 65.9, 63.2, and 67.2%, respectively, markedly lower than those determined for coal. Boiler 2's lower efficiency resulted from higher flue gas temperature and CO concentrations than the other two units. Lower efficiencies observed when firing bagasse compared to coal are largely due to the different moisture contents of the two fuels, 48% for bagasse and 6 to 10% for coal.

Several opportunities to improve boiler efficiency are evident from the results of the test campaign. Reducing excess air, flue gas CO concentrations, and flue gas exit temperature all can contribute to increased efficiency, although the first two items may be more easily addressed in the near term. It is recognized that the ability to respond to these opportunities may largely be

determined by the physical limitations of the boiler system's equipment and the constraints imposed by operating the units in conjunction with the Puunene sugar factory.

Potential cost savings from improvements in boiler efficiency were calculated. When all three steam generating units fire coal, a 1% increase in efficiency in each of the three boilers would result in a savings of 9.5 tons of coal per day with an associated cost savings of $620 per day. Similarly, when all three units fire bagasse, a 1% improvement in efficiency would save 21.5 tons fuel (dry basis) per day and result in a cost savings of $750 per day.

1. Introduction

Increasing competition from abroad and lower prices for sugar and sugar products has taken its toll on the sugar industry in Hawaii. The challenges facing the remaining local producers are more formidable than ever. The increasing cost of energy has been added to these already strenuous challenges. To remain competitive and profitable in today's market it is imperative that Hawaii sugar producers use the most energy efficient production methods and run the most energy efficient processing facilities possible.

Hawaii's largest remaining sugar producer, Hawaiian Commercial & Sugar Co. (HC&S), has undertaken a plantation wide energy efficiency assessment with cost share from the U.S. Department of Energy's (DOE) Office of Industrial Technology (OIT). This assessment includes analyses of the irrigation pumping systems, electrical distribution system, and sugar factory. The sugar factory assessment is composed of two parts, a boiler efficiency assessment for the cogeneration plant and a steam use assessment for the entire factory including the mill, processing plant, and cogeneration plant. The University of Hawaii (UH) was contracted to provide technical assistance on the boiler efficiency and steam assessment portions of the project. This report summarizes work completed by UH on the steam generator efficiency portion of the factory assessment.

HC&S has three steam generation units at its Puunene sugar factory. All three are grate-fired, stoker-type units. Boilers 1 and 2 are identical and operate at 900 psi steam pressure and each has a rated capacity of 120 klb steam hr^{-1}. Flue gases from the two units are exhausted through a common wet scrubber and stack. Residue from their grates enters a common water quench and is removed by a belt conveyor. Boiler 3 operates at 425 psi steam pressure and is rated for 290 klb steam hr^{-1}. Flue gas from Boiler 3 is exhausted through a dedicated wet scrubber and stack and the grate residue is also removed using a dedicated water quench and conveyor system.

The two generally accepted methods of determining steam generator efficiency are detailed in ASME PTC 4-1998 Fired Steam Generators Performance Test Codes [1] and are referred to as the input/output (or direct) method and the energy balance (or indirect) method, respectively. The direct method requires highly accurate measurement of all input and output flows, while the indirect method requires identification and determination of all losses.

The direct method requires measurement of fuel and steam flow rates, moisture content, fuel higher heating value, steam temperature and steam pressure. The effectiveness of the direct method is strongly dependent on the accurate measurement of the fuel flow rate, moisture content, and higher heating value. Steam temperature and pressure measurements have a weaker affect on the overall accuracy of the efficiency calculation.

The indirect method requires measurement of fuel higher heating value, moisture content, and ultimate analysis and flue gas exit temperature and composition. Unburned carbon losses must also be determined. Radiation losses and unaccounted losses must also be measured or calculated using manufacturer's specifications. The effectiveness of the indirect method is strongly dependent on the fuel higher heating value and the moisture content determination. Total accuracy is also moderately dependant on the ultimate analysis and flue gas exit temperature and composition. Losses estimated from manufacturer's specifications have a small effect on the accuracy of the overall efficiency determination [2].

Bagasse is the primary fuel used in all three boilers at HC&S. Bagasse is a bulky fuel and, as such, is difficult to accurately meter, thus favoring the indirect method for determining boiler efficiency. The ASME test code [1] also recommends using the indirect method since it provides lower overall test uncertainty and can be corrected to standard or guarantee conditions. For these reasons the indirect method was chosen for this assessment.

HC&S must conduct emission compliance tests on a yearly basis. During these tests the factory and boiler system are operated as steadily as possible and at, or near, full capacity. The steam generator efficiency assessments were schedule at the same time as the compliance tests to take advantage of this period of steady operation and the fuel analyses performed as part of the compliance determination.

2. Materials and Methods

2.1 Test Equipment

In advance of the test campaign, the UH project team made several trips to set up measurement sites on each of the HC&S boilers. ASME's test code indicates that measurement of flue gas composition and temperature for calculation of boiler efficiency using the indirect method should be made immediately following the last heat recovery device. In the case of HC&S boilers this point is located after the air preheater. ASME's test code suggests a sample matrix of 16 points, evenly spaced throughout the duct. Due to equipment and time limitations, and physical constraints, sampling at 16 points was not feasible.

Upon reviewing available access to the ducts following the air preheaters on Boilers 1, 2, and 3, it became clear that the sampling matrix would have to be scaled back. Boiler 1 had two accessible ports and Boilers 2 and 3 each had one accessible port. Prior to testing, each port was fitted with three stainless steel sample extraction tubes (ID=11.8 mm=0.465", OD=12.7 mm=0.50") welded together to form a triangular probe bundle. The tubes were cut to different lengths and protruded into the flue gas flow with inlets located 2, 4, and 6 ft (0.61, 1.22, and 1.83 m) from the duct wall. Type K thermocouples were attached to each of the three tubes in the probe bundle to provide companion temperature readings at each inlet location. The tube bundle and thermocouple assembly was fitted through a 2" (50.8 mm) pipe cap that could be attached to ports located on the boiler wall. A diagram of the probe assembly is shown below in Figure 1. Figures 2 and 3 provide schematics of the probe sampling locations in the duct cross sections immediately following the air preheater for each boiler. Figure 4 presents a schematic of Boiler 1 indicating the sampling location and this is also representative of Boilers 2 and 3.

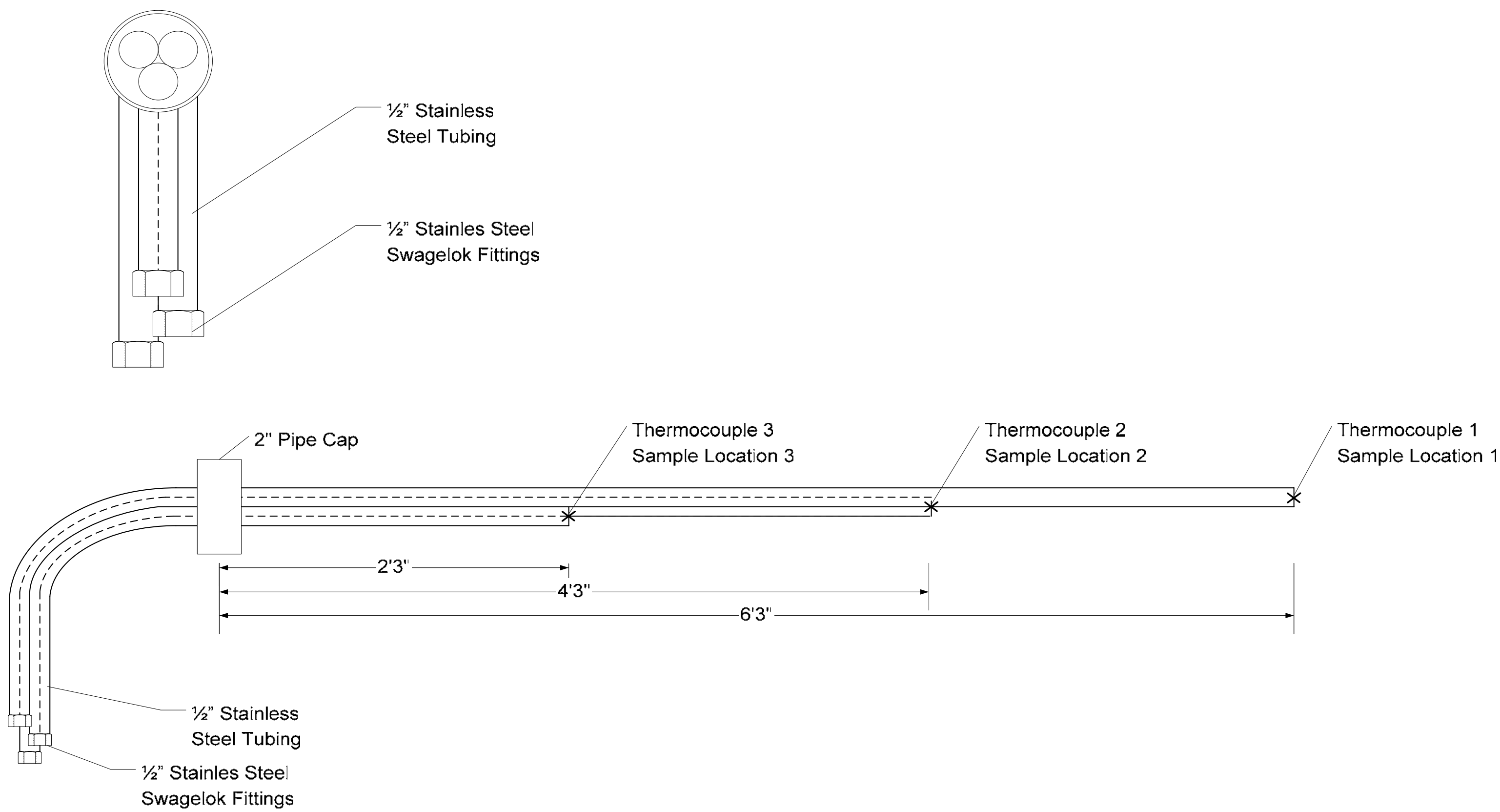
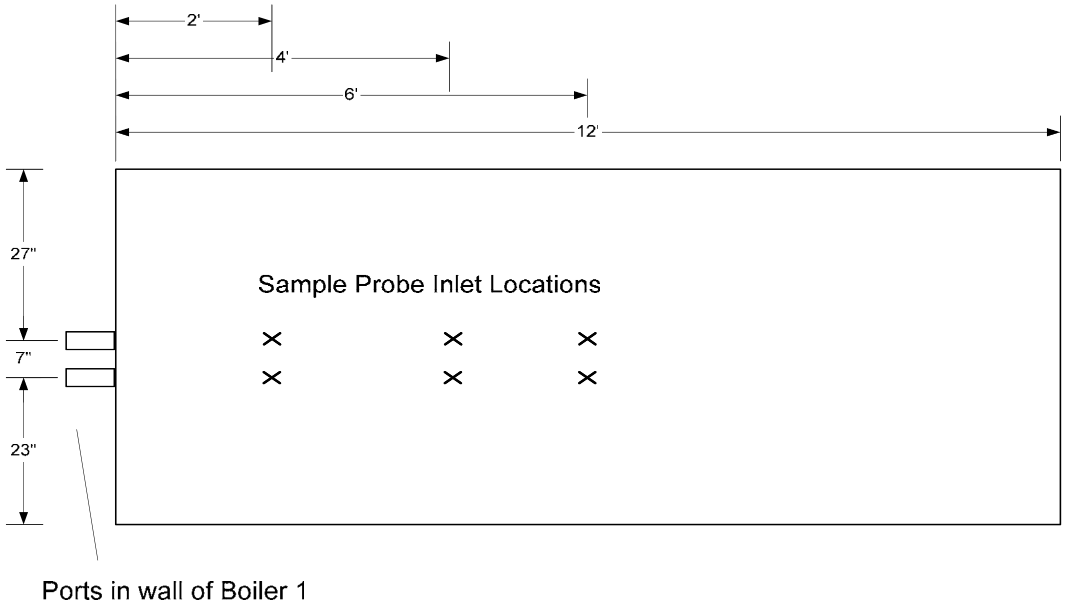
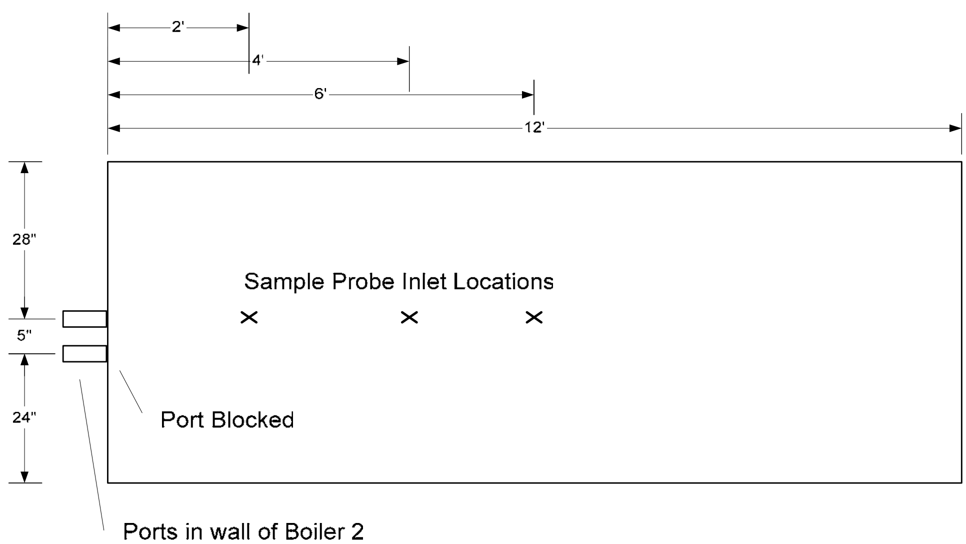


Figure 1. Schematic of probe bundle containing three stainless steel sample extraction tubes and thermocouple assemblies.



(a)



(b)

Figure 2. Cross sectional of duct downstream of the air preheater showing port and sample probe inlet locations. Boiler 1 is shown in (a) and Boiler 2 is shown in (b).

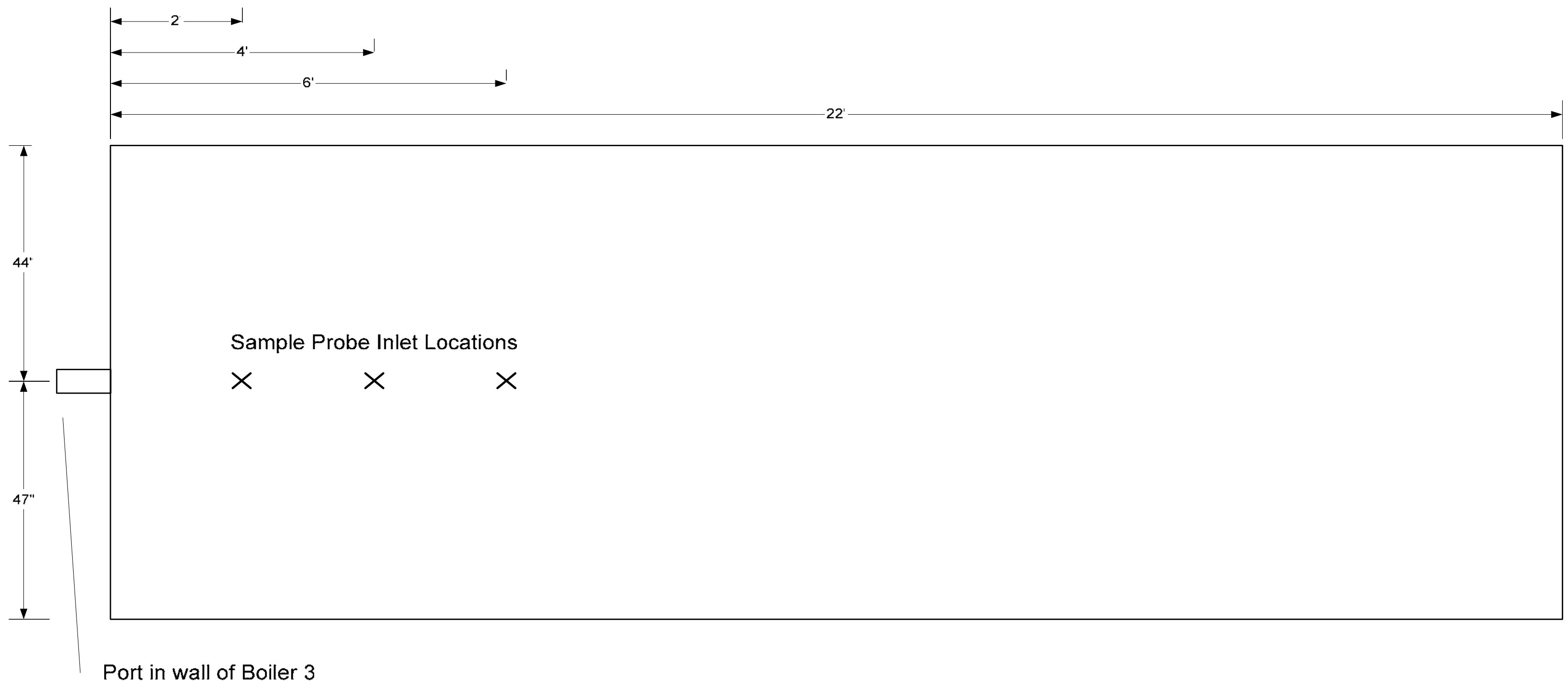


Figure 3. Cross sectional of duct in Boiler 3 downstream of the air preheater showing port and sample probe inlet locations.

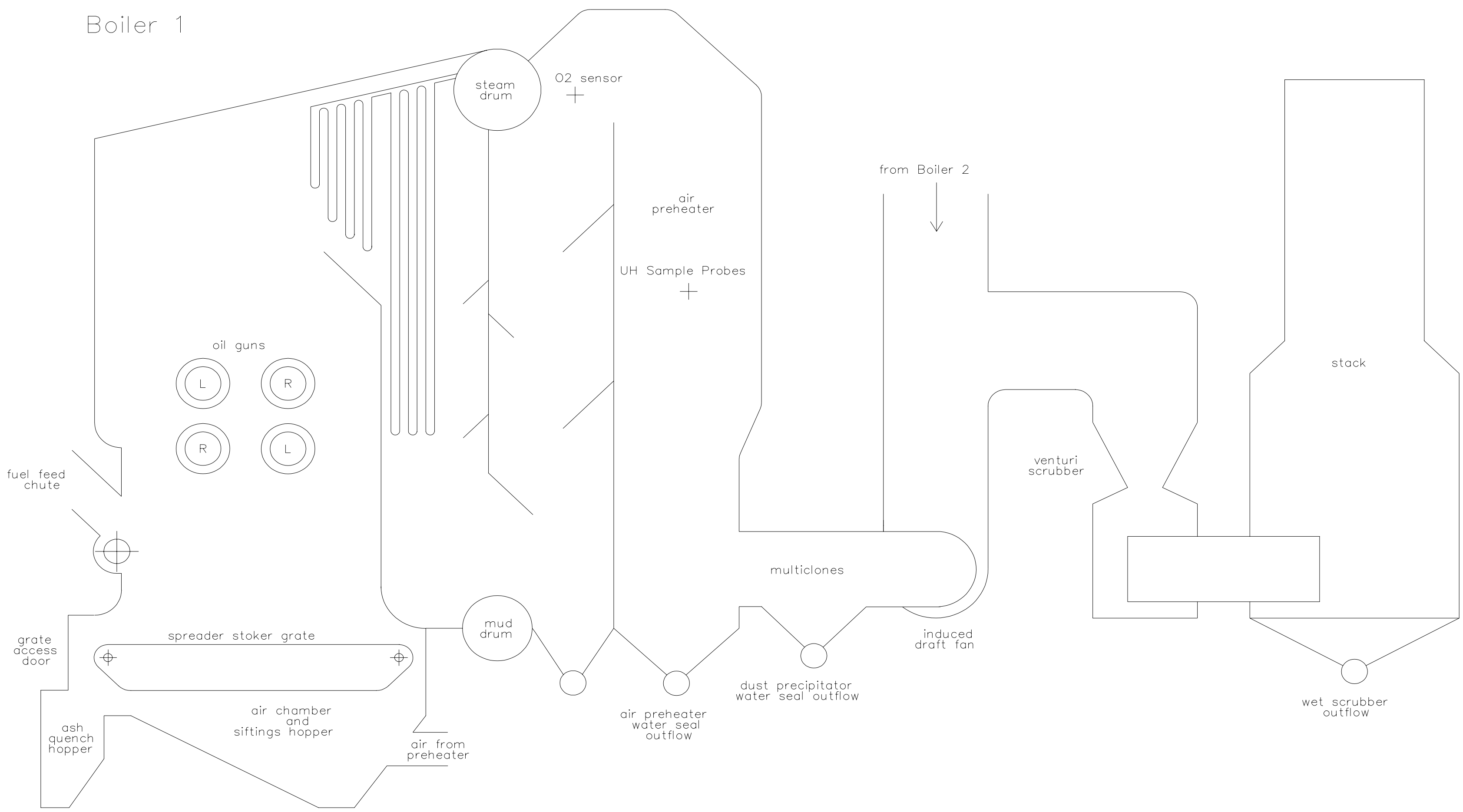


Figure 4. Schematic of Boiler 1 showing UH sample probe location after the air preheater.

External to the boiler, the sample extraction tubes were bent 90º and terminated with Swagelok fittings. The 90º degree bend reduced the potential for kinks in the flexible sample tubes used between the probe and the sampling system. Three 20' (6.1 m) lengths of 0.5" (12.7 mm) diameter, Teflon tubing were bundled together and attached to the sample extraction tubes. The sample lines allowed sensitive gas monitoring equipment and the sampling system to be located in a milder and more accessible environment than that found near the boiler walls.

In order to remove entrained particulate matter and water vapor from extracted flue gas, the sample stream was directed through a set of four impingers immersed in an ice bath and a silica gel desiccant bed. Particulate matter removal and dehumidification was necessary to ensure safe operation of down stream components; a diaphragm pump, a volumetric flow meter, and a portable gas analyzer (Horiba, Model PG-250). Flue gas was drawn through one sample extraction tube at a time and directed through the impinger system to remove particulate matter and condense water vapor. The cooled gas then passed through the desiccant bed, the diaphragm pump, and the volumetric flow meter before being exhausted to atmosphere, as shown in Figure 5. A slip stream of the cool dry gas drawn from the flow between the volumetric flow meter and exhaust was directed to the portable gas analyzer.

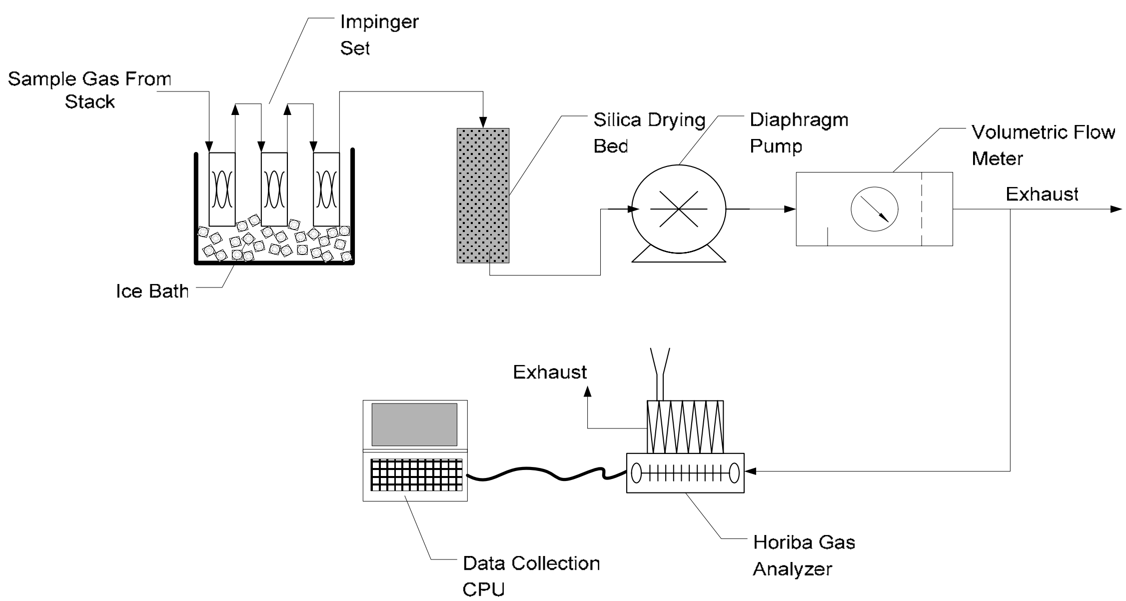


Figure 5. Sampling conditioning system used for analysis of flue gases downstream of the air preheater.

The Horiba PG-250 gas analyzer measures NOx, CO, CO_2, SO_x, and O_2. Ranges for these gases are 0 to 25/50/100/250/500/1000/2500 ppm for NO_x, 0 to 200/500/1000/3000/5000 ppm for SO_x, 0 to 200/500/1000/2000/5000 ppm for CO, 0 to 5/10/20 vol % for CO_2 and 0 to 5/10/25 vol % for O_2. For coal and fuel oil tests the 0-500 ppm range for CO was selected. The 0-5000 ppm range for CO was selected for bagasse-fired tests. All calibration standards for the project were purchased from Matheson Trigas and had accuracy of ±2%. The composition of each calibration standard is listed in Table 1.

Table 1. Gases used to calibrate the Horiba PG-250 gas analyzer

Calibration Gas	Concentration (volume basis)	Balance Gas
O_2	21%	N_2
CO_2	12.5%	N_2
CO	500 ppm	N_2
CO	5000 ppm	N_2
SO_x	250 ppm	N_2
NO_x	250 ppm	N_2
N_2	100%	None

Data from the Horiba were saved to a laptop computer running Horiba proprietary software and individual data points were recorded on a 5 s sampling interval.

Temperature data from the three Type K thermocouples (Omega Engineering, Stanford, CT) on the active probe bundle were sampled on 5 second intervals and recorded on a data logger (Campbell Scientific, Model 23X, Logan, UT).

2.2 Sampling and Data Collection

Efficiency assessment testing was scheduled for the week of September 22-27, 2003. Tests took place on Boiler 1 and 2 on September 22-23 and on Boiler 3 on September 25-27. September 24th was used to move emission monitoring equipment between stacks. Flue gas composition data for the coal test on Boiler 2 was lost during the test campaign and a make-up test was completed on June 29, 2004. Although the June 29 test was not conducted in conjunction with a compliance test, test conditions were maintained as close to those of the September test as possible.

The compliance testing schedule called for one fuel to be tested on one of the stacks each day. Sampling equipment was assembled on location at the beginning of each day. Start up protocol for the Horiba analyzer includes a one hour warm up period after powering up the unit. This was followed by a daily leak check and calibration sequence.

Flue gas sampling was initiated after the gas analyzer calibration routine was completed and when system operators indicated that steady boiler operations had been attained. A minimum of three, 10 minute samples were drawn from each of the three extraction tubes in each probe bundle. To change the sampling point, sample lines were exchanged at the connection to the impinger set. Lines were capped when not in use. Sample gas flow rate was maintained in the range of 12 to 15 L min^{-1} (0.42 to 0.53 scfm).

For the September 2003 tests, three fuel and grate residue samples were collected per compliance test by HC&S staff. Grate residue samples were collected only for the coal tests. Grate residues from Boilers 1 and 2 are commingled in a water quench and a single composite residue sample was obtained from the drag conveyor outfall. Bagasse residue is entrained in the flue gases and removed in the air pollution control equipment downstream and no residues were generated when firing fuel oil. Solid fuel samples were subjected to moisture, proximate, ultimate, and heating value analyses. Fuel oil samples were subjected only to moisture and the latter two analyses. Grate ash samples were subjected to moisture, total and organic carbon, combustibles, and loss on ignition. All samples were analyzed by Standard Laboratories Inc., Casper, Wyoming.

For the June 29 coal make-up test, University of Hawaii personnel collected fuel and grate residue samples for analysis. Samples from this test were subjected to the same battery of analyses, however the analyses were performed by Hazen Research, Golden, Colorado.

Data from sensors HC&S uses to monitor and control the power plant are acquired, recorded, and managed using Wonderware software. Data from the week of the test campaign were requested and received from HC&S personnel as one-minute averages for each boiler. Quantities included steam flow rates, temperatures, and pressures; steam blow down flow rates; boiler feedwater flow rates and temperatures; indicators of combustion air flow to grate locations and windboxes; indicators of induced draft, forced draft, and overfire air flows; fuel oil, bagasse, and coal flow rates; flue gas O_2 concentrations; steam drum and header pressures; air preheater performance data; grate temperatures; and wet scrubber water flow rates.

2.3 Data Reduction

Averages and standard deviations were computed from the data collected at each of the flue gas sampling locations. A composite average and standard deviation of flue gas properties for each boiler operating on a given fuel were calculated from the individual sampling location averages. Results from analysis of the triplicate fuel and grate residue samples were averaged to produce a composite average for each boiler on each fuel.

3. Results and Discussion

3.1 Fuel Analyses

Average results of the fuel and grate ash analyses pertinent to efficiency calculations are summarized in Table 2. Lab reports of analyses for individual samples are presented in Appendix A. Consistency is generally good between samples of the same material acquired on different days. Results of the coal samples (06/29/04) analyzed by Hazen Research show slightly higher values for ash, volatile matter, higher heating value, C, and S, than results of the earlier coal analyses performed by Standard Laboratories. It is not apparent whether this is due to actual differences in the fuel, or rather the result of differences in analytical technique between the two laboratories. Coal moisture contents ranged from 6.6 to 10.7% wet basis. The higher value was recorded for the 9/26/03 test and was the result of rain on 9/23 and 9/24/03. Bagasse moisture was consistently ~48% wet basis over all tests.

Table 2. Average properties of fuels used, and residues generated, during the efficiency assessment test periods.

	Coal Test 09-22-03	Bagasse Test 09-23-03	Bagasse Test 09-25-03	Coal Test 09-26-03	Fuel Oil (Bunker C) 09-27-03	Coal Test 06-29-04
Boiler(s)	1&2	1&2	3	3	3	2
Fuel Analyses						
No. of Analyses	3	3	3	3	3	3
Moisture Content (% wet basis)	6.6±0.04	48.1±0.7	47.8±1.7	10.7±.1	0±0	6.8±0.9
Proximate Analysis (% dry basis)						
Ash	13.12±0.12	1.84±0.29	1.78±.26	13.55±0.05	0.00±0.00	14.64±0.60
Volatiles	41.06±0.25	80.81±0.34	80.78±0.31	41.25±0.14		43.88±1.40
Fixed C	45.82±0.23	17.35±0.23	17.43±0.10	45.2±0.10		41.48±1.36
Higher Heating Value (dry basis)						
MJ/kg	29.0±0.11	19.0±0.15	19.1±0.17	28.9±0.07	45.7±0.1	29.6±0.19
BTU/lb	12,476±46	8,167±64	8,194±72	12,437±32	19,640±27	12,725±83
Ultimate Analysis (% dry basis)						
C	70.15±0.16	49.54±0.21	49.58±0.22	69.71±0.18	86.46±0.41	70.87±0.81
H	5.43±0.02	5.69±0.05	5.71±0.05	5.39±0.07	11.70±0.53	5.36±0.16
O (by difference)[c]	9.74±0.04	42.66±0.25	42.73±0.08	9.78±0.20	1.64±0.39	7.48±0.70
N	1.08±0.02	0.16±0.03	0.13±0.03	1.07±0.01	0.02±0.02	1.11±0.03
S	0.48±0.01	0.11±0.03	0.08±0.01	0.49±0.01	0.18±0.02	0.54±0.01
Residue Analysis						
Number of Analyses	3			3		3
Organic Carbon (% dry basis)	2.58±0.46			3.63±1.10		7.44±0.75

3.2 Boiler Efficiency

Table 3 summarizes the boiler efficiency data from the test campaign. The upper half of the table presents average values of relevant measured quantities. The averages from which the data in Table 3 were derived are presented in Appendix B. Plots of output from the Horiba gas analyzer and the Type K thermocouples for each of the tests are compiled in Appendix C. The lower half of Table 3 presents data that were derived from the fuel properties and measured quantities

Data from the HC&S Wonderware system is presented as graphs, for reference, in Appendix D.

3.2.1 Measured Quantities

Flue gas temperatures at the exit of the air preheater of the three boilers ranged from 180 to 248ºC. The lowest exit temperature was recorded for Boiler 3 during the fuel oil test. When bagasse and coal were fired, Boiler 1 had the lowest exit temperature and Boilers 2 and 3 were consistently higher by 15 and ~30ºC, respectively. Exit temperatures of all boilers were higher when bagasse was fired, ranging from 220 to 248ºC compared to 189 to 219ºC for coal. (Note: Flue gas temperatures in degrees Fahrenheit are shown in the lower half of Table 3). For comparison, various historical temperature values (either predicted or measured) provided by the boiler manufacturer are summarized in Table 4. The acceptance test report prepared by Riley Stoker Corporation in 1956 when Boiler 1 was commissioned on bagasse indicates that at a steam flow of 66.8 Mg per hour (147,000 lb per hr), the exit temperature at the air preheater was 224ºC. Similarly, Boiler 3 performance tests conducted by Foster Wheeler in 1978 using bagasse reported an air preheater exit temperature of 224ºC at a steam flow rate of 131.1 Mg per hour (289,000 lb per hr), a flow rate most comparable to the current test condition. From these data it can be concluded that the air preheater exit temperature of Boiler 1 is comparable to the value measured at the time of commissioning, but that values for Boilers 2 and 3 are roughly 15 to 25ºC above values determined by the original equipment manufacturer.

Measurements of gas composition made after the air preheater found carbon monoxide concentrations to be highly dependent on fuel type. Fossil fuels produced relatively low CO concentrations in the range of 10 to 90 ppmv. Bagasse tests exhibited elevated CO concentrations with averages ranging from 1,300 to 3,200 ppmv. The averages for bagasse are necessarily underestimates of the true average value as CO concentration exceeded the maximum value on the 0 to 5,000 ppmv range of the gas analyzer on several occasions, producing an over range marker in the data file. Over range markers were replaced with values of 5,114 ppmv (maximum value for the 0 to 5,000 range before over range value is issued) so that an average could be computed.

Table 3 also includes flue gas O_2 concentrations with values ranging from 3 to 12%. Boilers 1 and 2 firing coal had values at the upper end of this range and both averaged ~7.7% O_2 when fueled with bagasse. Boiler 3 exhibited the lowest average O_2 concentration of 3.0% while operating on bagasse and this correlates with the high CO concentration (3200 ppmv) reported in the previous paragraph. Boiler 3 operating on coal and fuel oil produced flue gas O_2 concentrations of ~7%. A comparison of the O_2 concentrations measured by the Horiba and those recorded by the HC&S Wonderware system from the O_2 sensor installed in each boiler for monitoring and control purposes is shown in Figure 6. Differences (% O_2, absolute) between the two measuring devices at their respective locations ranged from 3.4 to 4.6% for Boiler 1, 5.7 to 9.3% for Boiler 2, and 0.3 to 2.0% for Boiler 3. Differences may be the result of calibration or air ingress in the ducting between the upstream HC&S O_2 sensor and the downstream UH sampling location at the outlet of the air preheater. The two measurement locations on Boiler 1 are shown in Figure 4 and are representative of other two boilers.

NO_x concentrations ranged from 50 to 227 ppmv with values generally correlating with fuel nitrogen content (fuel oil<bagasse<coal).

Table 3. Averages of relevant measured and derived quantities from boiler efficiency tests at HC&S.

Boiler No.	1	1	2	2	3	3	3
Test Date	9/22/03	9/23/03	6/29/04	9/23/03	9/25/03	9/26/03	9/27/03
Fuel	Coal	Bagasse	Coal	Bagasse	Bagasse	Coal	#2 Fuel Oil
Average Steam Flow Rate, klb/hr (from HC&S Wonderware system)	105.9±4.5	104.2±3.8	104.0±8.6	105.3±3.8	259.7±19.4	266.8±5.2	241.8±6.5
Measured Quantities[1]							
Fuel Moisture Content, % wet basis	6.6±0.04	48.1±0.7	6.8±0.9	48.1±0.7	47.8±1.7	10.7±0.1	0.0±0.0
Flue Gas Air Preheater Exit Temperature, C	189±6	220±8	219±8	248±15	235±25	204±16	180±11
Flue Gas CO Concentration, ppmv	83±11	1311±758[2]	87±23	2696±1368[2]	3156±1546[2]	10±3	26±26
Flue Gas O_2 Concentration, % vol	10.7±1.4	7.6±1.9	11.9±1.5	7.7±2.5	3.0±1.4	6.8±0.6	10.7±1.4
Flue Gas NO_x Concentration, ppmv	127±20	78±15	180±31	82±18	119±18	227±29	55±10
Total Organic Carbon Content of Grate Residue [3], %	2.6±0.46		7.4±0.75			3.6±1.10	
Derived Quantities							
Flue Gas Air Preheater Exit Temperature, F	372	429	426	479	455	400	357
Flue Gas CO Concentration, % vol	0.008	0.131	0.009	0.270	0.316	0.001	0.003
Excess Air, %	101	57	128	58	17	46	99
Fuel Efficiency, Indirect Method, Uncorrected for Losses, %	83.3	68.5	79.6	66.5	70.3	85.0	84.0
Efficiency Correction, Loss from Total Organic	0.40		1.34			0.60	
Efficiency Correction, Loss from CO in the Flue Gas, %	0.05	0.61	0.13	1.27	1.10	0.00	0.01
Efficiency Correction, Loss from Surface Radiation [4], %	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Efficiency Correction, Manufacturers Unaccounted for Losses [4], %	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Fuel Efficiency, Indirect Method, Corrected for Losses, %	80.8	65.9	76.1	63.2	67.2	82.4	82.0

[1] Error values equal to one standard deviation.
[2] Measured values exceeded instrument range, over range values replaced with 5,114 ppmv to calculate average and standard deviation
[3] Grate residue samples collected from tests using coal
[4] Based on past study of Puunene Boiler 3 conducted by Foster Wheeler in 1978 [4].

Table 4. Historical original equipment manufacturer (OEM) air preheater exit gas temperature values by measurement and prediction

Unit	Fuel	Steam Flow Rate (klbs/hr)	T (F)	T (C)	Data Source[1]
Boiler 1	Baggase	147.2	436	224	1
Boiler 1	Oil	186.9	420	216	1
Boiler 3	Oil	290.0	333	167	2
Boiler 3	Oil	319.0	344	173	2
Boiler 3	Bagasse	145.0	353	178	3
Boiler 3	Bagasse	217.5	395	202	3
Boiler 3	Bagasse	289.0	436	224	3
Boiler 3	Bagasse	319.0	453	234	3
Boiler 3	Bagasse	290.0	423	217	2
Boiler 3	Bagasse	319.0	447	231	2

[1] 1 indicates data from Riley Stoker acceptance test report [5]
2 indicates data from Foster Wheeler engineering prediction report [6]
3 indicates data from Foster Wheeler performance test report [7]

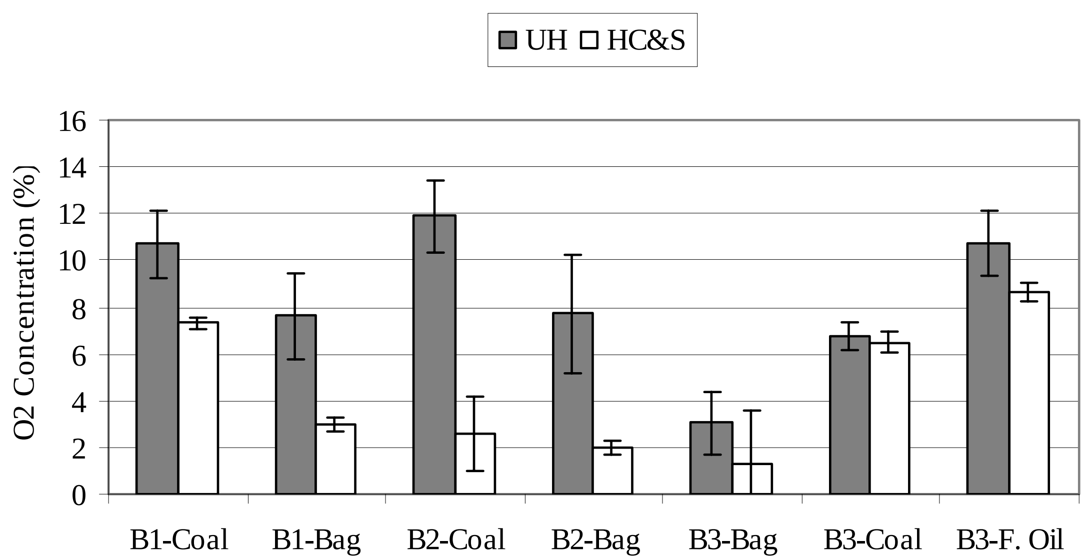


Figure 6. Comparison of average flue gas O_2 concentrations recorded by the Horiba gas analyzer down stream of the air preheater and the O_2 sensor installed in each boiler for monitoring and control purposes. B# indicates boiler number. Coal, Bag, and F. Oil indicate that coal, bagasse, and fuel oil were fired during the measurement.

Results of the analysis of organic carbon concentrations in the grate residues are also presented in Table 3. It was assumed that firing fuel oil results in no residues and therefore no carbon losses. As noted in the previous section, grate samples were collected only from tests using coal since residues from bagasse were entrained from the grate and removed in the pollution control devices down stream. Carbon lost in this manner was not quantified in the present work. In co-firing tests conducted at HC&S in 2002, samples were collected from the air preheater and dust precipitator water seal and wet scrubber effluents from Boiler 1 fired with a mixture of 25% coal, 13% fuel oil, and 62% bagasse. Analysis showed that the dust precipitator and wet scrubber removed large amounts of particulate matter that was composed of ~90% ash, indicating that the maximum organic carbon content of particulate matter would be ~10% by difference. If measured, organic carbon content could be expected to be smaller than 10% since the combustible fraction contains other species. For example, the analysis of the grate residues collected from the current coal fired efficiency tests show that the organic carbon as a fraction of total combustibles ranges from 15 to 40%. Based on this we can estimate that the organic carbon content of the particulate matter removed in the pollution control devices would be on the order of 5% and could be expected to reduce boiler efficiency accordingly, roughly in the range 0.1 to 0.2%.

3.2.2 Derived Quantities

Excess air values reported in Table 3 were derived using the flue gas O_2 concentration, the fuel composition, and chemical stoichiometry. Excess air is necessary to improve fuel conversion but too much contributes unnecessary thermal mass and increases air and flue gas handling requirements. Values calculated for coal ranged from 46% for Boiler 3, to 101% and 128% for Boilers 1 and 2, respectively. An excess air range of 30 to 60% is recommended for spreader stokers firing coal [3]. Similarly the value of excess air for all bagasse-fired units is recommended to be 25 to 35% [3]. Excess air values calculated for Boilers 1, 2, and 3 operating on bagasse were 57, 58, and 17%, respectively. Excess air values for fuel oil fired from register-type burners are recommended to be in a range of 5 to10% [3]; the value calculated for Boiler 3 using fuel oil was 99%.

Results of efficiency calculations using the indirect method are presented in Table 3. Uncorrected values were calculated based on the O_2 concentration and temperature of flue gas at the air preheater exit temperature and the fuel elemental composition and heating value. These values are corrected for losses in efficiency associated with organic carbon in the grate residue, carbon monoxide in the flue gas, surface radiation, and manufacturer's unaccounted for losses. Where appropriate, values for each of these losses are presented in Table 3. Assumed values for surface radiation losses and manufacturer's unaccounted for losses are based on values from past performance evaluations. Final boiler efficiencies are presented at the bottom of the table.

Calculated efficiencies for coal for Boilers 1, 2, and 3 were 80.8, 76.1, and 82.4%, respectively. Several factors contributed to the lower efficiency of Boiler 2 when compared to the other two units. For the coal tests, Boiler 2 had the highest flue gas exit temperature and largest amount of excess air. The organic carbon content of the grate residue collected during testing of Boiler 2 was also higher than that from the other boiler tests. While this contributes to the lower boiler efficiency value, it is recognized that samples are mixtures of grate residues from Boilers 1 and 2, and Boiler 2 may not be wholly responsible for the elevated organic carbon content. CO in the flue gases from the three boilers ranged from 10 to 87 ppmv and values for Boilers 1 and 2 were at the upper end of this range.

Calculated efficiencies for Boilers 1, 2, and 3 firing bagasse were 65.9, 63.2, and 67.2%, respectively, markedly lower than those determined for coal. The ranking of boilers in the order of decreasing efficiency was the same as with coal (Blr 3>Blr 1>Blr 2). In addition, the relative differences between units were also consistent for both fuels. Boiler 1 was ~2% (relative) lower than Boiler 3 and Boiler 2 was ~7% (relative) lower than Boiler 3. The ranking of the boilers with regard to excess air (Blr 2>Blr 1>Blr 3) and exit temperature (Blr 2>Blr 3>Blr 1) followed the same order as those found for coal and these parameters are largely responsible for the differences in efficiency when comparing boilers fired on the same fuel. The elevated carbon monoxide levels when firing bagasse also reduced efficiency, with losses ranging from 0.62 to 1.29%.

All three of the boilers exhibited similar reductions in efficiency when operated on bagasse relative to coal, becoming 17 to 18.5% (relative) less efficient. This can be attributed largely to the greater moisture content of bagasse, 48% compared to 6 to 10% for coal.

Boiler 3 was the only unit tested on No. 2 fuel oil and calculated efficiency was 82.0%.

Sensitivity calculations were performed to provide an indication of the efficiency increases that could result from reductions in excess air or the flue gas temperature at the preheater exit. Results are presented in Figure 7. Boiler 2 fueled with coal had the highest excess air measured during the test campaign at 128%. Reducing the excess air from 128 to 45% (by decreasing the flue gas O_2 concentration used in the calculation from 11.9 to 6.6%) increased boiler efficiency from 76.1 to 81.4%. Similarly, the highest average air preheater exit temperature, 248ºC, was recorded on Boiler 2 fueled with bagasse. Changing only the value of the exit temperature from 248 to 220ºC (428ºF) resulted in an increase in boiler efficiency from 63.2 to 65.1%. Reducing CO in the flue gas and the organic carbon content of grate residues also will result in efficiency improvements. The calculated losses in efficiency from each are presented in Table 3 and provide upper limits to possible efficiency increases.

Boiler efficiency is defined as the energy embodied in the steam flowing out of the boiler, divided by the energy contained in the fuel flowing into the boiler at steady state. Potential savings from incremental improvements in boiler efficiency can be calculated by (1) holding the fuel flow rate constant, increasing the efficiency value, and then calculating the increased steam flow rate, or (2) holding the steam flow rate constant, increasing the efficiency value, and then calculating the decreased fuel flow rate. The former method was used to calculate fuel savings that could be expected from a 1% improvement in boiler efficiency for each of the steam generating units.

The results of these calculations are presented in Table 5. In addition, associated savings were estimated using fuel unit costs provided by HC&S and are included in Table 5. A 1% improvement in operating efficiency using coal in Boilers 1 and 2 would save 4.3 tons coal (dry basis) per day. Similarly, a 1% improvement in efficiency for Boiler 3 operating on coal would result in savings of 5.2 tons coal (dry basis) per day. At a coal unit cost of $65.22 per ton, this would result in direct fuel savings worth $620 per day when all three boilers fired coal.

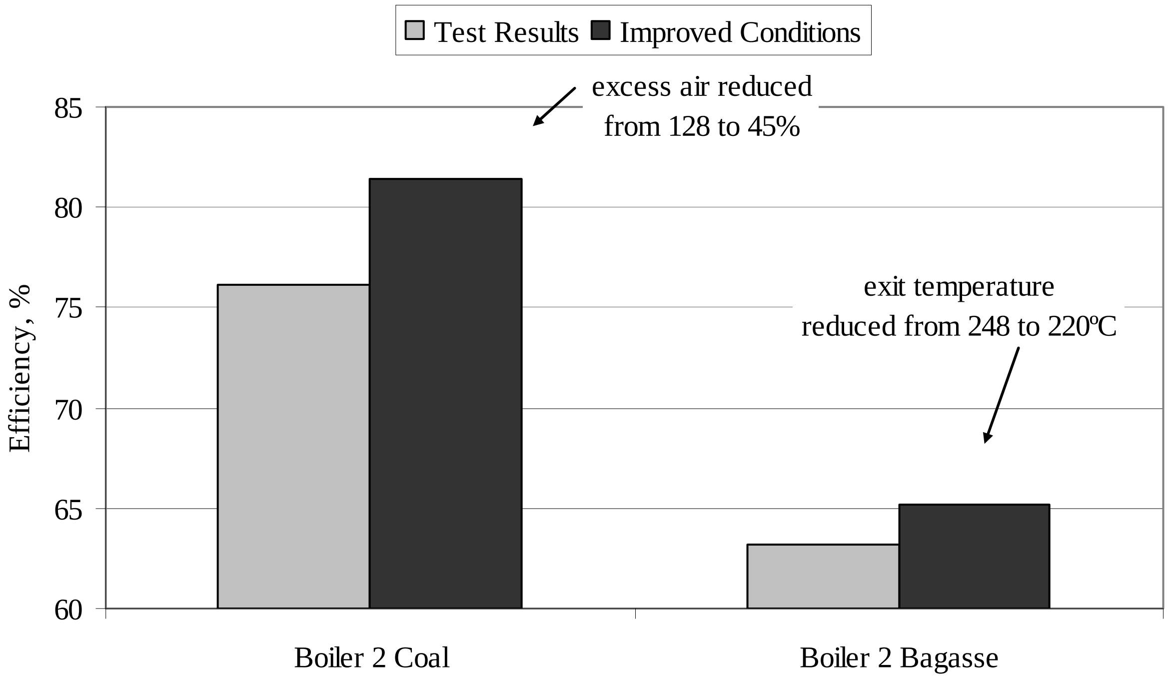


Figure 7. Sensitivity of boiler efficiency calculations to changes in values of excess air and flue gas temperature at the exit of the air preheater.

If all three boilers fire bagasse, a 1% improvement in efficiency would save 21.5 tons (dry basis) per day. A value for bagasse, $34.78 per ton (dry basis), was calculated based on the price of coal, the heating values of the two fuels, and the average boiler efficiencies for the two fuels. The latter was weighted based on steam flow. i.e. since Boiler 3 produces more steam it would contribute more to the average. The 21.5 tons of bagasse saved by efficiency improvements would result in a cost savings of ~$750 per day.

4. Summary and Conclusions

Measurements required to calculate steam generation efficiency were made on three generating units operated by Hawaiian Commercial & Sugar Co. at its Puunene factory in September, 2003, and June, 2004. Tests were conducted on coal and bagasse for all three units and a single test firing fuel oil was conducted in Boiler 3. Measurements of flue gas temperature and composition at the exit of the air preheater were made during each test. Fuel and grate ash were sampled and analyses were performed following the test. Flue gases and temperatures were sampled using probe bundles inserted through access ports in the boiler walls. Each probe bundle was composed of three extraction tubes paired with Type K thermocouples. Boiler 1 was fitted with two probe bundles (a total of six sample extraction locations), whereas Boilers 2 and 3 were fitted with one probe bundle each. Data recorded during the test campaign were later reduced to average values and used to calculate steam generation efficiencies using the energy balance method.

Flue gas temperatures at the exit of the air preheater of the three boilers ranged from 180 to 248ºC. The lowest exit temperature was recorded for Boiler 3 during the fuel oil test. When bagasse and coal were fired, Boiler 1 had the lowest exit temperature and Boilers 2 and 3 were consistently higher by 15 and ~30ºC, respectively. Exit temperatures of all boilers were higher when bagasse was fired, ranging from 220 to 248ºC compared to 189 to 219ºC for coal.

Gas composition measurements made after the air preheater showed carbon monoxide concentrations to be highly dependent on fuel type. Fossil fuels produced relatively low CO concentrations in the range of 10 to 90 ppmv. Bagasse tests exhibited elevated CO concentrations with averages ranging from 1,300 to 3,200 ppmv.

Excess air values calculated for coal tests ranged from 46% for Boiler 3, to 101% and 128% for Boilers 1 and 2, respectively. Excess air values calculated for Boilers 1, 2, and 3 operating on bagasse were 57, 58, and 17%, respectively. The excess air value calculated for Boiler 3 using fuel oil was 99%.

Calculated efficiencies for Boilers 1, 2, and 3 firing coal were 80.8, 76.1, and 82.4%, respectively. Higher excess air values and flue gas exit temperatures were the main factors contributing to the lower efficiency of Boiler 2 compared to the other two units.

Calculated efficiencies for Boilers 1, 2, and 3 firing bagasse were 65.9, 63.2, and 67.2%, respectively, markedly lower than those determined for coal. Boiler 2's lower efficiency resulted from higher flue gas temperature and CO concentrations compared to the other two units. Compared to coal, lower efficiencies observed when firing bagasse were largely due to the different moisture contents of the two fuels, 48% for bagasse and 6 to 10% for coal.

Several opportunities to improve boiler efficiency are evident from the results of the test campaign. Reducing excess air, flue gas CO concentrations, and flue gas exit temperature all can contribute to increased efficiency although the first two items may be more easily addressed in the near term. It is recognized that the ability to respond to these opportunities may largely be determined by the physical limitations of the boiler system's equipment and the constraints imposed by operating the units in conjunction with the Puunene sugar factory.

Potential cost savings from improvements in boiler efficiency were calculated. When all three steam generating units fire coal, a 1% increase in efficiency in each of the three boilers would result in a savings of 9.5 tons of coal per day with an associated cost savings of $620 per day. Similarly, when all three units fire bagasse, a 1% improvement in efficiency would save 21.5 tons fuel (dry basis) per day and result in a cost savings of $750 per day.

Table 5. Projected fuel savings that could result from a 1% improvement in efficiency for each steam generating unit above efficiency values measured on the indicated test date.

Boiler No.	1	1	2	2	3	3	3
Test Date	9/22/03	9/23/03	6/29/04	9/23/03	9/25/03	9/26/03	9/27/03
Fuel	Coal	Bagasse	Coal	Bagasse	Bagasse	Coal	#2 Fuel Oil
Steam Flow rate from Wonderware system, klb/hr	105.9	104.2	104.0	105.3	259.7	266.8	241.8
Steam Pressure from Wonderware system, psig	900.0	899.7	898.7	898.9	421.6	426.8	418.7
Steam Pressure from Wonderware system, MPa	6.2	6.2	6.2	6.2	2.9	2.9	2.9
Steam Temperature from Wonderware system, ºF	694.5	749.9	749.5	749.9	765.9	733.6	725.5
Steam Enthalpy, BTU/lbm	1,326.6	1,364.4	1,364.2	1,364.5	1,396.4	1,378.5	1,374.5
Steam Enthalpy Flow, MMBTU/hr	140.5	142.2	141.9	143.7	362.7	367.7	332.4
Fuel Energy Flow, MM BTU/hr	173.8	215.9	186.4	227.3	539.3	446.2	405.4
Fuel Energy Flow with 1% Increase in Efficiency, MM BTU/hr	171.7	212.7	184.0	223.7	531.4	440.8	400.5
Fuel Energy Savings with 1% increase in Efficiency, MM BTU/hr	2.1	3.2	2.4	3.5	7.9	5.3	4.9
Fuel Heating Value, BTU/lbm (dry basis)	12,476	8,167	12,725	8,167	8,194	12,437	19,640
Fuel Savings with 1% increase in efficiency, ton/day (dry basis)	**2.0**	**4.7**	**2.3**	**5.2**	**11.6**	**5.2**	**3.0**
Fuel Savings with 1% increase in efficiency, Mg per day (dry basis)	1.9	4.3	2.1	4.7	10.5	4.7	2.7
Unit Cost of Fuel ($/dry ton)	65.22	34.78[1]	65.22	34.78[1]	34.78[1]	65.22	454.69[2]
Fuel Cost Savings with 1% increase in efficiency, $/day	**133**	**165**	**149**	**181**	**403**	**337**	**1,357**

[1] Bagasse price based on the price of coal and displacement of coal to generate of an equivalent amount of steam.
[2] Based on a price of $1.59 per gallon

5. References

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Appendix A

STANDARD LABORATORIES,INC.

10/10/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 1/2-COAL-COMP-4

JOB NO.: 200301660004
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	6.55		
ASH	12.28	13.14	
VOLATILE	38.60	41.31	
FIXED C	42.57	45.55	
SULFUR	0.44	0.47	
BTU/#	11640	12456	
		14340	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	6.55		
ASH	12.28	13.14	
SULFUR	0.44	0.47	
NITROGEN	0.99	1.06	
CARBON	65.50	70.09	
HYDROGEN	5.09	5.45	
OXYGEN	9.15	9.79	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	3.62
LBS H20/MM BTU	5.63
LBS ASH/MM BTU	10.55
LBS SULFUR/MM BTU	0.38
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/10/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 1/2-COAL-COMP-5

JOB NO.: 200301660005
LOCATION: ~~CASPER,~~ WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	6.53		
ASH	12.14	12.99	
VOLATILE	38.38	41.06	
FIXED C	42.95	45.95	
SULFUR	0.45	0.48	
BTU/#	11710	12528	
		14398	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	6.53		
ASH	12.14	12.99	
SULFUR	0.45	0.48	
NITROGEN	1.01	1.08	
CARBON	65.74	70.33	
HYDROGEN	5.06	5.41	
OXYGEN	9.08	9.71	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

	AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

	OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	3.80
LBS H2O/MM BTU	5.58
LBS ASH/MM BTU	10.37
LBS SULFUR/MM BTU	0.38
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

	AS RECD	DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/10/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 1/2-COAL-COMP-6

JOB NO.: 200301660006
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	6.60		
ASH	12.36	13.23	
VOLATILE	38.12	40.81	
FIXED C	42.92	45.96	
SULFUR	0.45	0.48	
BTU/#	11622	12443	
		14340	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	6.60		
ASH	12.36	13.23	
SULFUR	0.45	0.48	
NITROGEN	1.03	1.10	
CARBON	65.42	70.04	
HYDROGEN	5.07	5.43	
OXYGEN	9.08	9.72	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	4.15
LBS H2O/MM BTU	5.68
LBS ASH/MM BTU	10.63
LBS SULFUR/MM BTU	0.39
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na_2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/09/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 1/2-BAG 7

JOB NO.: 200301651001
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	48.50		
ASH	0.83	1.62	
VOLATILE	41.82	81.20	
FIXED C	8.85	17.18	
SULFUR	0.06	0.12	
BTU/#	4216	8186	
		8321	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	48.50		
ASH	0.83	1.62	
SULFUR	0.06	0.12	
NITROGEN	0.10	0.19	
CARBON	25.49	49.49	
HYDROGEN	2.90	5.64	
OXYGEN	22.11	42.94	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING REDUCING

ADDITIONAL DATA

AIR DRY LOSS	45.88
LBS H20/MM BTU	115.04
LBS ASH/MM BTU	1.98
LBS SULFUR/MM BTU	0.15
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/09/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 1/2-BAG 8

JOB NO.: 200301651002
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	48.55		
ASH	0.89	1.73	
VOLATILE	41.50	80.66	
FIXED C	9.06	17.61	
SULFUR	0.07	0.13	
BTU/#	4165	8096	
		8239	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	48.55		
ASH	0.89	1.73	
SULFUR	0.07	0.13	
NITROGEN	0.08	0.16	
CARBON	25.61	49.77	
HYDROGEN	2.95	5.74	
OXYGEN	21.85	42.47	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	45.79	
LBS H20/MM BTU	116.57	
LBS ASH/MM BTU	2.14	
LBS SULFUR/MM BTU	0.16	
BASE/ACID RATIO		
T250		DEG F
% ALKALI AS Na2O		
SPECIFIC GRAVITY		
FREE SWELLING INDEX		

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/09/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 1/2-BAG 9

JOB NO.: 200301651003
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	47.39		
ASH	1.14	2.16	
VOLATILE	42.39	80.58	
FIXED C	9.08	17.26	
SULFUR	0.04	0.08	
BTU/#	4325	8220	
		8401	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	47.39		
ASH	1.14	2.16	
SULFUR	0.04	0.08	
NITROGEN	0.07	0.14	
CARBON	25.97	49.37	
HYDROGEN	2.99	5.68	
OXYGEN	22.40	42.57	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	44.61
LBS H20/MM BTU	109.57
LBS ASH/MM BTU	2.63
LBS SULFUR/MM BTU	0.10
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/09/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 3 - BAG 10

JOB NO.: 200301651004
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	46.04		
ASH	1.08	2.00	
VOLATILE	43.47	80.56	
FIXED C	9.41	17.44	
SULFUR	0.04	0.08	
BTU/#	4377	8112	
		8278	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	46.04		
ASH	1.08	2.00	
SULFUR	0.04	0.08	
NITROGEN	0.08	0.15	
CARBON	26.62	49.33	
HYDROGEN	3.08	5.71	
OXYGEN	23.06	42.73	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	43.12
LBS H20/MM BTU	105.19
LBS ASH/MM BTU	2.47
LBS SULFUR/MM BTU	0.10
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO 20

STANDARD LABORATORIES, INC.

10/09/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 3 - BAG 11

JOB NO.: 200301651005
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	47.95		
ASH	0.78	1.49	
VOLATILE	42.25	81.18	
FIXED C	9.02	17.33	
SULFUR	0.05	0.09	
BTU/#	4293	8247	
		8372	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	47.95		
ASH	0.78	1.49	
SULFUR	0.05	0.09	
NITROGEN	0.05	0.09	
CARBON	25.91	49.77	
HYDROGEN	3.00	5.76	
OXYGEN	22.28	42.80	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	44.57
LBS H20/MM BTU	111.69
LBS ASH/MM BTU	1.81
LBS SULFUR/MM BTU	0.11
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO 20

STANDARD LABORATORIES, INC.

10/09/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 3 - BAG 12

JOB NO.: 200301651006
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	49.45		
ASH	0.93	1.84	
VOLATILE	40.76	80.64	
FIXED C	8.86	17.52	
SULFUR	0.04	0.07	
BTU/#	4157	8224	
		8378	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	49.45		
ASH	0.93	1.84	
SULFUR	0.04	0.07	
NITROGEN	0.08	0.15	
CARBON	25.09	49.63	
HYDROGEN	2.86	5.66	
OXYGEN	21.56	42.65	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	46.90	
LBS H20/MM BTU	118.96	
LBS ASH/MM BTU	2.24	
LBS SULFUR/MM BTU	0.09	
BASE/ACID RATIO		
T250		DEG F
% ALKALI AS Na2O		
SPECIFIC GRAVITY		
FREE SWELLING INDEX		

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/10/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR3-COAL-13

JOB NO.: 200301660007
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	10.55		
ASH	12.14	13.57	
VOLATILE	36.79	41.13	
FIXED C	40.52	45.30	
SULFUR	0.45	0.50	
BTU/#	11094	12402	
		14349	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	10.55		
ASH	12.14	13.57	
SULFUR	0.45	0.50	
NITROGEN	0.97	1.08	
CARBON	62.19	69.52	
HYDROGEN	4.76	5.32	
OXYGEN	8.95	10.01	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	7.75
LBS H20/MM BTU	9.51
LBS ASH/MM BTU	10.94
LBS SULFUR/MM BTU	0.40
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/10/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR3-COAL-14

JOB NO.: 200301660008
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	10.70		
ASH	12.05	13.49	
VOLATILE	36.97	41.40	
FIXED C	40.28	45.11	
SULFUR	0.44	0.49	
BTU/#	11112	12443	
		14383	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	10.70		
ASH	12.05	13.49	
SULFUR	0.44	0.49	
NITROGEN	0.95	1.06	
CARBON	62.40	69.88	
HYDROGEN	4.88	5.46	
OXYGEN	8.59	9.62	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING REDUCING

ADDITIONAL DATA

AIR DRY LOSS	7.80
LBS H2O/MM BTU	9.63
LBS ASH/MM BTU	10.84
LBS SULFUR/MM BTU	0.39
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/10/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR3-COAL-15

JOB NO.: 200301660009
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	10.74		
ASH	12.12	13.58	
VOLATILE	36.79	41.22	
FIXED C	40.35	45.20	
SULFUR	0.44	0.49	
BTU/#	11126	12465	
		14424	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	10.74		
ASH	12.12	13.58	
SULFUR	0.44	0.49	
NITROGEN	0.96	1.08	
CARBON	62.25	69.74	
HYDROGEN	4.81	5.39	
OXYGEN	8.68	9.72	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	7.77
LBS H20/MM BTU	9.65
LBS ASH/MM BTU	10.89
LBS SULFUR/MM BTU	0.39
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/23/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 3 -DIESEL 16

JOB NO.: 200301651007
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	0.00		
ASH	0.00	0.00	
SULFUR	0.17	0.17	
BTU/#	19652	19652	
		19652	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	0.00		
ASH	0.00	0.00	
SULFUR	0.17	0.17	
NITROGEN	0.01	0.01	
CARBON	86.84	86.84	
HYDROGEN	11.10	11.10	
OXYGEN	1.88	1.88	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)
AS RECD DRY

FUSION TEMPERATURE OF ASH (F)
OXIDIZING REDUCING

ADDITIONAL DATA

AIR DRY LOSS	0.00
LBS H2O/MM BTU	0.00
LBS ASH/MM BTU	0.00
LBS SULFUR/MM BTU	0.09
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	0.83
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)
AS RECD DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/23/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 3 - DIESEL 17

JOB NO.: 200301651008
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	0.00		
ASH	0.00	0.00	
SULFUR	0.20	0.20	
BTU/#	19609	19609	
		19609	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	0.00		
ASH	0.00	0.00	
SULFUR	0.20	0.20	
NITROGEN	0.01	0.01	
CARBON	86.03	86.03	
HYDROGEN	11.90	11.90	
OXYGEN	1.86	1.86	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD	DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING	REDUCING

ADDITIONAL DATA

AIR DRY LOSS	0.00
LBS H20/MM BTU	0.00
LBS ASH/MM BTU	0.00
LBS SULFUR/MM BTU	0.10
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	0.83
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD	DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

10/23/03

CUSTOMER: HAWAIIAN COMMERCIAL & SUGAR CO

BLR 3 - DIESEL 18

JOB NO.: 200301651009
LOCATION: CASPER, WY
APPROVAL:

PROXIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	0.00		
ASH	0.00	0.00	
SULFUR	0.16	0.16	
BTU/#	19658	19658	
		19658	

ULTIMATE ANALYSIS (%)

	AS RECD	DRY	EQM
MOISTURE	0.00		
ASH	0.00	0.00	
SULFUR	0.16	0.16	
NITROGEN	0.05	0.05	
CARBON	86.50	86.50	
HYDROGEN	12.10	12.10	
OXYGEN	1.19	1.19	

MINERAL ANALYSIS OF ASH (%)

FORMS OF SULFUR (%)

AS RECD DRY

FUSION TEMPERATURE OF ASH (F)

OXIDIZING REDUCING

ADDITIONAL DATA

AIR DRY LOSS	0.00
LBS H2O/MM BTU	0.00
LBS ASH/MM BTU	0.00
LBS SULFUR/MM BTU	0.08
BASE/ACID RATIO	
T250	DEG F
% ALKALI AS Na2O	
SPECIFIC GRAVITY	0.83
FREE SWELLING INDEX	

GRINDABILITY (HGI)

AT % MOISTURE

WATER SOLUBLE ALKALIES (%)

AS RECD DRY

FORM NO. 20

STANDARD LABORATORIES, INC.

HAWAIIAN COMMERCIAL & SUGAR

ATTN: DEREK HEAPHY

23-Dec-03
LOCATION: CASPER, WY
APPROVED:

S/B NO. 20031669

TOTAL ORGANIC CARBON

SAMPLE	CLIENT ID.	TOTAL ORGANIC CARBON (%)
10	BRL 1/2-COAL ASH-A	2.61
11	BRL 1/2-COAL ASH-B	3.02
12	BRL 1/2-COAL ASH-C	2.19
13	BRL 3- COAL ASH-D	2.83
14	BRL 3- COAL ASH-E	3.18
15	BRL 3- COAL ASH-F	4.88

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To Scott | From Scott
Co. | Co.
Dept. 6-2335 | Phone #
Fax # | Fax #

STANDARD LABORATORIES, INC.

Standard Laboratories
Jan Yarborough (307) 234-9957
Steve Miladinovich (307) 234-0013 Fax

HAWAIIAN COMMERCIAL & SUGAR

07-Nov-03
LOCATION: CASPER, WY
APPROVAL:

ATTN: DEREK HEAFEY

JOB NO. 200301660
% COMBUSTIBLES

SAMPLE	CLIENT ID.	MOISTURE (%)	COMBUSTIBLES (%)	LOI (%)
10	BRL 1/2-COAL ASH-A	0.14	4.88	5.02
11	BRL 1/2-COAL ASH-B	0.35	6.08	6.43
12	BRL 1/2-COAL ASH-C	2.51	7.13	9.64
13	BRL 3- COAL ASH-D	8.40	15.97	24.37
14	BRL 3- COAL ASH-E	7.93	15.68	23.61
15	BRL 3- COAL ASH-F	0.14	9.63	9.77

STANDARD LABORATORIES, INC.

12/04/03

Customer: HAWAIIAN COMMERCIAL & SUGAR CO
Job #:200301660

Page 1 of 10
LOCATION: CASPER, WY

CHN - DRY BASIS

SAMPLE NO.	CLIENT ID.	CARBON (%)	HYDROGEN (%)	NITROGEN (%)
010	BLR 1/2-COAL ASH-A	4.65		
011	BLR 1/2-COAL ASH-B	5.72		
012	BLR 1/2-COAL ASH-C	4.64		
013	BLR ~~1/2~~ 3-COAL ASH-D	8.14		
014	BLR ~~1/2~~ 3-COAL ASH-E	8.22		
015	BLR ~~1/2~~ 3-COAL ASH-F	9.25		

June 29, 2004 Boiler #2 Efficiency Tests HC&S

Hazen Research, Inc.
4601 Indiana St.
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Date	July 28 2004
HRI Project	009-444
HRI Series No.	G64/04-1
Date Rec'd.	07/12/04
Cust. P.O.#	

Hawaii Natural Energy Institute
Scott Q. Turn
2540 Dole Street, Holmes Hall 246
Honolulu, Hawaii 96822

Sample Identification
Coal #1 06/29/04 10:20

Reporting Basis >	As Rec'd	Dry	Eqm	Air Dry
Proximate (%)				
Moisture	5.78	0.00		3.62
Ash	13.74	14.58		14.05
Volatile	42.83	45.46		43.81
Fixed C	37.65	39.96		38.52
Total	100.00	100.00	100.00	100.00
Sulfur	0.50	0.53		0.51
Btu/lb (HHV)	11982	12717		12257
MMF Btu/lb	14086	15114		
MAF Btu/lb		14888		
Air Dry Loss (%)	2.24			
Ultimate (%)				
Moisture	5.78	0.00		3.62
Carbon	66.27	70.34		67.79
Hydrogen	4.88	5.18		4.99
Nitrogen	1.03	1.09		1.05
Sulfur	0.50	0.53		0.51
Ash	13.74	14.58		14.05
Oxygen*	7.80	8.28		7.99
Total	100.00	100.00	100.00	100.00
Chlorine**	0.02	0.02		0.02

Forms of Sulfur (as S,%)

	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	0.50	0.53

Lb. Alkali/MM Btu= 0.08
Lb. Ash/MM Btu= 11.46
Lb. SO2/MM Btu= 0.83
HGI= @ % Moisture
As Rec'd. Sp.Gr.=
Free Swelling Index=

Water Soluble Alkalies (%)

Na2O
K2O

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

Hazen Research, Inc.
4601 Indiana St.
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Date	July 28 2004
HRI Project	009-444
HRI Series No.	G64/04-1
Date Rec'd.	07/12/04
Cust. P.O.#	

Hawaii Natural Energy Institute
Scott Q. Turn
2540 Dole Street, Holmes Hall 246
Honolulu, Hawaii 96822

Sample Identification:
Coal #1 06/29/04 10:20

Elemental Analysis of Ash (%)

SI02	68.37
AL203	23.45
TI02	1.89
FE203	1.31
CAO	0.82
MGO	0.44
NA20	0.34
K20	0.34
P205	0.15
S03	0.11
Total	97.22

Ash Fusion Temperatures (Deg F)

	Oxidizing Atmosphere	Reducing Atmosphere
Initial	2700+	2700+
Softening		
Hemispherical		
Fluid		

Ash Viscosity Calculations *

Base Content (%)	3.35
Acid Content (%)	96.65
Dolomite Ratio	38.77
Base/Acid Ratio	0.03
Silica/Alumina Ratio	2.92
T(cv) (Deg F)	ND **
T250 Temperature (Deg F)	>2800
Equiv Silica Content (%)	96.38
Viscosity from equiv Silica @ 2600 F (Poise)	>999.99
Ash Type	HIGH RANK

Slagging Type= LOW
Fouling Type= LOW

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

Note: The sample was calcined prior to elemental analysis.

* 'Fusibility-Viscosity of Lignite-Type Ash'. A.F. Duzy, 1965.
'Coal Ash Deposition Studies and Application to Boiler Design', R.C. Attig and A.F. Duzy, 1969.
'Relationship of Coal-Ash Viscosity to Chemical Composition', W.L. Sage and J.B. McIlroy, 1960.
'Fuel and Ash Characterization and its Effect on the Design of Industrial Boilers', Vecci, et al, 1978.

** OTL=Outside Table Limits. ND=Not Determined.

HAZEN

Hazen Research, Inc.
4601 Indiana St.
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Date	July 28 2004
HRI Project	009-444
HRI Series No.	G64/04-2
Date Rec'd.	07/12/04
Cust. P.O.#	

Hawaii Natural Energy Institute
Scott Q. Turn
2540 Dole Street, Holmes Hall 246
Honolulu, Hawaii 96822

Sample Identification
Coal #2 06/29/04 11:35

Reporting Basis >	As Rec'd	Dry	Eqm	Air Dry
Proximate (%)				
Moisture	7.05	0.00		2.75
Ash	13.08	14.07		13.68
Volatile	40.31	43.36		42.17
Fixed C	39.56	42.57		41.40
Total	100.00	100.00	100.00	100.00
Sulfur	0.51	0.54		0.53
Btu/lb (HHV)	11909	12812		12459
MMF Btu/lb	13882	15128		
MAF Btu/lb		14909		
Air Dry Loss (%)	4.42			
Ultimate (%)				
Moisture	7.05	0.00		2.75
Carbon	66.74	71.80		69.83
Hydrogen	5.12	5.50		5.35
Nitrogen	1.06	1.14		1.11
Sulfur	0.51	0.54		0.53
Ash	13.08	14.07		13.68
Oxygen*	6.44	6.95		6.75
Total	100.00	100.00	100.00	100.00
Chlorine**	0.03	0.03		0.03

Forms of Sulfur (as S,%)	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	0.51	0.54

Lb. Alkali/MM Btu= 0.07
Lb. Ash/MM Btu= 10.98
Lb. SO2/MM Btu= 0.85
HGI= @ % Moisture
As Rec'd. Sp.Gr.=
Free Swelling Index=

Water Soluble Alkalies (%)

Na2O
K2O

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

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Date	July 28 2004
HRI Project	009-444
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Date Rec'd.	07/12/04
Cust. P.O.#	

Hawaii Natural Energy Institute
Scott Q. Turn
2540 Dole Street, Holmes Hall 246
Honolulu, Hawaii 96822

Sample Identification:
Coal #2 06/29/04 11:35

Elemental Analysis of Ash (%)

SIO2	67.55
AL2O3	24.24
TIO2	2.03
FE2O3	1.77
CAO	0.84
MGO	0.47
NA2O	0.40
K2O	0.27
P2O5	0.12
SO3	0.19
Total	97.88

Ash Fusion Temperatures (Deg F)

	Oxidizing Atmosphere	Reducing Atmosphere
Initial	2700+	2700+
Softening		
Hemispherical		
Fluid		

Ash Viscosity Calculations *

Base Content (%)	3.84
Acid Content (%)	96.16
Dolomite Ratio	34.93
Base/Acid Ratio	0.04
Silica/Alumina Ratio	2.79
T(cv) (Deg F)	ND **
T250 Temperature (Deg F)	>2800
Equiv Silica Content (%)	95.64
Viscosity from equiv Silica @ 2600 F (Poise)	>999.99
Ash Type	HIGH RANK

Slagging Type= LOW
Fouling Type= LOW

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

Note: The sample was calcined prior to elemental analysis.

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'Coal Ash Deposition Studies and Application to Boiler Design', R.C. Attig and A.F. Duzy, 1969.
'Relationship of Coal-Ash Viscosity to Chemical Composition', W.L. Sage and J.B. McIlroy, 1960.
'Fuel and Ash Characterization and its Effect on the Design of Industrial Boilers', Vecci, et al, 1978.
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Tel: (303) 279-4501
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Date	July 28 2004
HRI Project	009-444
HRI Series No.	G64/04-2
Date Rec'd.	07/12/04
Cust. P.O.#	

Hawaii Natural Energy Institute
Scott Q. Turn
2540 Dole Street, Holmes Hall 246
Honolulu, Hawaii 96822

Sample Identification
Coal #3 06/24/04 12:06

Reporting Basis >	As Rec'd	Dry	Eqm	Air Dry
Proximate (%)				
Moisture	7.49	0.00		3.04
Ash	14.13	15.27		14.81
Volatile	39.60	42.81		41.51
Fixed C	38.78	41.92		40.64
Total	100.00	100.00	100.00	100.00
Sulfur	0.51	0.55		0.53
Btu/lb (HHV)	11700	12647		12262
MMF Btu/lb	13822	15167		
MAF Btu/lb		14927		
Air Dry Loss (%)	4.59			
Ultimate (%)				
Moisture	7.49	0.00		3.04
Carbon	65.20	70.48		68.34
Hydrogen	4.99	5.39		5.23
Nitrogen	1.02	1.10		1.07
Sulfur	0.51	0.55		0.53
Ash	14.13	15.27		14.81
Oxygen*	6.66	7.21		6.98
Total	100.00	100.00	100.00	100.00
Chlorine**	0.02	0.02		0.02

Forms of Sulfur (as S,%)	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	0.51	0.55

Lb. Alkali/MM Btu= 0.06
Lb. Ash/MM Btu= 12.08
Lb. SO2/MM Btu= 0.86
HGI= @ % Moisture
As Rec'd. Sp.Gr.=
Free Swelling Index=

Water Soluble Alkalies (%)

Na2O
K2O

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

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Date	July 28 2004
HRI Project	009-444
HRI Series No.	G64/04-2
Date Rec'd.	07/12/04
Cust. P.O.#	

Hawaii Natural Energy Institute
Scott Q. Turn
2540 Dole Street, Holmes Hall 246
Honolulu, Hawaii 96822

Sample Identification:
Coal #3 06/24/04 12:06

Elemental Analysis of Ash (%)

SIO2	68.41
AL2O3	24.06
TIO2	1.86
FE2O3	1.24
CAO	0.58
MGO	0.29
NA2O	0.27
K2O	0.24
P2O5	0.09
SO3	0.09
Total	97.13

Ash Fusion Temperatures (Deg F)

	Oxidizing Atmosphere	Reducing Atmosphere
Initial	2700+	2700+
Softening		
Hemispherical		
Fluid		

Ash Viscosity Calculations *

Base Content (%)	2.70
Acid Content (%)	97.30
Dolomite Ratio	33.21
Base/Acid Ratio	0.03
Silica/Alumina Ratio	2.84
T(cv) (Deg F)	ND **
T250 Temperature (Deg F)	>2800
Equiv Silica Content (%)	97.01
Viscosity from equiv Silica @ 2600 F (Poise)	>999.99
Ash Type	HIGH RANK

Slagging Type= LOW
Fouling Type= LOW

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

Note: The sample was calcined prior to elemental analysis.

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'Coal Ash Deposition Studies and Application to Boiler Design', R.C. Attig and A.F. Duzy, 1969.
'Relationship of Coal-Ash Viscosity to Chemical Composition', W.L. Sage and J.B. McIlroy, 1960.
'Fuel and Ash Characterization and its Effect on the Design of Industrial Boilers', Vecci, et al, 1978.

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Golden, CO 80403 USA
Tel: (303) 279-4501
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Date:	July 28, 2004
PROJ. #	009-444
CTRL #	G64/04
REC'D	07/12/04

Hawaii Natural Energy Institute
Scott Q. Turn
2540 Dole Street, Holmes Hall
Honolulu, Hawaii 96822

Sample Number	Sample Identification	Chlorine in Ash, %	Carbon Dioxide in Ash, %
G64/04-1	Coal #1 10:20	0.04	0.08
G64/04-2	Coal #2 11:35	0.02	0.02
G64/04-3	Coal #3 12:06	<0.01	0.04

All samples were dated 06/29/04.
The samples were ashed at 800 degrees Celsius prior to analysis.

By:

Gerard H. Cunningham
Fuel Laboratory Manager

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Date:	July 28, 2004
PROJ. #	009-444
CTRL #	G64/04
REC'D	07/12/04

Hawaii Natural Energy Institute
Scott Q. Turn
2540 Dole Street, Holmes Hall
Honolulu, Hawaii 96822

Sample Number: G64/04-4
Sample Identification: Ash #1 06/29/04 10:20

Air Dry Loss, %	39.44	
LOI @ 800 C, %	44.59	
Carbon Forms	**Air Dry Basis**	**As Received Basis**
Total Carbon,%	7.98	4.83
Carbon Dioxide as C, %	0.03	0.02
Organic Carbon, %*	7.95	4.81

Sample Number: G64/04-5
Sample Identification: Ash #2 06/29/04 11:35

Air Dry Loss, %	42.02	
LOI @ 800 C, %	46.62	
Carbon Forms	**Air Dry Basis**	**As Received Basis**
Total Carbon,%	7.73	4.48
Carbon Dioxide as C, %	0.01	0.01
Organic Carbon, %*	7.72	4.48

Sample Number: G64/04-6
Sample Identification: Ash #3 06/29/04 12:06

Air Dry Loss, %	42.52	
LOI @ 800 C, %	46.55	
Carbon Forms	**Air Dry Basis**	**As Received Basis**
Total Carbon,%	6.58	3.78
Carbon Dioxide as C, %	0.01	0.01
Organic Carbon, %*	6.57	3.78

By:
Gerard H. Cunningham
Fuel Laboratory Manager

* by difference
The LOI values are reported on an "as received" basis.

Hazen Research, Inc.
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Tel: (303) 279-4501
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Date:	August 24, 2004
PROJ. #	009-444
CTRL #	G64/04
REC'D	07/12/04

Hawaii Natural Energy Institute
Scott Q. Turn
2540 Dole Street, Holmes Hall
Honolulu, Hawaii 96822

Sample Number: G64/04-4
Sample Identification: Ash #1 06/29/04 10:20

Air Dry Loss, %	39.44
LOI @ 800 C, %	44.59

Carbon Forms	**Dry Basis**	**Air Dry Basis**	**As Received Basis**
Total Carbon,%	8.01	7.98	4.83
Carbon Dioxide as C, %	0.03	0.03	0.02
Organic Carbon, %*	7.98	7.95	4.81

Sample Number: G64/04-5
Sample Identification: Ash #2 06/29/04 11:35

Air Dry Loss, %	42.02
LOI @ 800 C, %	46.62

Carbon Forms	**Dry Basis**	**Air Dry Basis**	**As Received Basis**
Total Carbon,%	7.76	7.73	4.48
Carbon Dioxide as C, %	0.01	0.01	0.01
Organic Carbon, %*	7.75	7.72	4.48

Sample Number: G64/04-6
Sample Identification: Ash #3 06/29/04 12:06

Air Dry Loss, %	42.52
LOI @ 800 C, %	46.55

Carbon Forms	**Dry Basis**	**Air Dry Basis**	**As Received Basis**
Total Carbon,%	6.60	6.58	3.78
Carbon Dioxide as C, %	0.01	0.01	0.01
Organic Carbon, %*	6.59	6.57	3.78

By:
Gerald H. Cunningham
Fuel Laboratory Manager

* by difference
The LOI values are reported on an "as received" basis.

Appendix B

Table B1. Ten minute averages of test parameters for Boiler 1 firing coal, September 22, 2003.

Time and Location	Average ppm-CO	St Dev CO	Average %CO2	Average %O2	St Dev O2	Average Temp. (C)
10:02 Location 1-1	82.4	5.5	10.7	8.8	0.4	195.3
10:12 Location 1-2	78.7	3.9	9.5	10.2	0.2	189.4
10:22 Location 1-3	96.0	3.6	9.0	10.7	0.2	176.3
10:32 Location 2-1	74.9	9.7	10.0	9.5	0.4	194.5
10:42 Location 2-2	90.7	6.0	8.2	11.6	0.3	188.3
10:52 Location 2-3	93.7	4.0	6.9	13.2	0.2	187.7
11:04 Location 1-1*	80.9	9.3	9.7	9.7	1.2	194.7
11:12 Location 1-2	78.9	5.1	9.6	10.1	0.3	190.2
11:22 Location 1-3	89.8	7.2	9.2	10.5	0.1	176.4
11:32 Location 2-1	65.7	6.9	10.2	9.3	0.2	195.3
11:42 Location 2-2	84.0	4.7	8.6	11.3	0.2	189.6
11:52 Location 2-3	91.1	3.4	6.7	13.4	0.1	187.8
* 4min period						
12:04 Location 1-1	69.7	5.4	10.5	9.0	0.3	196.0
12:14 Location 1-2	78.7	2.6	9.2	10.5	0.2	189.4
12:24 Location 1-3	96.3	6.3	8.9	10.9	0.3	176.7
12:34 Location 2-1	70.1	3.1	9.8	9.7	0.3	194.7
12:51 Location 2-2	82.5	4.5	8.5	11.3	0.2	189.6
13:01 Location 2-3	91.8	4.1	6.8	13.3	0.1	188.5
Average across locations	83.1		9.0	10.7		188.9

Table B2. Ten minute averages of test parameters for Boiler 2 firing coal, June 29, 2004.

Time and Location	Average ppm-CO	St Dev CO	Average %CO2	Average %O2	St Dev O2	Average Temp. (C)
10:12 Location 1-1	55.8	5.2	9.4	10.0	0.3	221.7
11:05 Location 1-2	87.3	3.3	8.7	10.9	0.5	227.7
11:15 Location 1-3	108.7	3.0	5.7	14.5	0.3	207.4
11:25 Location 1-1	65.4	5.9	8.6	11.0	0.4	218.1
11:35 Location 1-2	82.2	5.0	8.7	11.0	0.3	228.8
11:45 Location 1-3	122.8	5.7	6.5	13.6	0.5	208.3
11:55 Location 1-1	67.1	2.7	8.5	11.2	0.2	219.1
12:05 Location 1-2	73.4	3.3	8.5	11.2	0.3	228.7
12:15 Location 1-3	117.8	7.1	6.4	13.7	0.3	207.9
Averages across locations	86.7	4.6	7.9	11.9	0.3	218.6

Table B3. Ten minute averages of test parameters for Boiler 1 firing bagasse, September 23, 2003.

Time and Location	Average ppm-CO	St Dev CO	Average %CO2	Average %O2	St Dev O2	Average Temp. (C)
09:17 Location 1-1	1358.0	384.6	15.2	5.4	4.3	229.1
09:27 Location 1-2	761.5	147.6	13.0	7.6	0.2	219.9
09:37 Location 1-3	1064.1	227.6	12.5	8.1	0.3	202.0
09:47 Location 2-1	906.5	193.1	14.3	6.3	0.2	225.6
09:57 Location 2-2	899.2	91.7	12.2	8.5	0.2	220.4
10:07 Location 2-3	670.2	61.2	9.2	11.6	0.1	215.5
10:17 Location 1-1	761.4	92.8	14.7	6.0	0.2	226.8
10:27 Location 1-2	936.5	185.2	13.5	7.2	0.3	219.5
10:37 Location 1-3	1306.0	219.7	12.9	7.8	0.2	203.8
10:47 Location 2-1	1141.2	267.6	14.5	6.0	0.3	227.4
10:57 Location 2-2	1220.3	287.3	12.4	8.2	0.3	223.1
11:07 Location 2-3	2819.3	287.3	10.5	10.0	0.3	220.8
11:34 Location 1-1	2559.3	988.9	15.7	4.7	0.6	232.6
11:49 Location 1-2	2253.4	744.2	14.4	6.1	0.4	223.8
11:59 Location 1-3	999.0	225.0	12.4	8.1	0.6	205.8
12:09 Location 2-1	1199.4	497.5	14.2	6.2	0.5	227.7
12:19 Location 2-2	1500.8	519.8	12.6	8.0	0.3	224.4
12:29 Location 2-3	1234.3	298.1	9.5	11.2	0.5	219.3
Averages across locations	1310.6		13.0	7.6		220.4

Table B4. Ten minute averages of test parameters for Boiler 2 firing bagasse, September 23, 2003.

Time and Location	Average ppm-CO	St Dev CO	Average %CO2	Average %O2	St Dev O2	Average Temp. (C)
13:19 Location 3-1	4014.1	1066.1	13.9	6.4	0.7	247.4
13:34 Location 3-2	2666.2	1447.4	14.5	5.8	1.2	266.9
13:44 Location 3-3	1972.5	490.3	9.8	10.9	0.3	232.1
13:54 Location 3-1	1893.1	407.7	13.3	7.1	0.4	246.5
14:04 Location 3-2	3806.3	1820.4	14.7	5.3	2.4	265.9
14:14 Location 3-3	2272.7	790.0	9.9	10.8	0.5	231.1
14:24 Location 3-1	1418.0	488.3	13.0	7.5	0.3	245.6
14:34 Location 3-2	3179.2	768.8	15.5	5.0	0.2	267.3
14:44 Location 3-3	3043.1	1507.3	9.6	10.9	0.9	230.4
Averages across locations	2696.1		12.7	7.7		248.1

Table B5. Ten minute averages of test parameters for Boiler 3 firing bagasse, September 25, 2003.

Time and Location	Average ppm-CO	St Dev CO	Average %CO2	Average %O2	St Dev O2	Average Temp. (C)
8:57 Location 3-1	3162.5	1475.3	18.3	2.3	0.7	237.6
9:07 Location 3-2	2662.6	1254.7	17.8	2.9	0.7	251.1
9:17 Location 3-3	2861.3	435.7	13.8	5.4	1.1	211.4
9:27 Location 3-1	4432.1	804.6	18.6	1.8	0.5	240.2
9:37 Location 3-2	3281.5	1868.7	17.9	2.4	1.3	248.6
10:14 Location 3-1	5114.0	0.0	19.4	0.7	0.2	250.9
10:35 Location 3-2*	4374.0	855.1	18.5	2.0	0.5	261.7
10:59 Location 3-1	4984.3	409.7	19.0	1.5	0.3	256.1
*12min period						
12:58 Location 3-2	4519.1	909.2	17.9	2.6	0.4	250.1
13:08 Location 3-1	2440.1	952.6	17.0	3.6	0.5	245.9
13:18 Location 3-3	2413.6	957.4	16.0	4.7	0.7	211.2
13:28 Location 3-1	4788.5	426.7	18.3	2.1	0.3	249.9
13:38 Location 3-2	5114.0	0.0	18.6	1.7	0.2	257.8
13:48 Location 3-3	2043.0	656.1	17.0	3.7	0.3	208.9
13:58 Location 3-1	1986.6	551.6	17.9	2.7	0.2	236.6
14:08 Location 3-2	2383.7	843.7	17.0	3.6	0.5	231.9
14:18 Location 3-3	1237.6	244.3	14.9	5.6	0.3	195.7
14:28 Location 3-1	2287.9	993.7	17.4	3.2	0.4	230.1
14:38 Location 3-2	2040.4	800.4	17.2	3.5	0.4	231.4
14:48 Location 3-3	984.1	327.4	15.6	5.0	0.4	194.4
Averages across locations	3155.5		17.4	3.0		235.1

Table B6. Ten minute averages of test parameters for Boiler 3 firing coal, September 26, 2003.

Time and Location	Average ppm-CO	St Dev CO	Average %CO2	Average %O2	St Dev O2	Average Temp. (C)
10:18 Location 3-1	8.6	1.0	11.7	7.6	0.2	212.6
10:28 Location 3-2	14.0	1.9	12.5	6.7	0.2	214.1
10:38 Location 3-3	12.7	1.8	12.4	6.7	0.4	179.9
10:48 Location 3-1	7.6	1.1	12.1	7.0	0.4	211.8
10:58 Location 3-2	15.7	1.1	13.3	5.7	0.2	213.8
11:08 Location 3-3	14.1	4.6	12.6	6.5	0.3	178.9
11:18 Location 3-1	8.4	0.9	11.7	7.6	0.2	213.0
13:03 Location 3-1	7.1	2.3	12.3	6.9	0.3	218.3
13:13 Location 3-2	11.9	0.8	13.0	6.1	0.2	214.6
13:23 Location 3-3	10.3	1.4	12.5	6.7	0.3	181.3
13:33 Location 3-1	6.6	0.8	11.8	7.4	0.2	214.0
13:43 Location 3-2	12.2	0.7	12.9	6.2	0.2	212.9
13:53 Location 3-3	8.5	1.0	12.5	6.6	0.3	179.0
14:03 Location 3-1	6.8	0.6	11.8	7.4	0.1	214.3
Averages across locations	10.3		12.3	6.8		204.2

Table B7. Ten minute averages of test parameters for Boiler 3 firing fuel oil, September 27, 2003.

Time and Location	Average ppm-CO	St Dev CO	Average %CO2	Average %O2	St Dev O2	Average Temp. (C)
10:04 Probe 3-2	22.6	9.8	9.8	7.5	0.4	183.7
10:14 Probe 3-3	-11.1	1.7	9.6	8.0	0.3	159.8
10:24 Probe 3-1	-5.2	2.0	8.8	8.8	1.1	179.5
10:34 Probe 3-2	-4.1	6.1	8.6	9.4	0.5	182.9
10:44 Probe 3-3	-11.3	2.5	8.9	8.7	0.4	160.4
10:54 Probe 3-1	-13.2	0.7	9.4	8.1	0.2	180.2
11:52 Probe 3-1*	11.9	4.6	7.6	10.7	0.2	186.1
12:00 Probe 3-2	35.6	9.8	6.9	11.5	0.2	193.4
12:10 Probe 3-3	11.6	4.7	7.0	11.5	0.4	168.0
12:20 Probe 3-1	17.6	3.8	7.3	11.0	0.1	185.3
12:30 Probe 3-2	52.6	12.2	6.6	12.1	0.1	192.6
12:40 Probe 3-3	26.2	5.8	7.3	11.0	0.1	167.5
12:50 Probe 3-1	50.5	15.3	6.7	11.8	0.2	184.8
13:00 Probe 3-2	20.7	8.1	7.6	10.6	0.2	191.6
13:10 Probe 3-3	35.3	10.5	6.8	11.9	0.5	167.6
* 4 min period						
13:26 Probe 3-1	28.0	10.0	7.6	10.7	0.3	186.1
13:36 Probe 3-2	63.8	11.3	6.9	11.7	0.2	193.1
13:46 Probe 3-3	26.8	11.5	6.8	11.8	0.3	167.3
13:56 Probe 3-1	17.9	8.6	7.8	10.4	0.2	186.5
14:06 Probe 3-2	54.5	8.0	6.9	11.7	0.2	193.6
14:16 Probe 3-3	18.7	22.7	6.7	11.9	2.4	168.6
14:26 Probe 3-1	38.9	33.4	5.5	13.6	4.1	185.6
14:36 Probe 3-2	87.8	13.5	6.9	11.6	0.2	193.9
14:46 Probe 3-3	38.4	10.4	6.8	11.7	0.3	168.8
Averages across locations	25.6		7.5	10.7		180.3

Appendix C

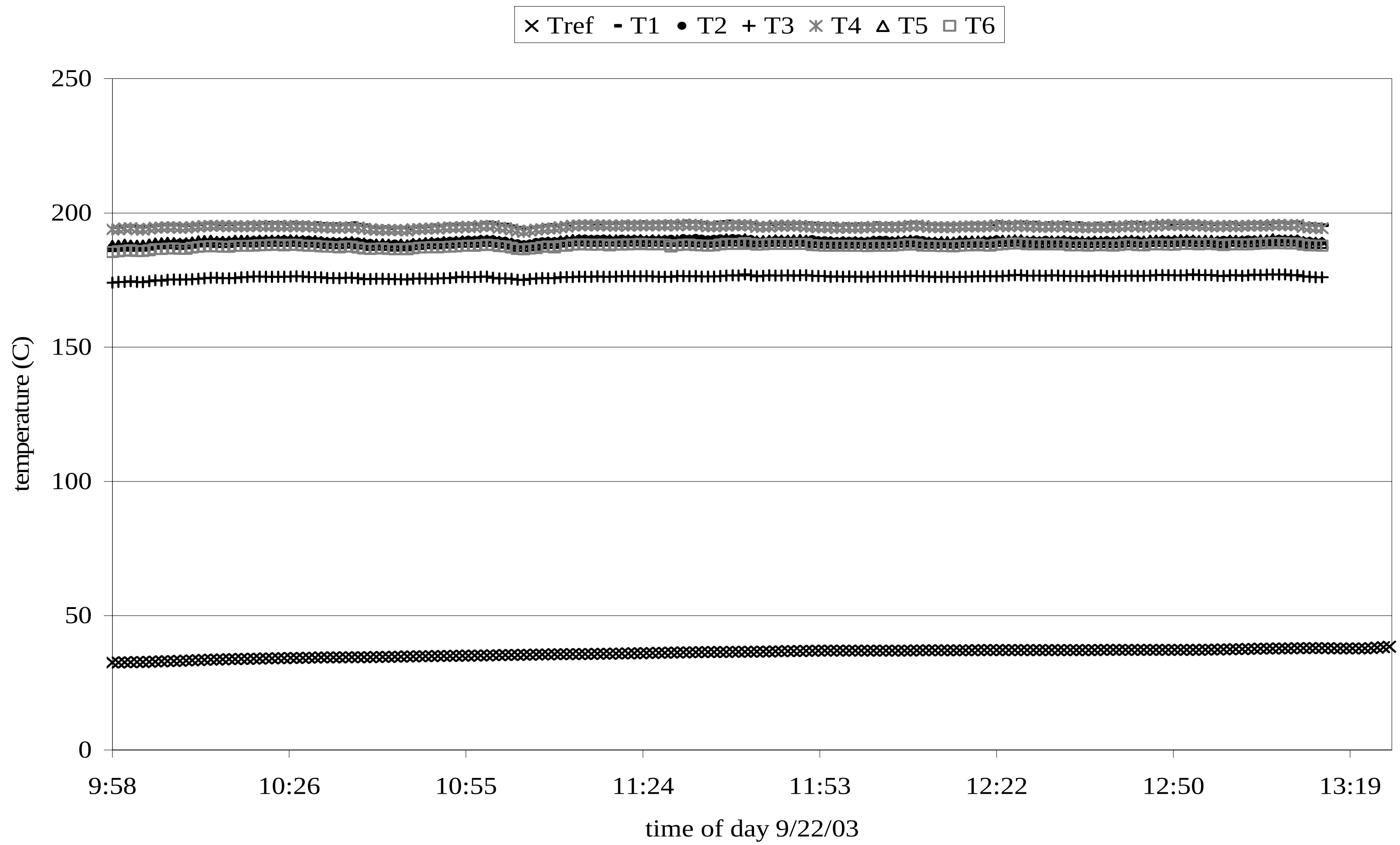


Figure C1. Temperatures recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003. Temperatures T1 though T6 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

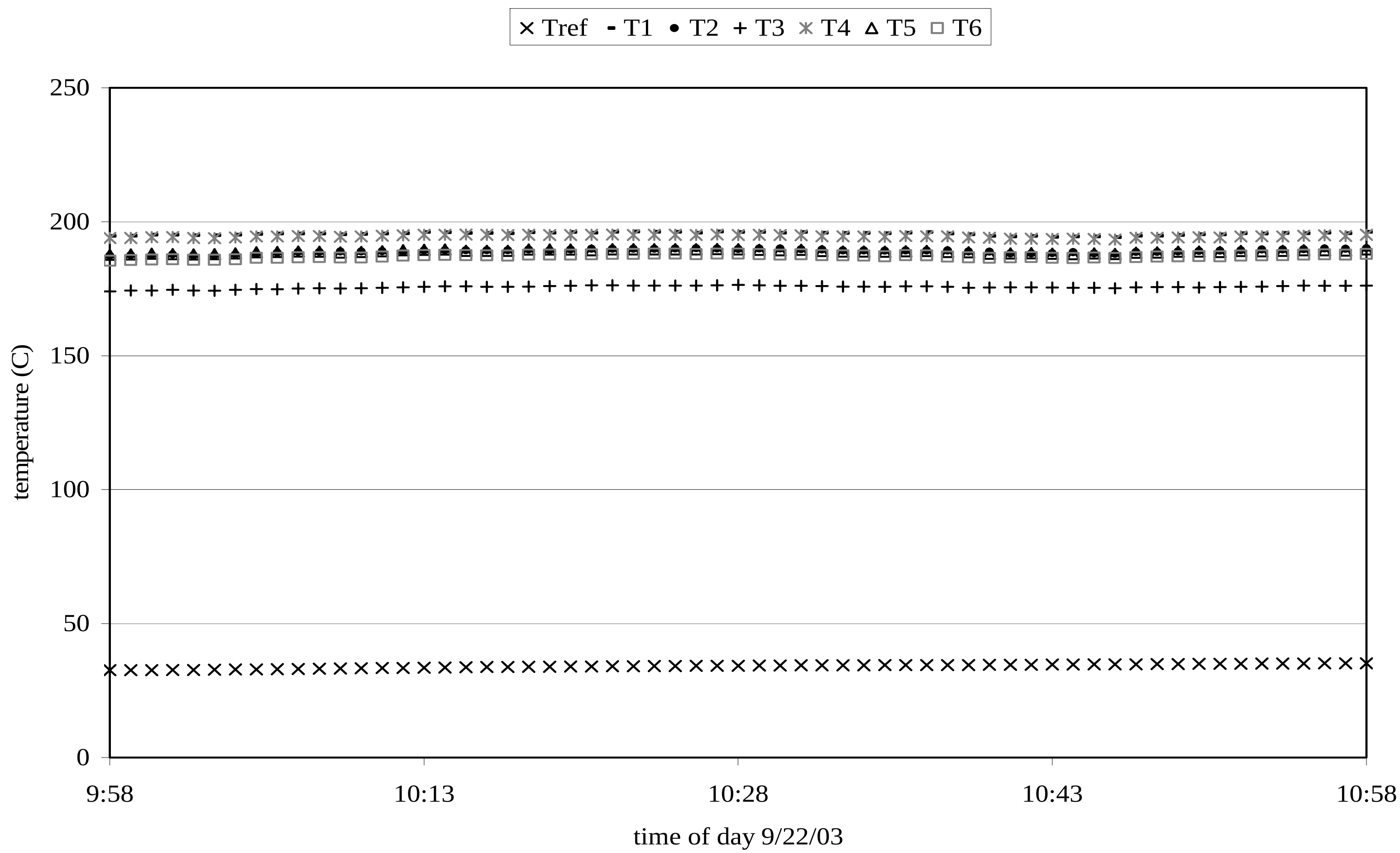


Figure C2. Temperatures recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, first sample period. Temperatures T1 though T6 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

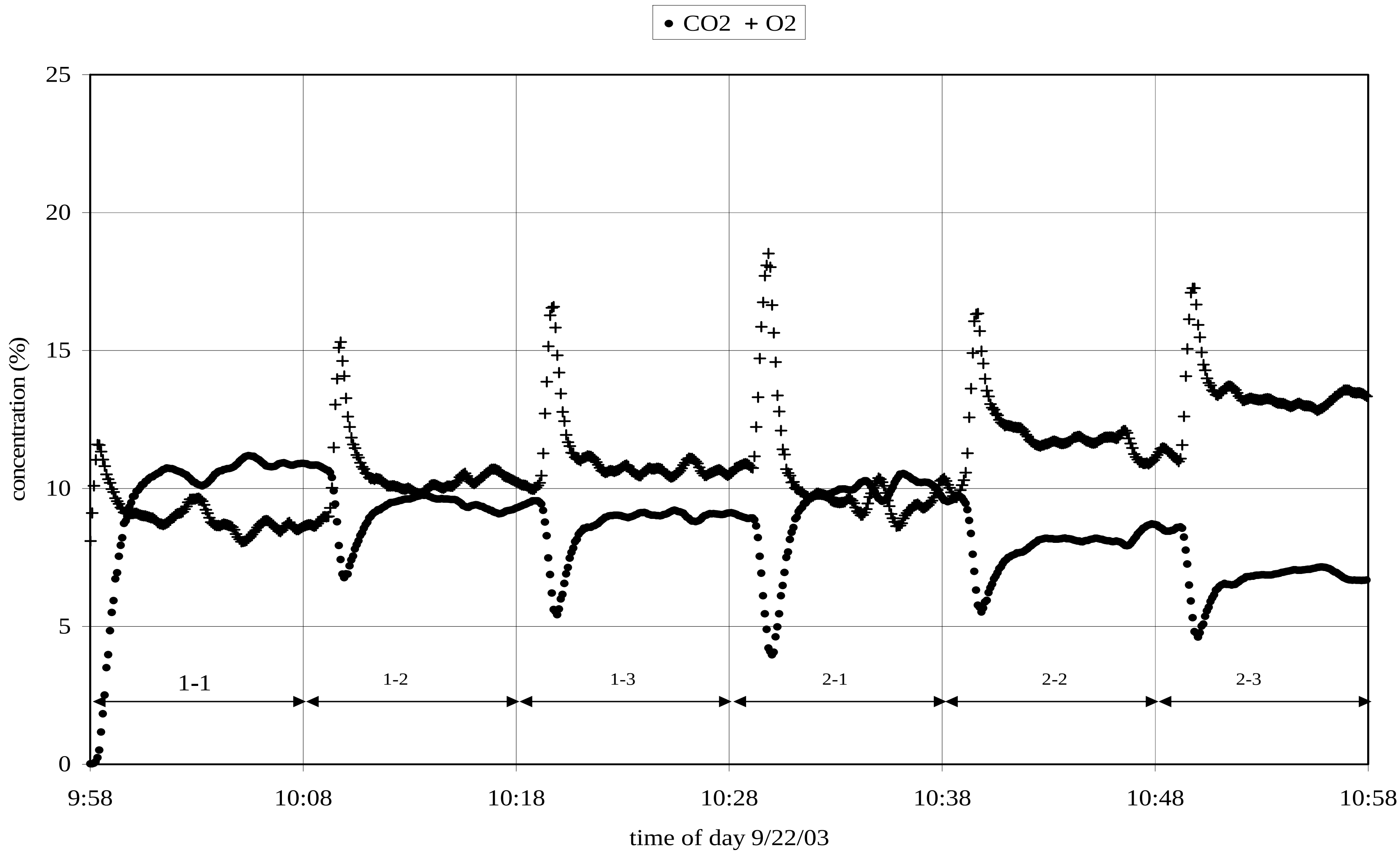


Figure C3. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, first sample period.

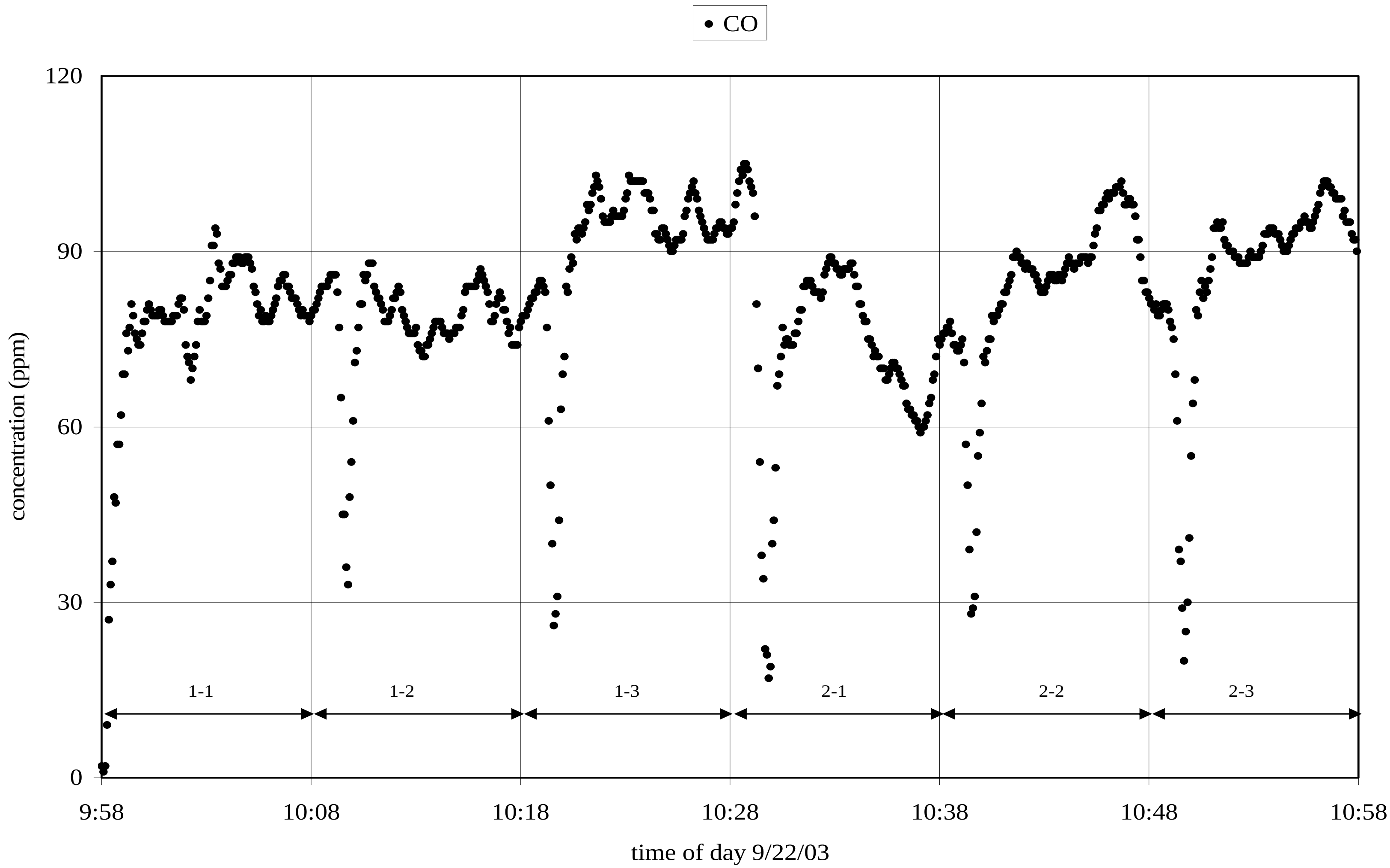


Figure C4. CO concentrations recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, first sample period.

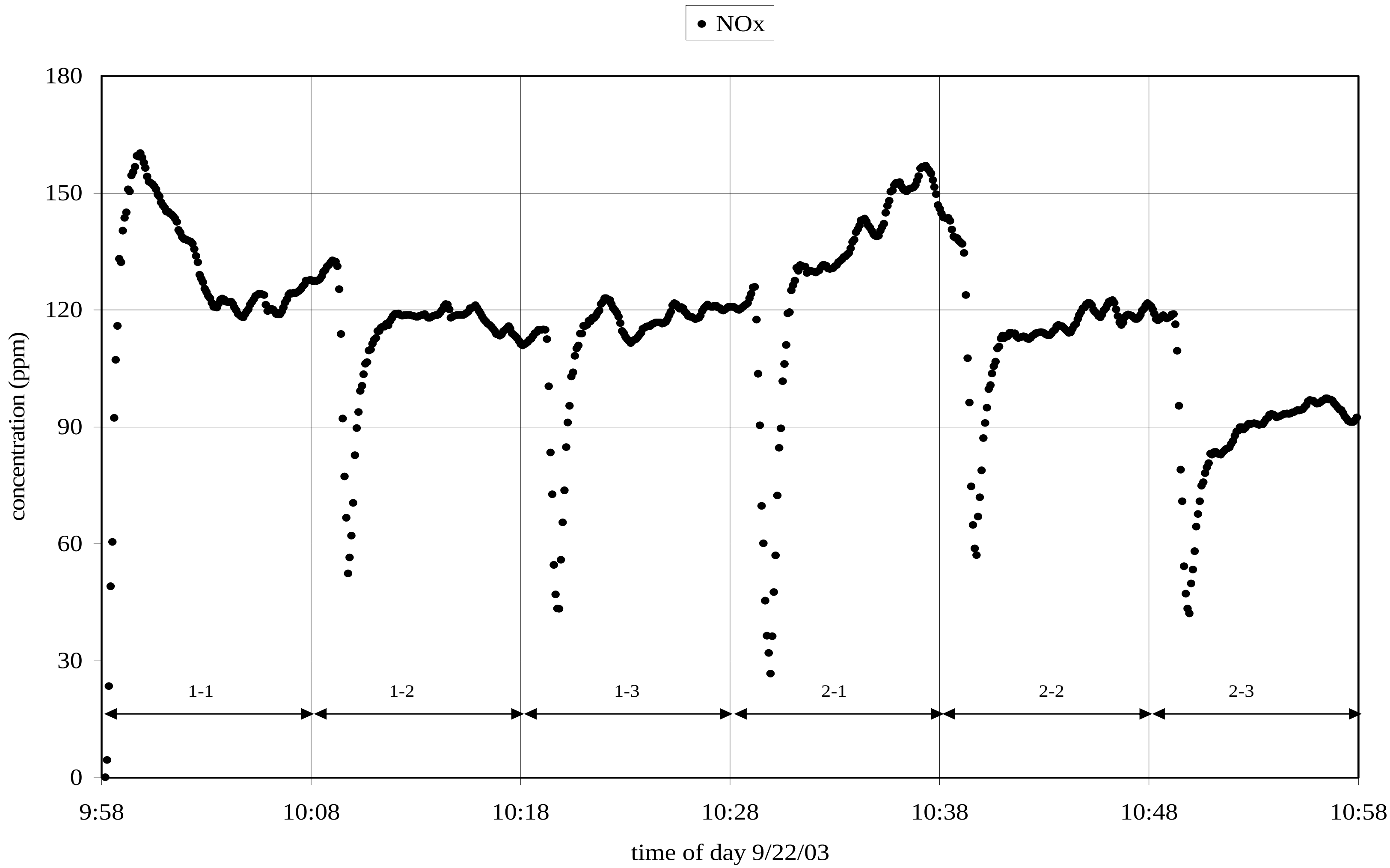


Figure C5. NOx concentrations recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, first sample period.

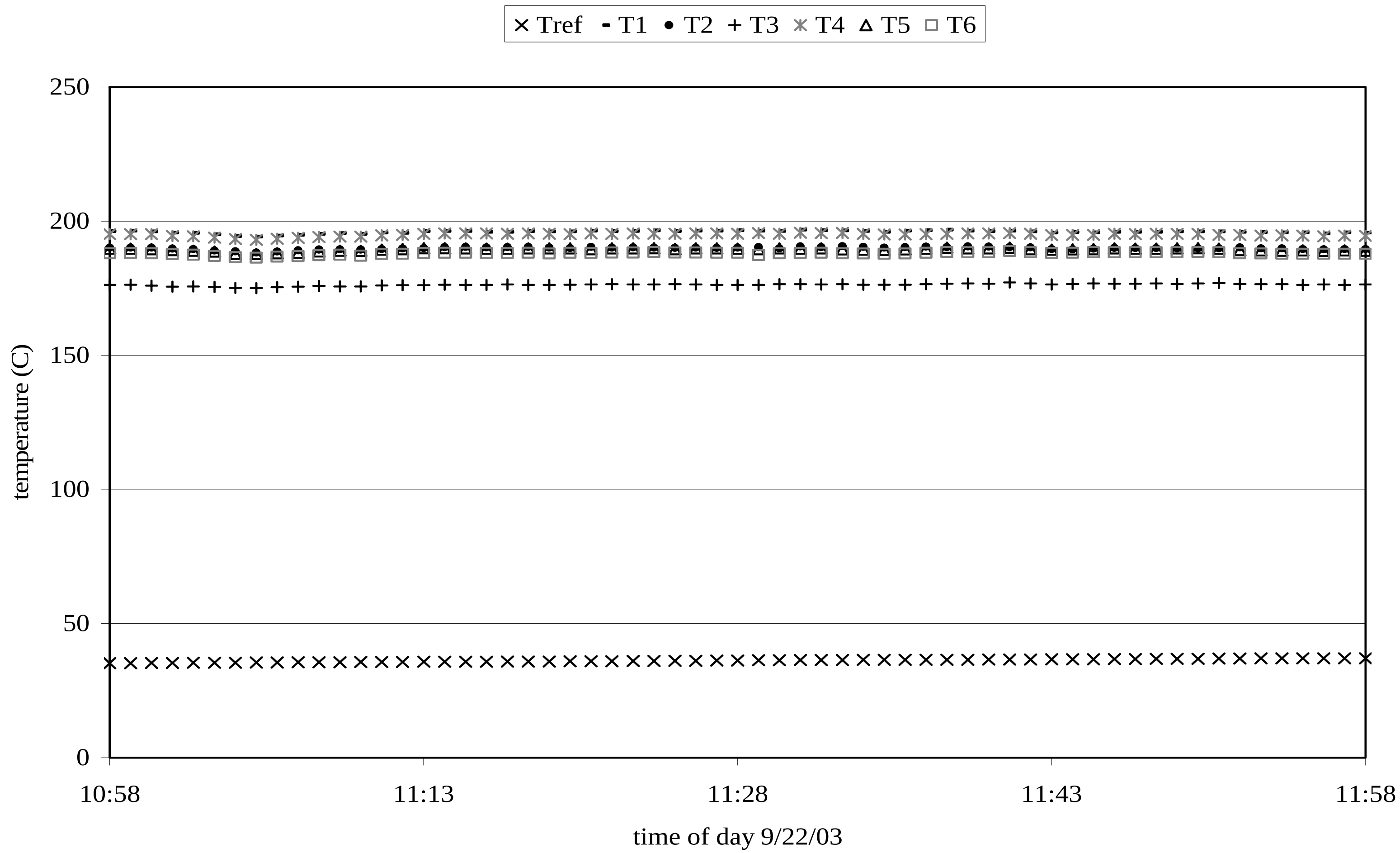


Figure C6. Temperatures recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, second sample period. Temperatures T1 though T6 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

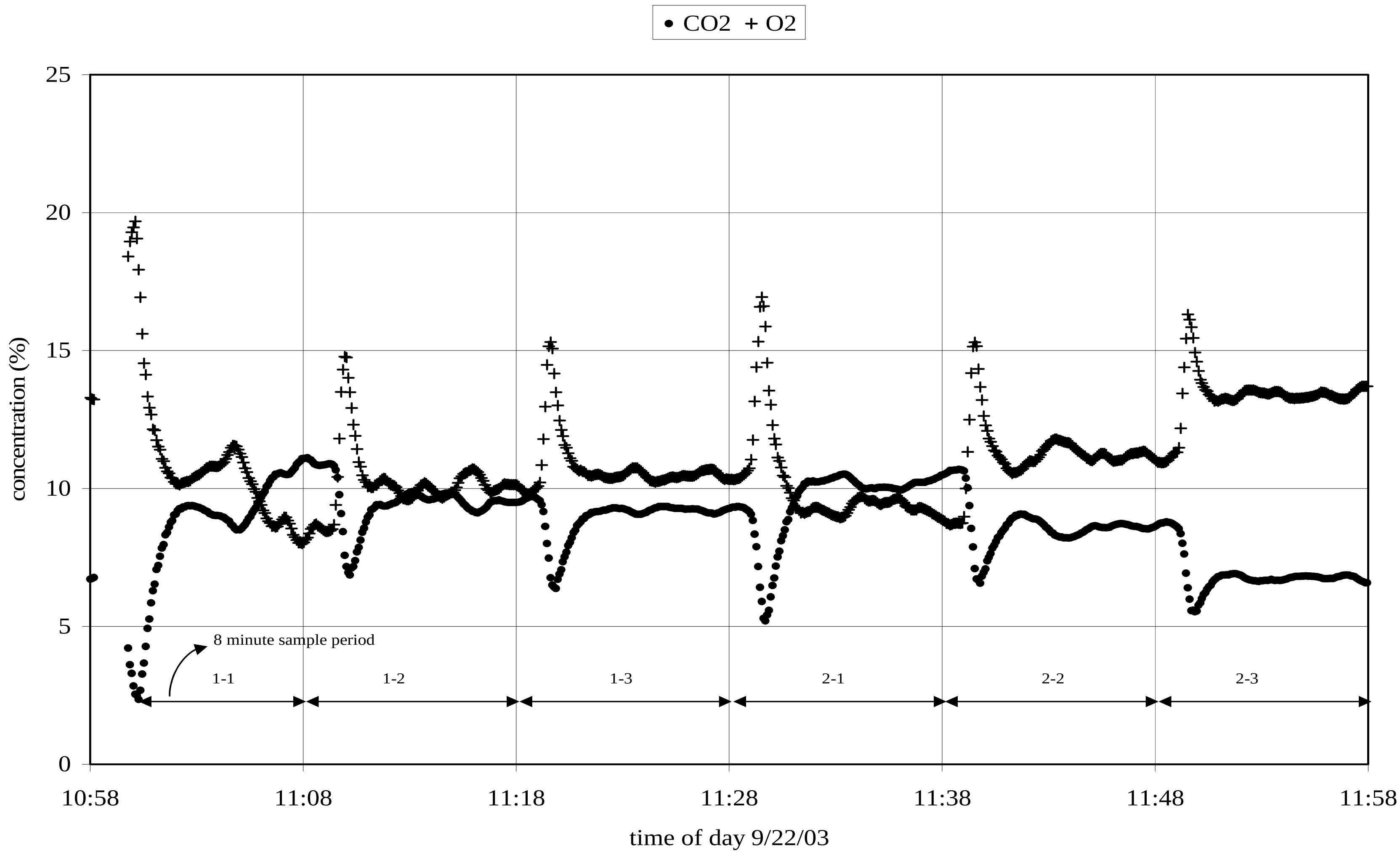


Figure C7. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, second sample period.

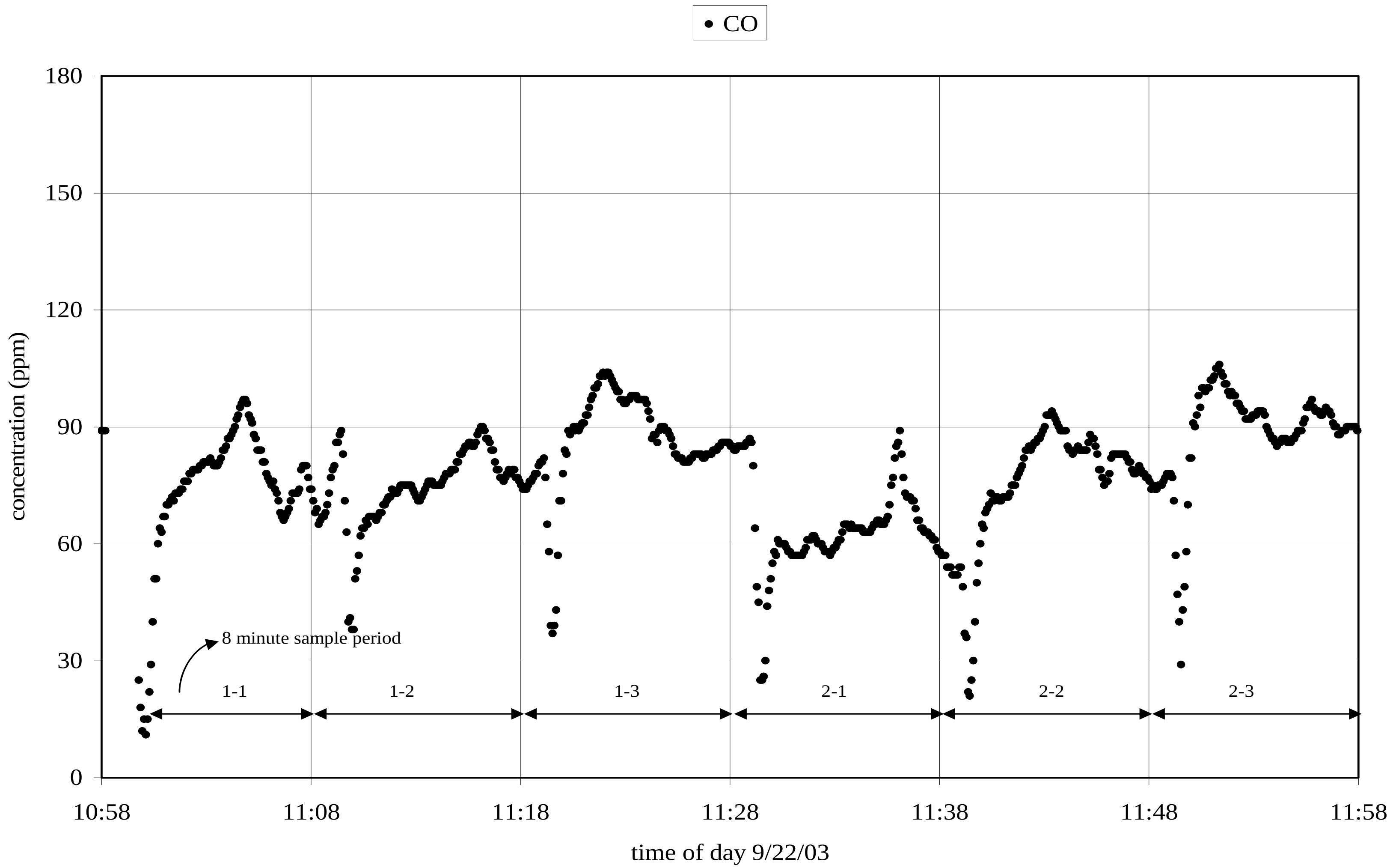


Figure C8. CO concentrations recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, second sample period.

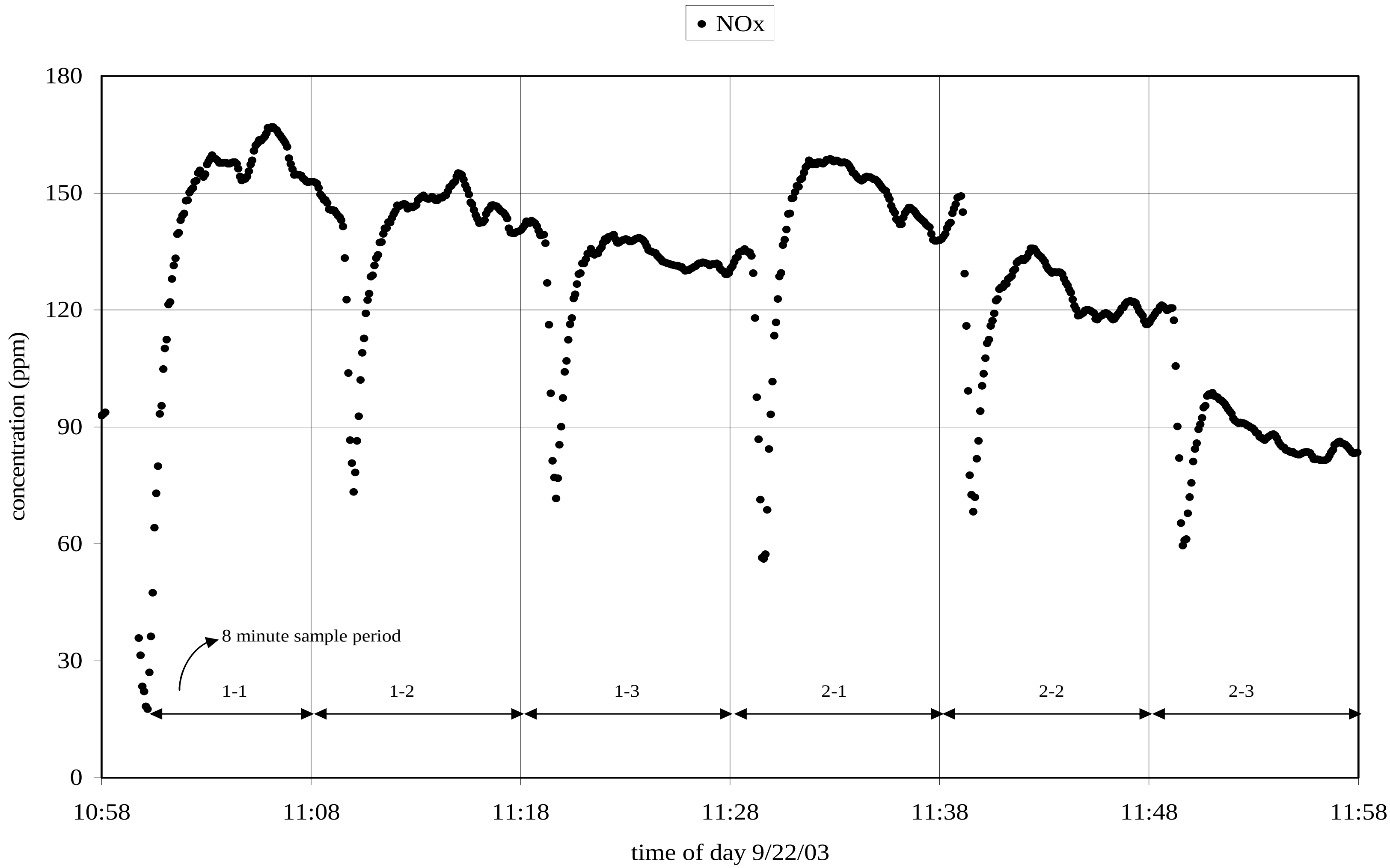


Figure C9. NOx concentrations recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, second sample period.

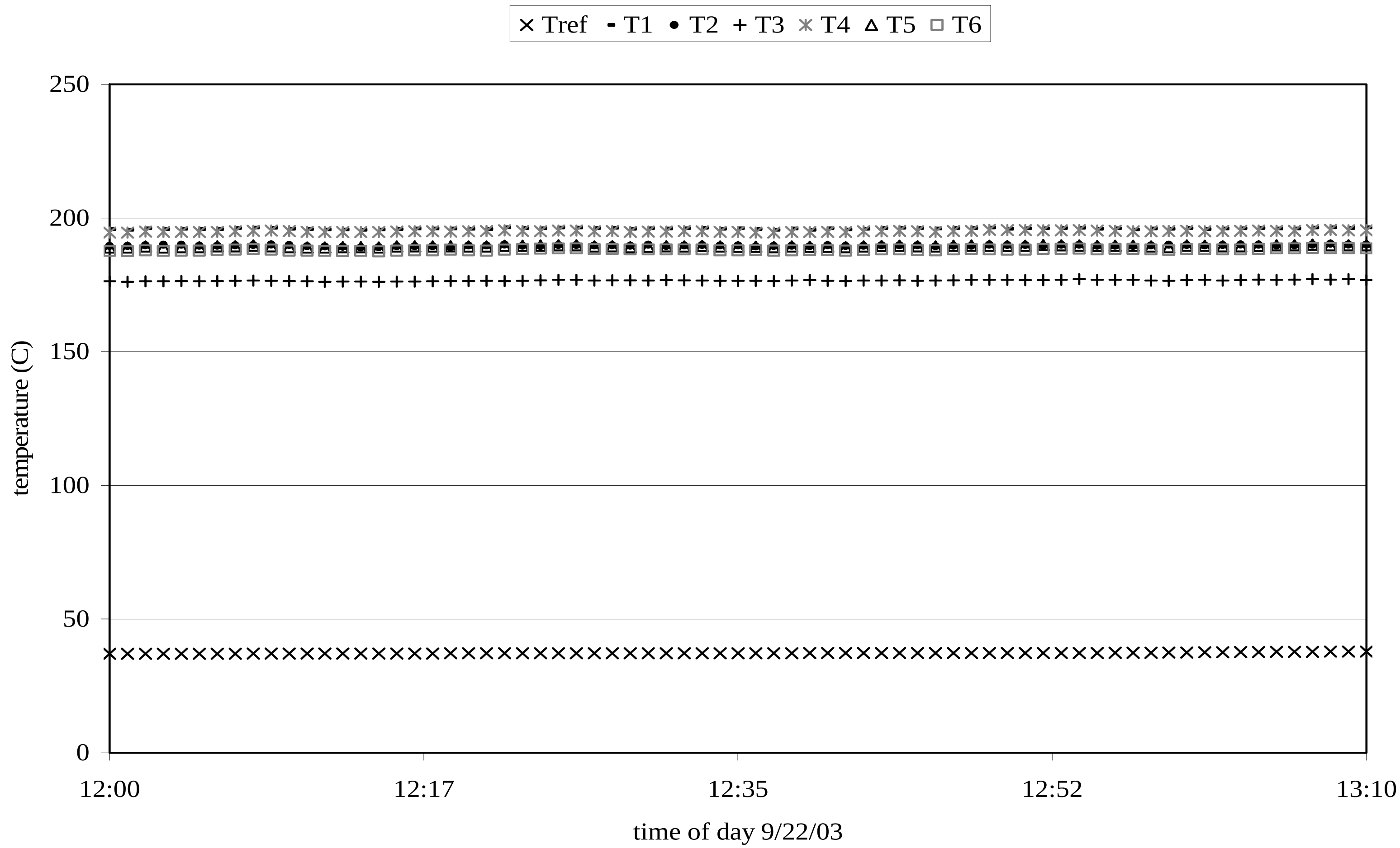


Figure C10. Temperatures recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, third sample period. Temperatures T1 though T6 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

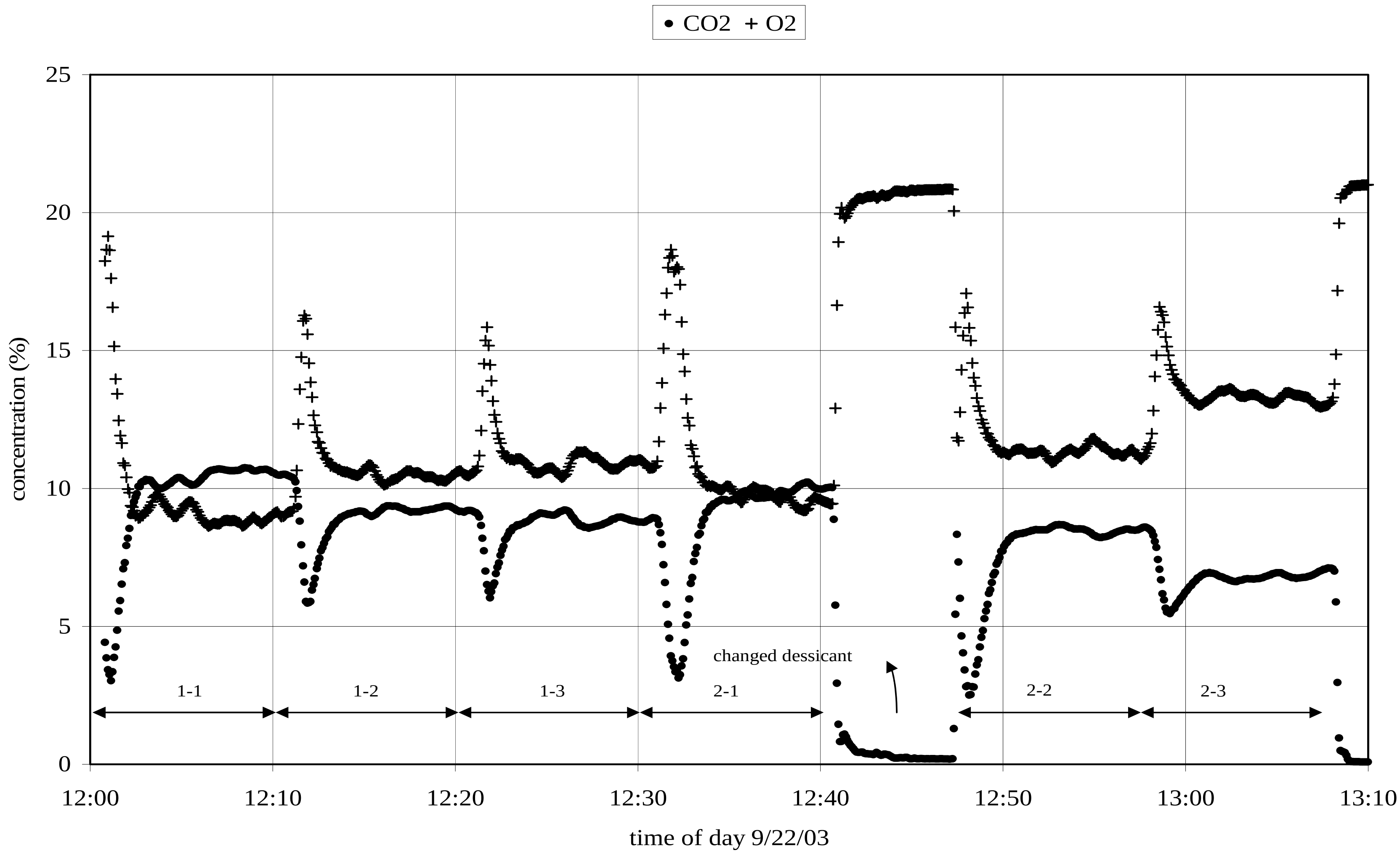


Figure C11. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, third sample period.

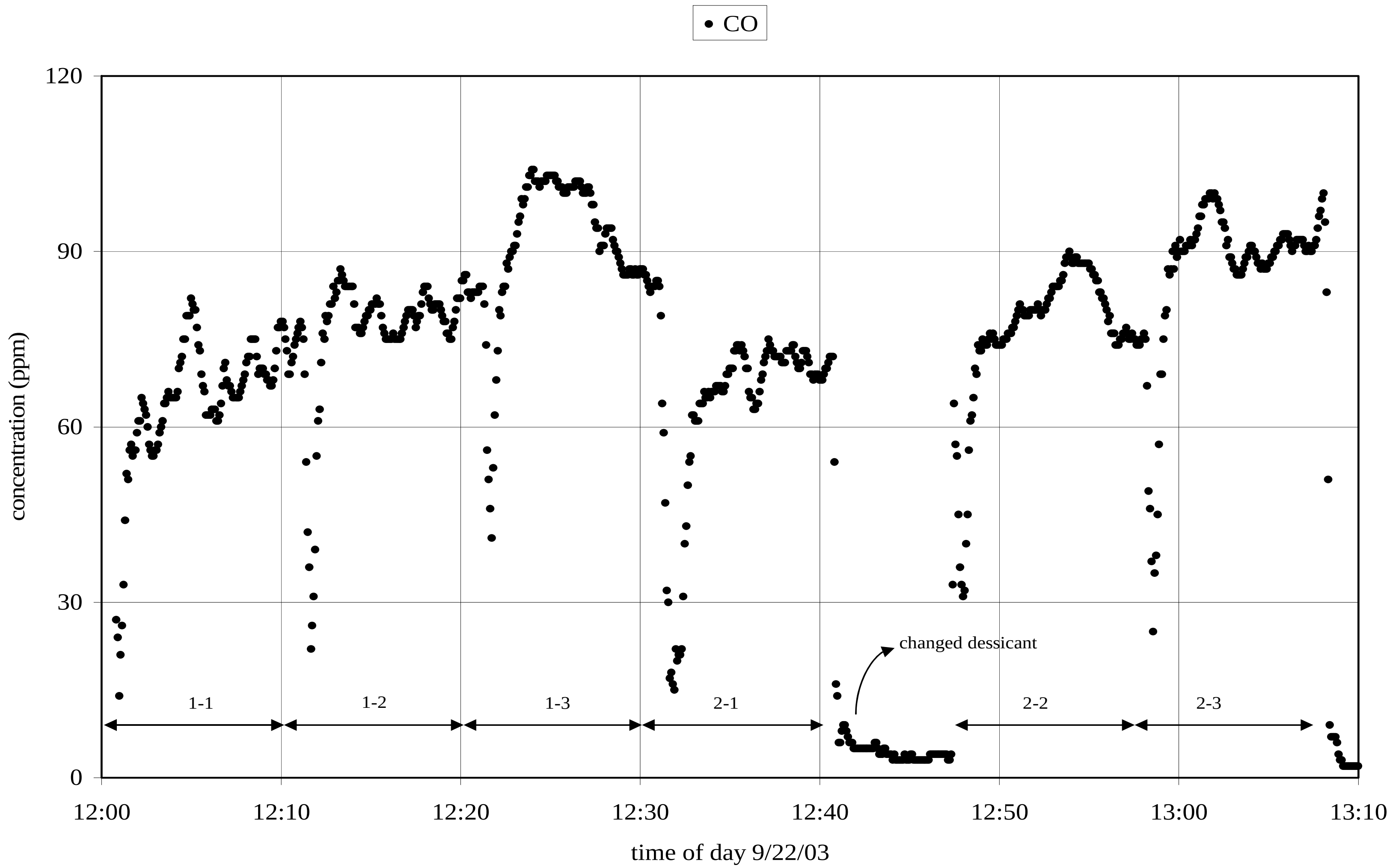


Figure C12. CO concentrations recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, third sample period.

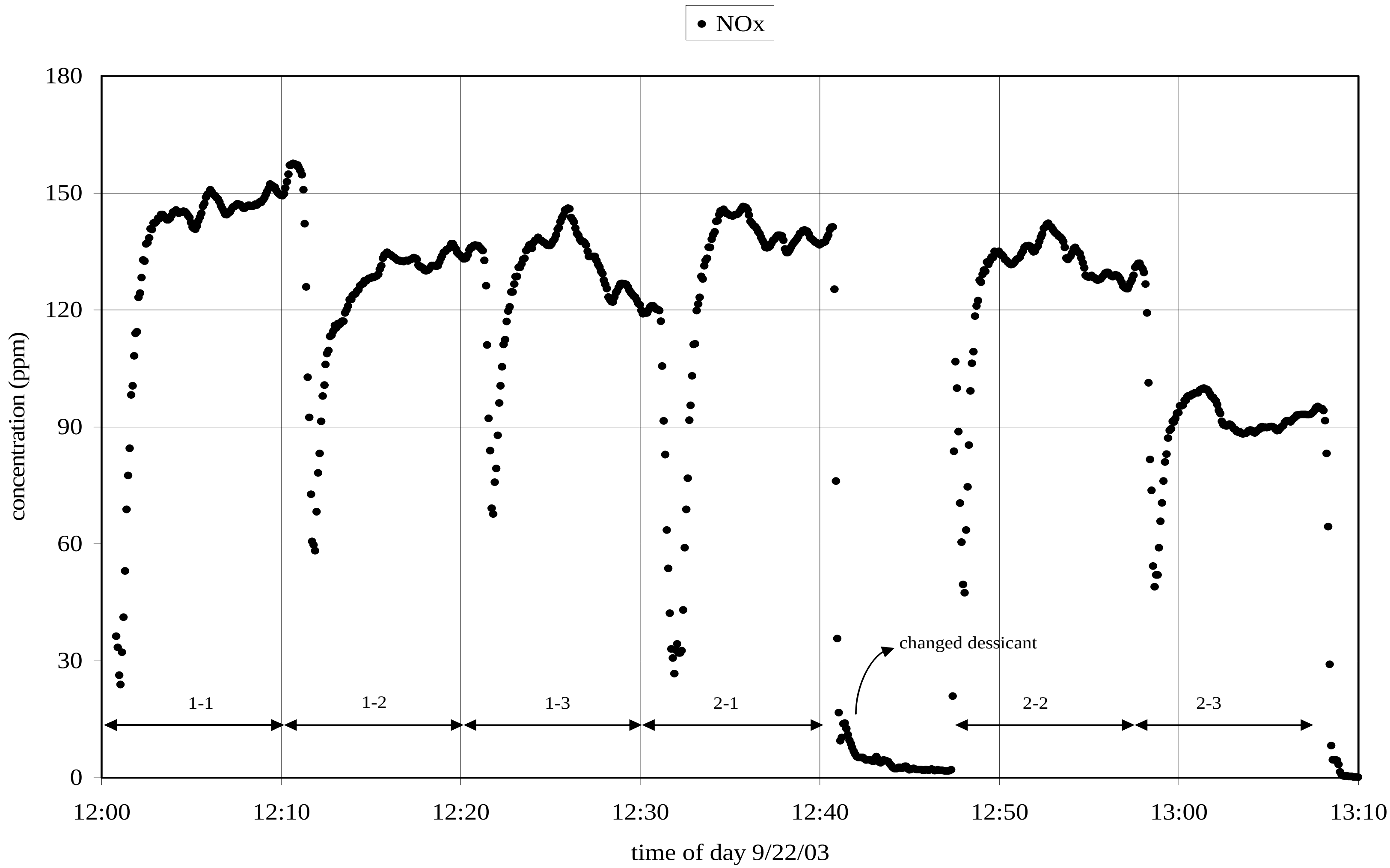


Figure C13. NOx concentrations recorded downstream of the air preheater in Boiler 1 firing coal on September 22, 2003, third sample period.

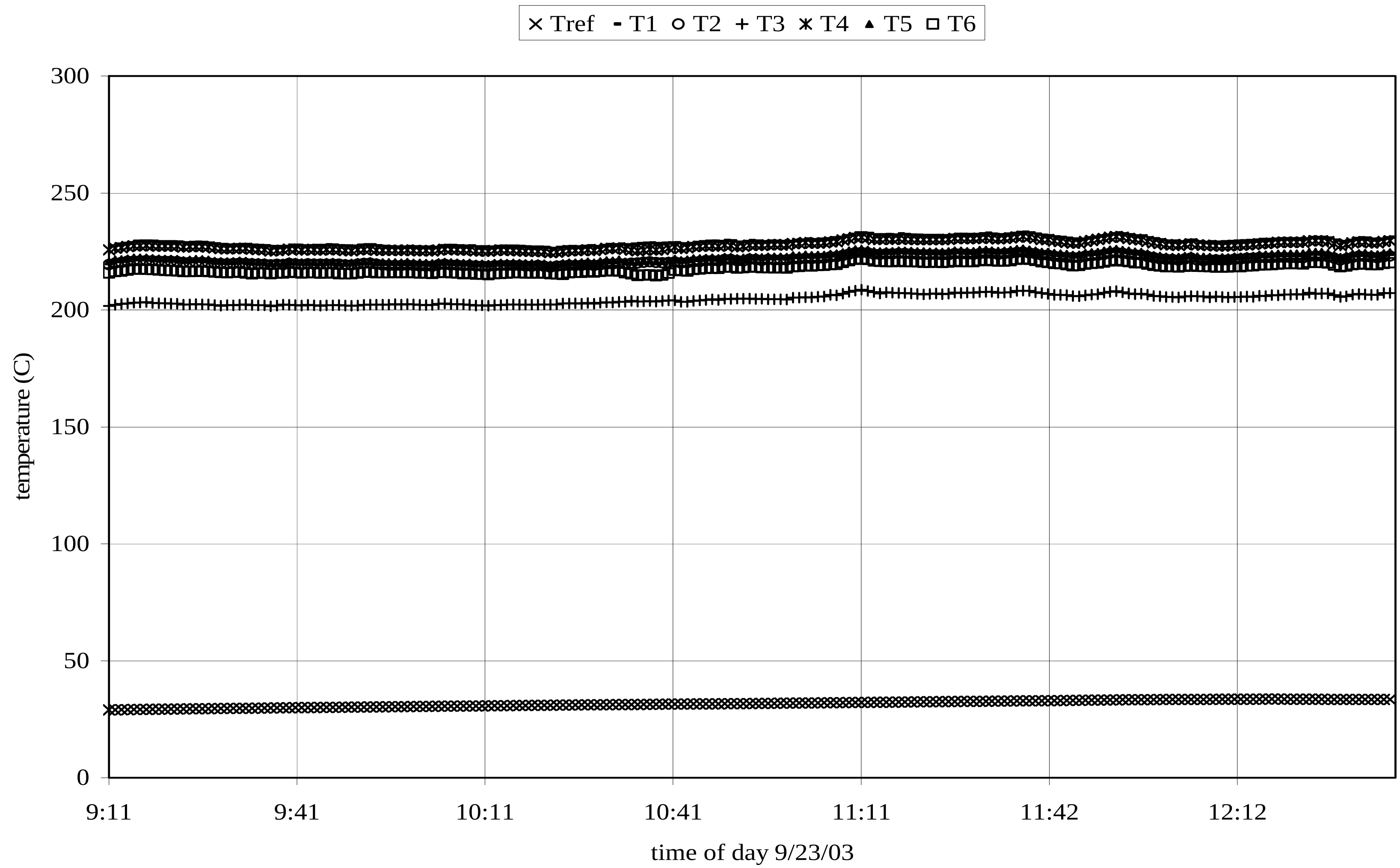
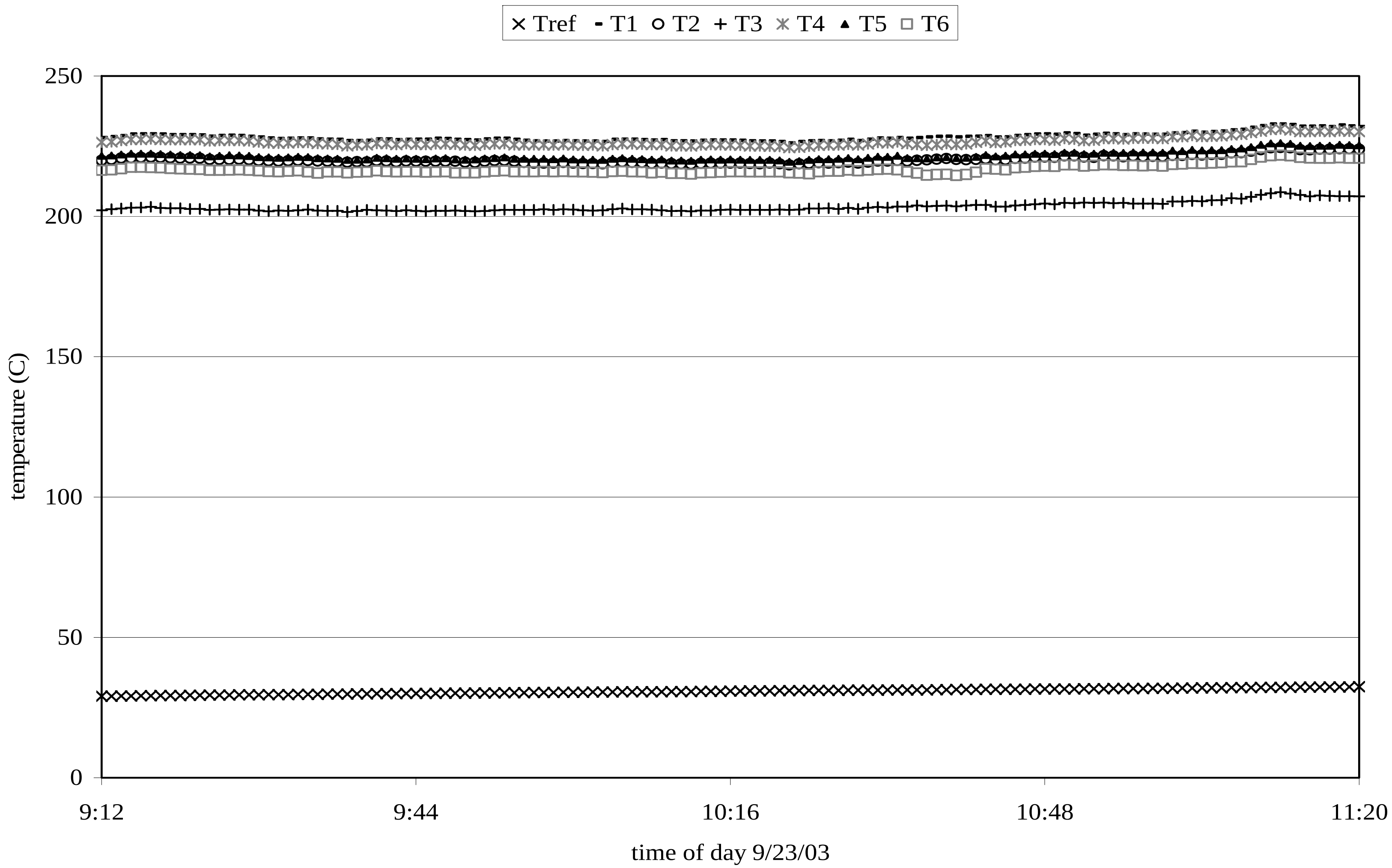


Figure C14. Temperatures recorded downstream of the air preheater in Boiler 1 firing bagasse on September 23, 2003. Temperatures T1 though T6 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.



C15. Temperatures recorded downstream of the air preheater in Boiler 1 firing bagasse on September 23, 2003, first sample period. Temperatures T1 though T6 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

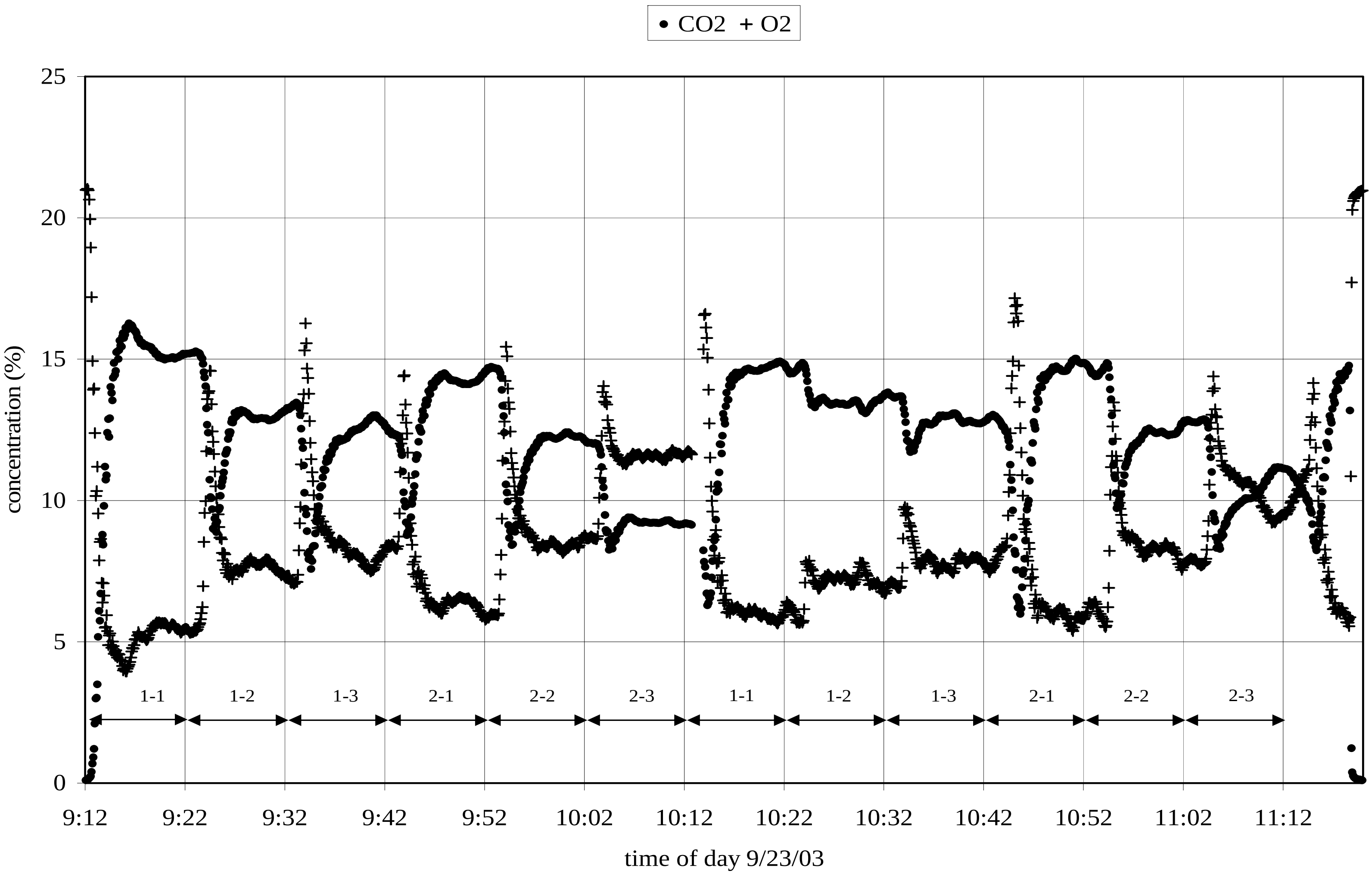


Figure C16. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 1 firing bagasse on September 23, 2003, first and second sample period.

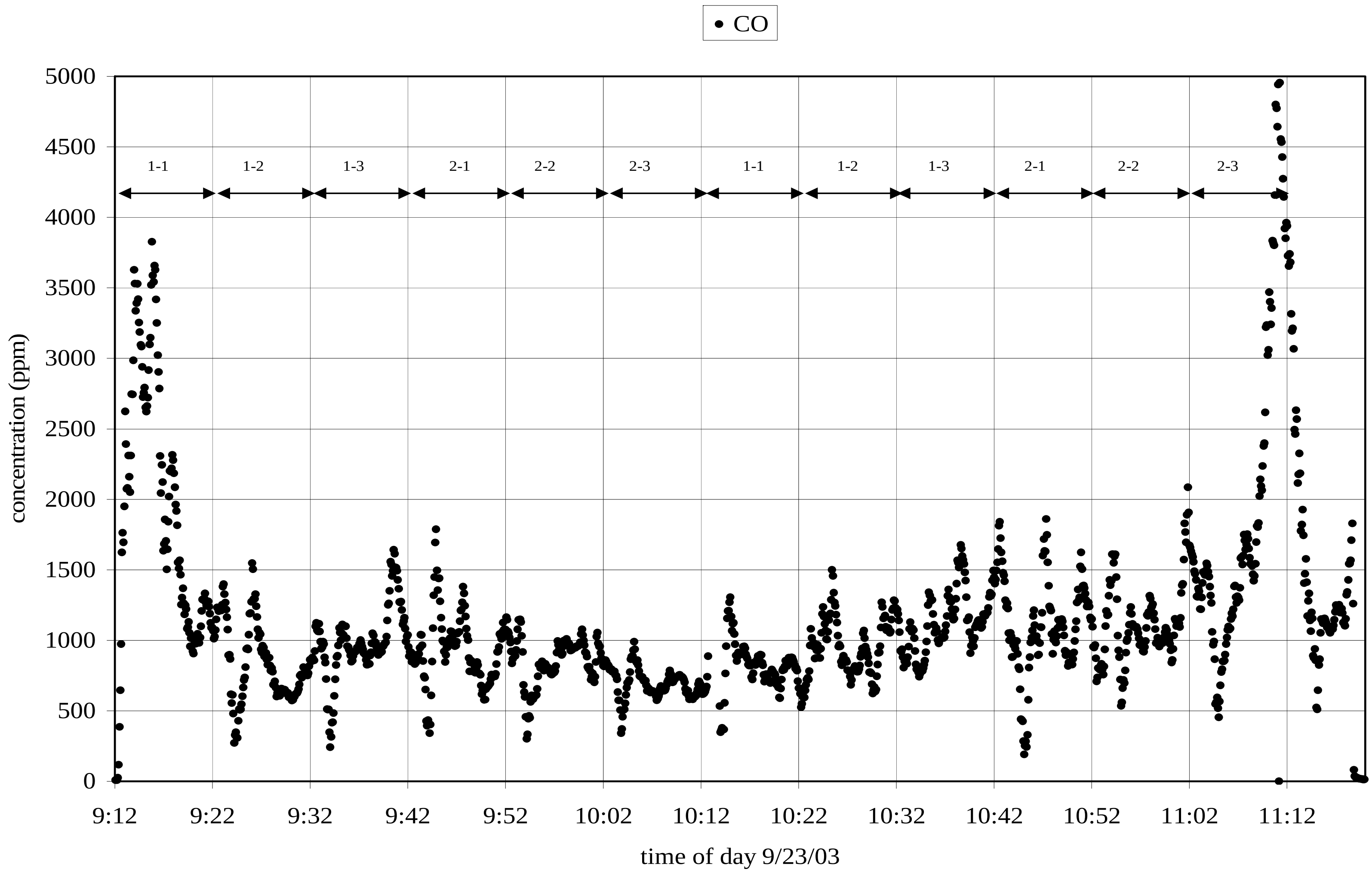


Figure Figure C17. CO concentrations recorded downstream of the air preheater in Boiler 1 firing bagasse on September 23, 2003, first and second sample period.

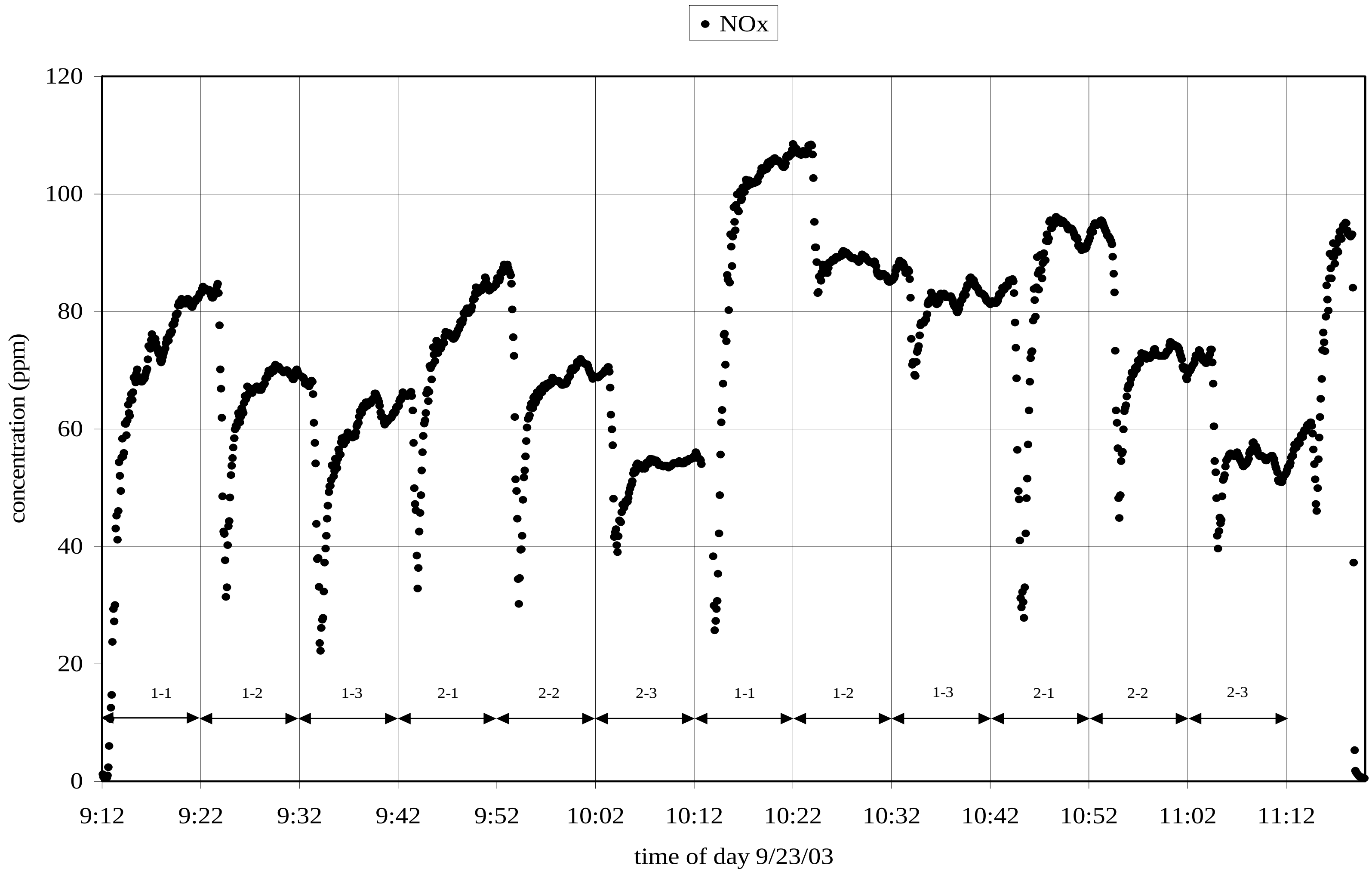


Figure C18. NOx concentrations recorded downstream of the air preheater in Boiler 1 firing bagasse on September 23, 2003, first and second sample period.

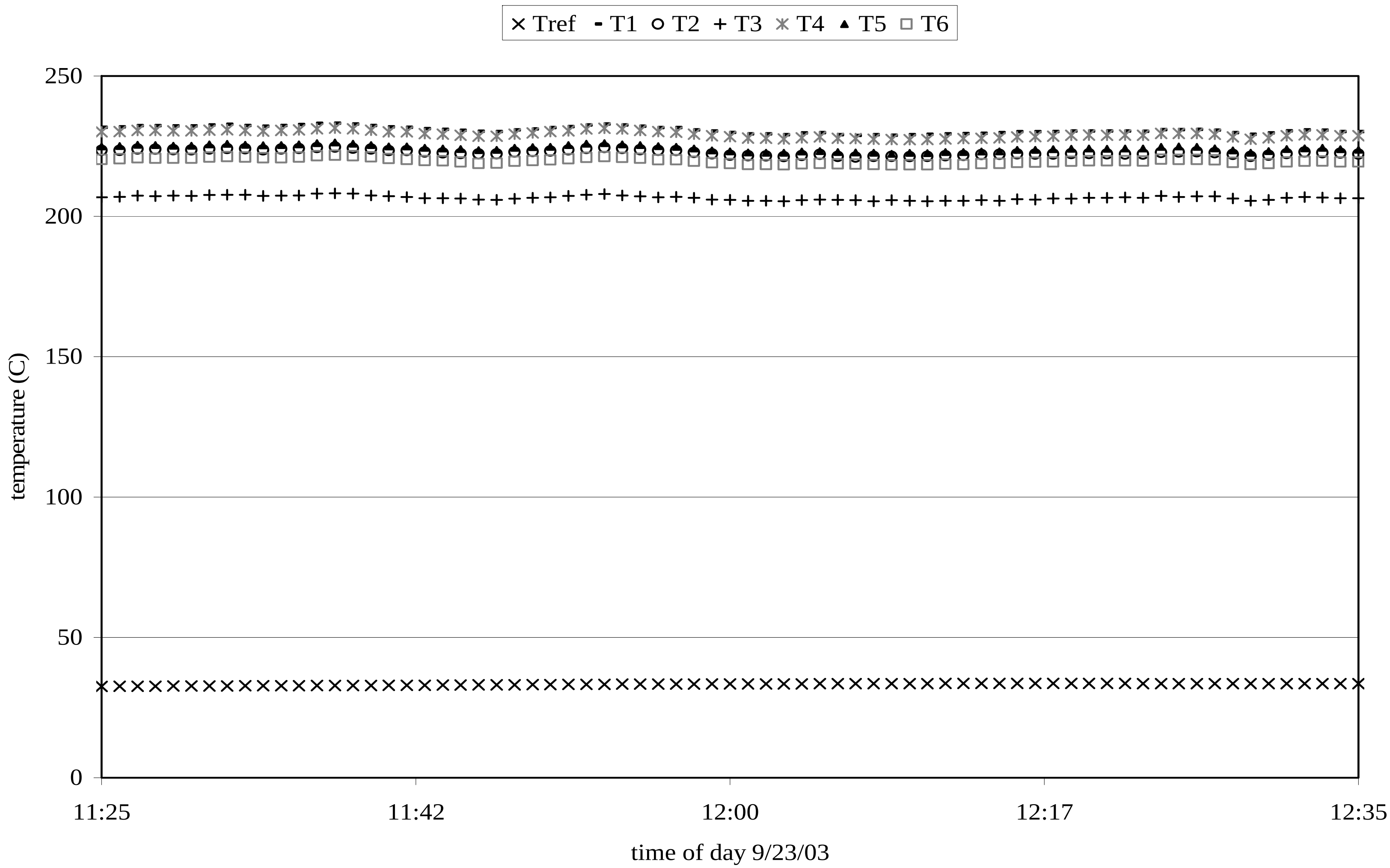


Figure C19. Temperatures recorded downstream of the air preheater in Boiler 1 firing bagasse on September 23, 2003, second sample period. Temperatures T1 though T6 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

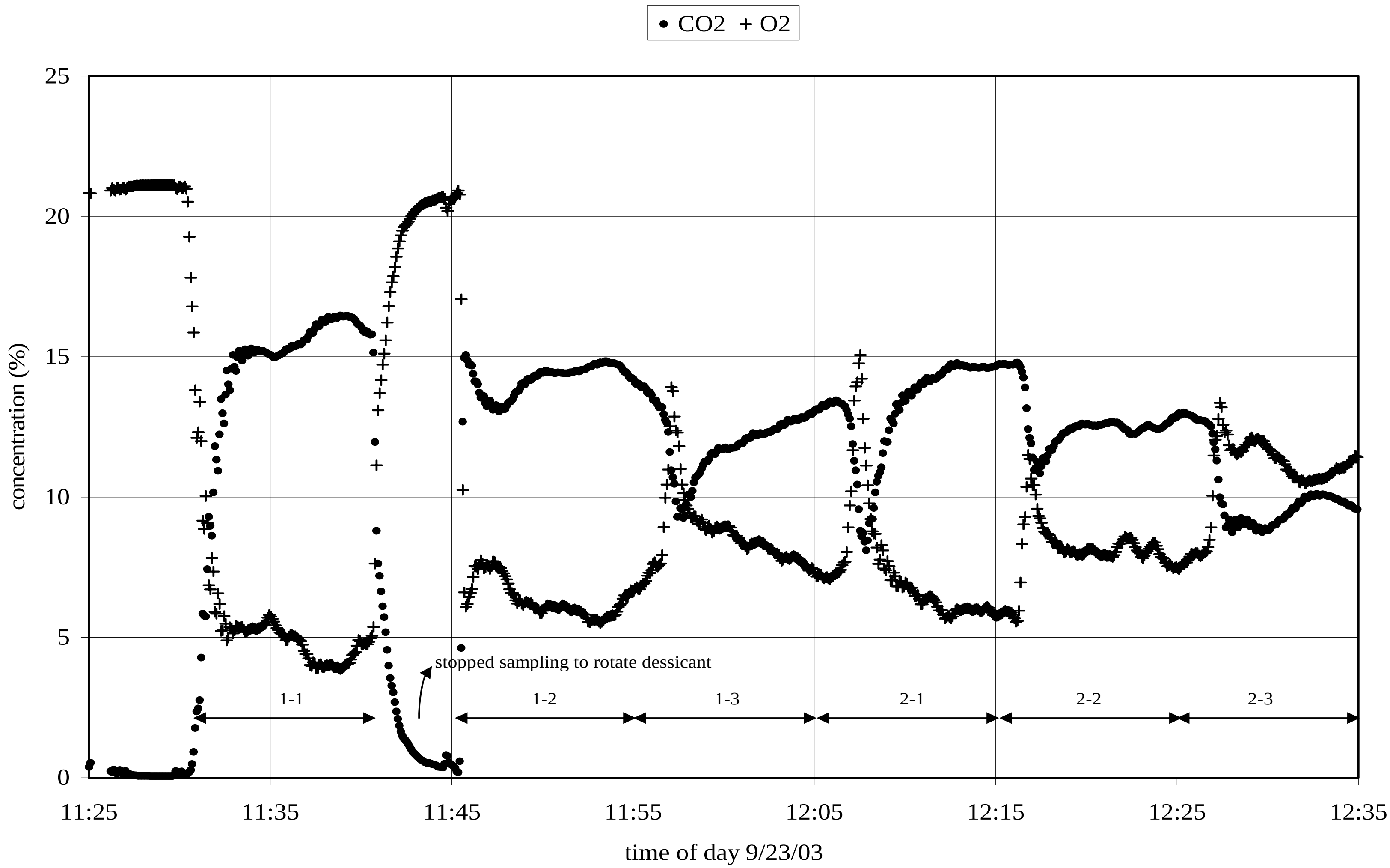


Figure C20. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 1 firing bagasse on September 23, 2003, third sample period.

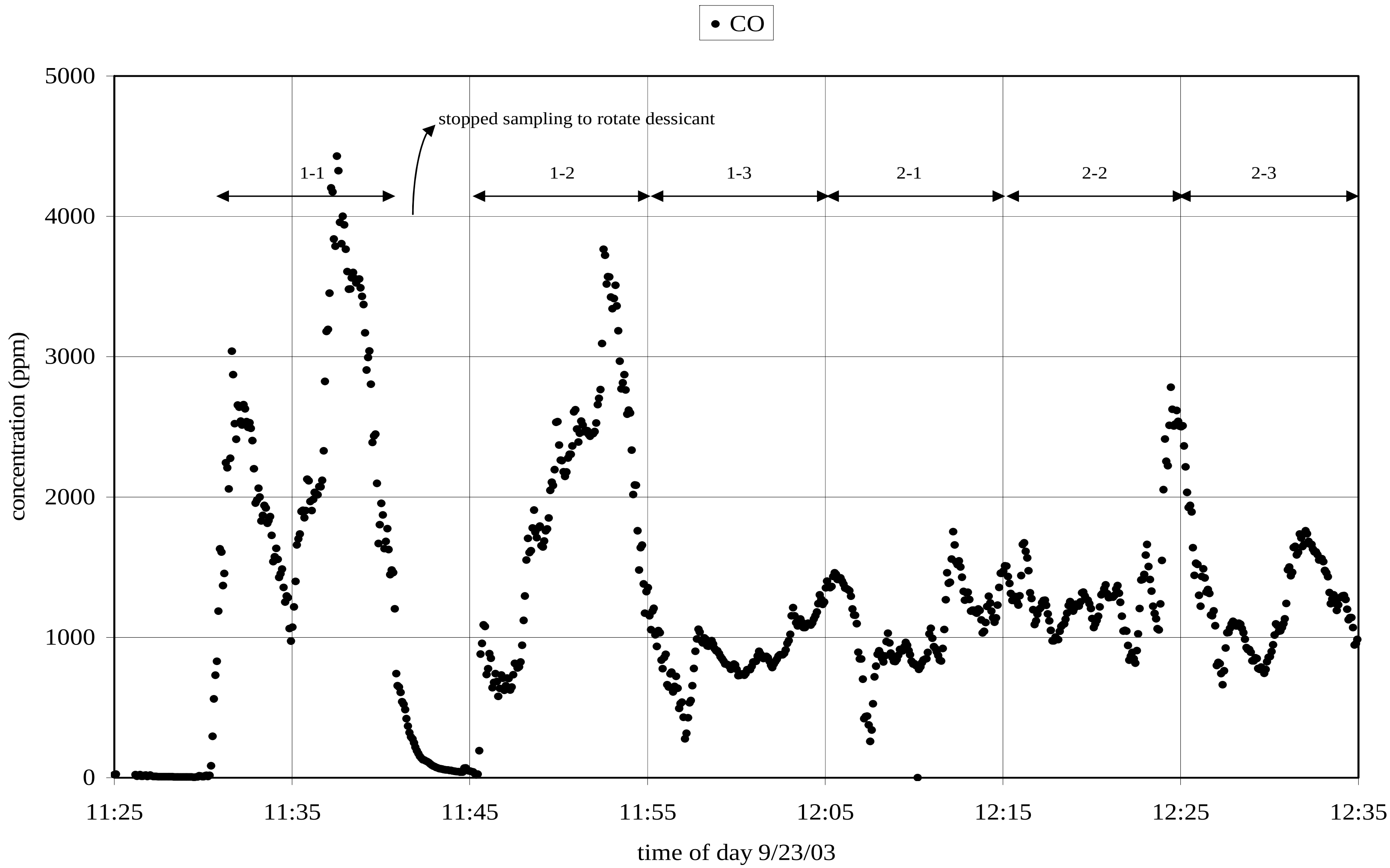


Figure C21. CO concentrations recorded downstream of the air preheater in Boiler 1 firing bagasse on September 23, 2003, third sample period.

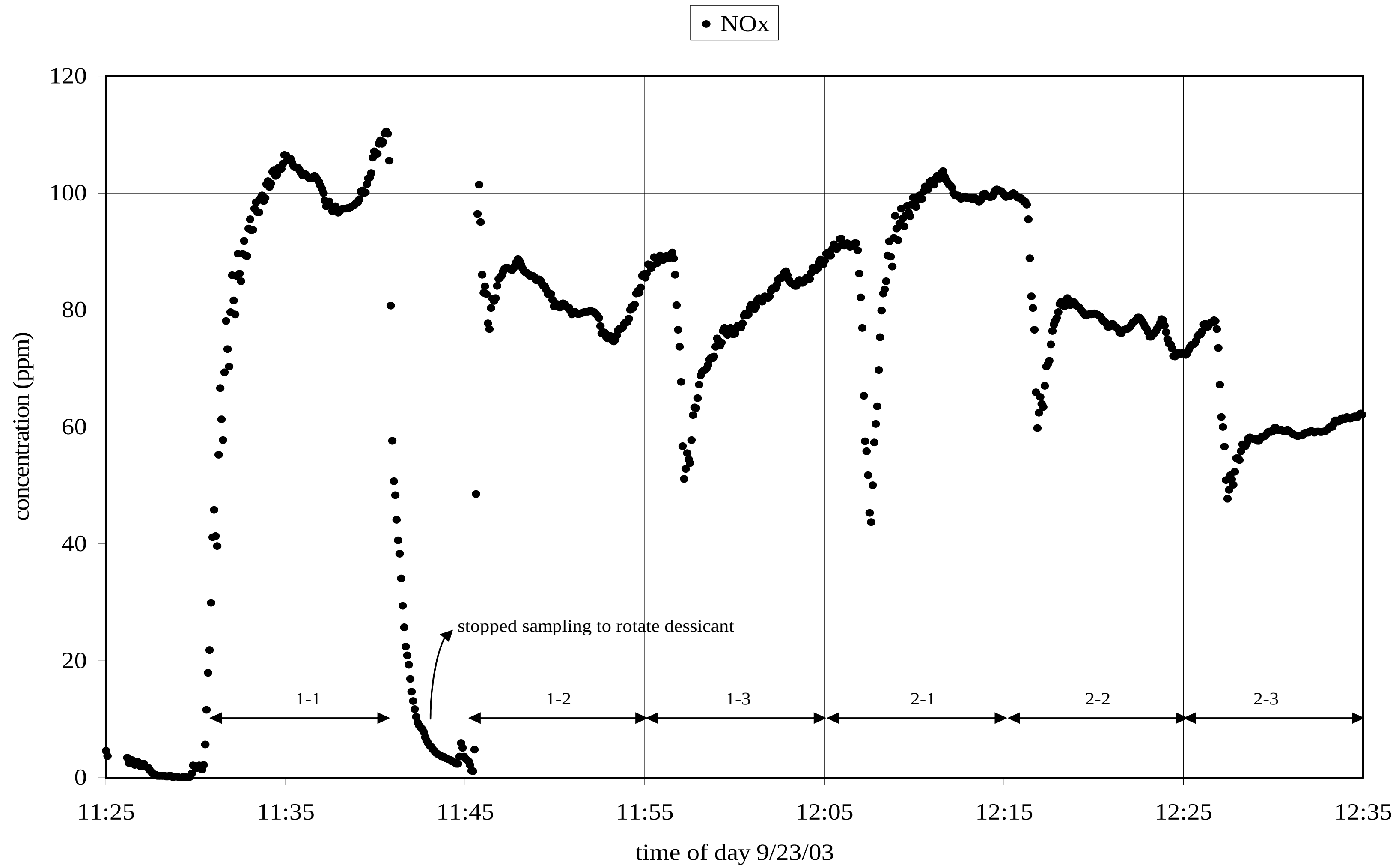


Figure C22. NOx concentrations recorded downstream of the air preheater in Boiler 1 firing bagasse on September 23, 2003, third sample period.

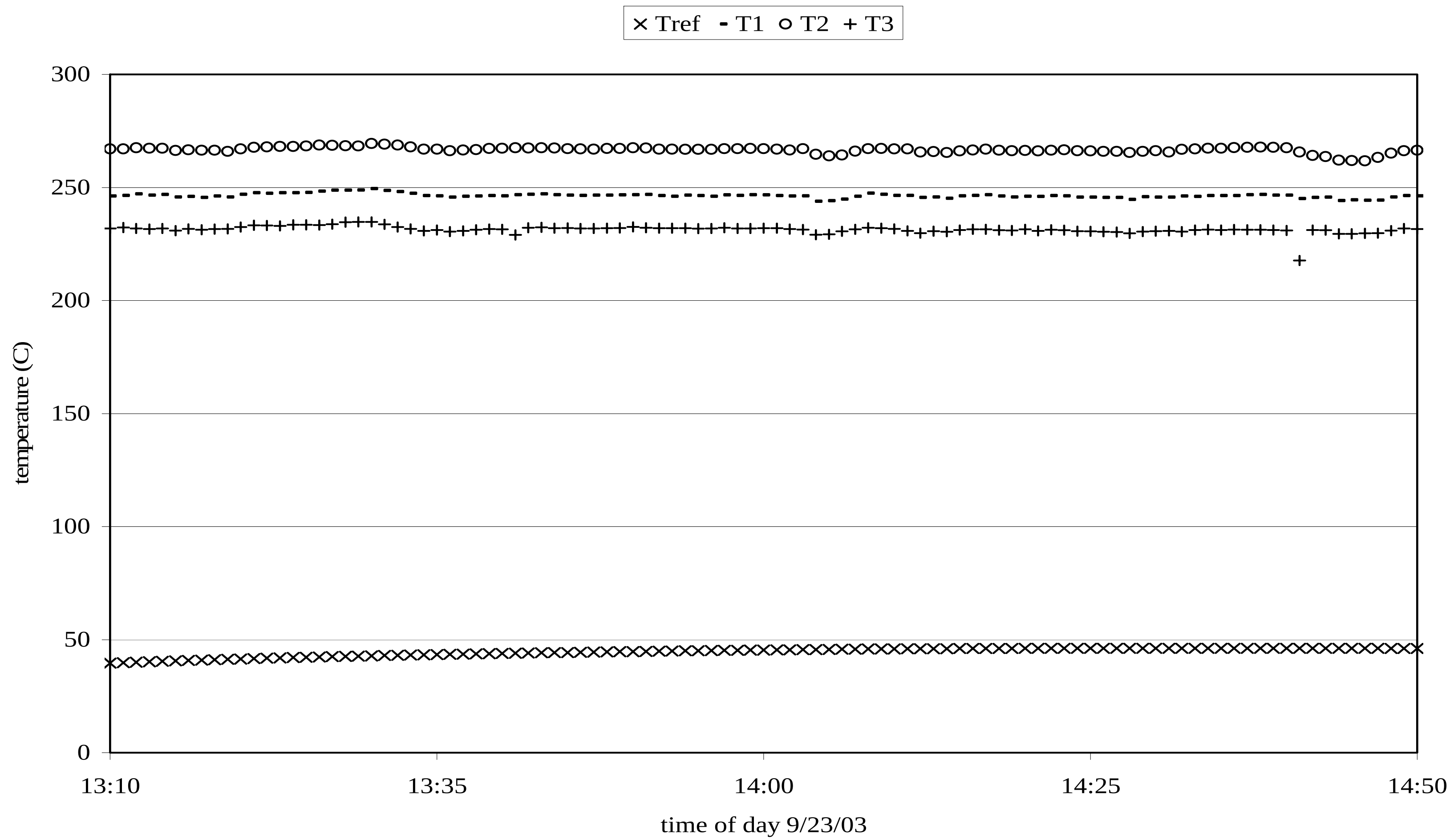


Figure C23. Temperatures recorded downstream of the air preheater in Boiler 2 firing bagasse on September 23, 2003, first sample period. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature

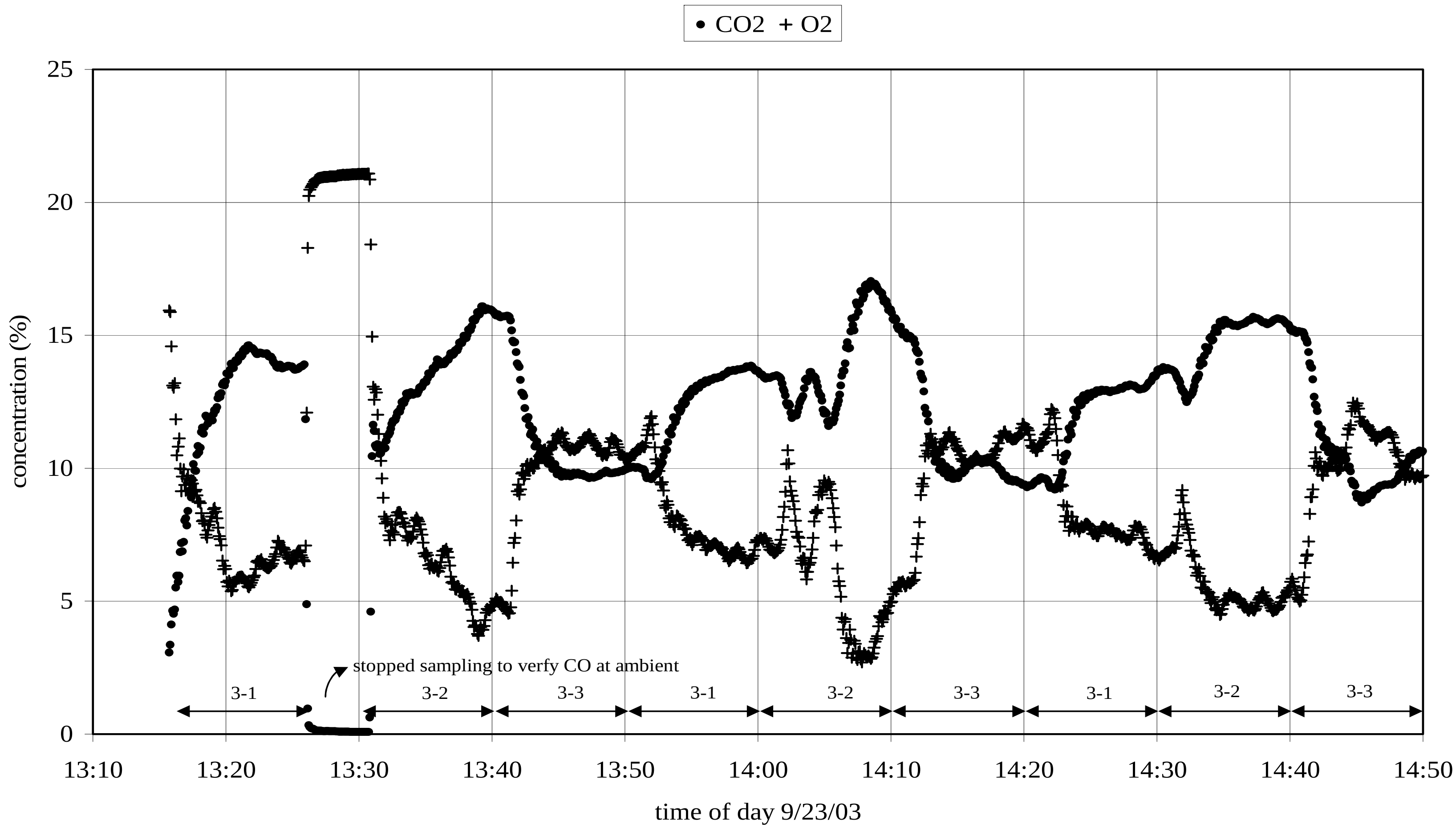


Figure C24. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 2 firing bagasse on September 23, 2003, three sample periods.

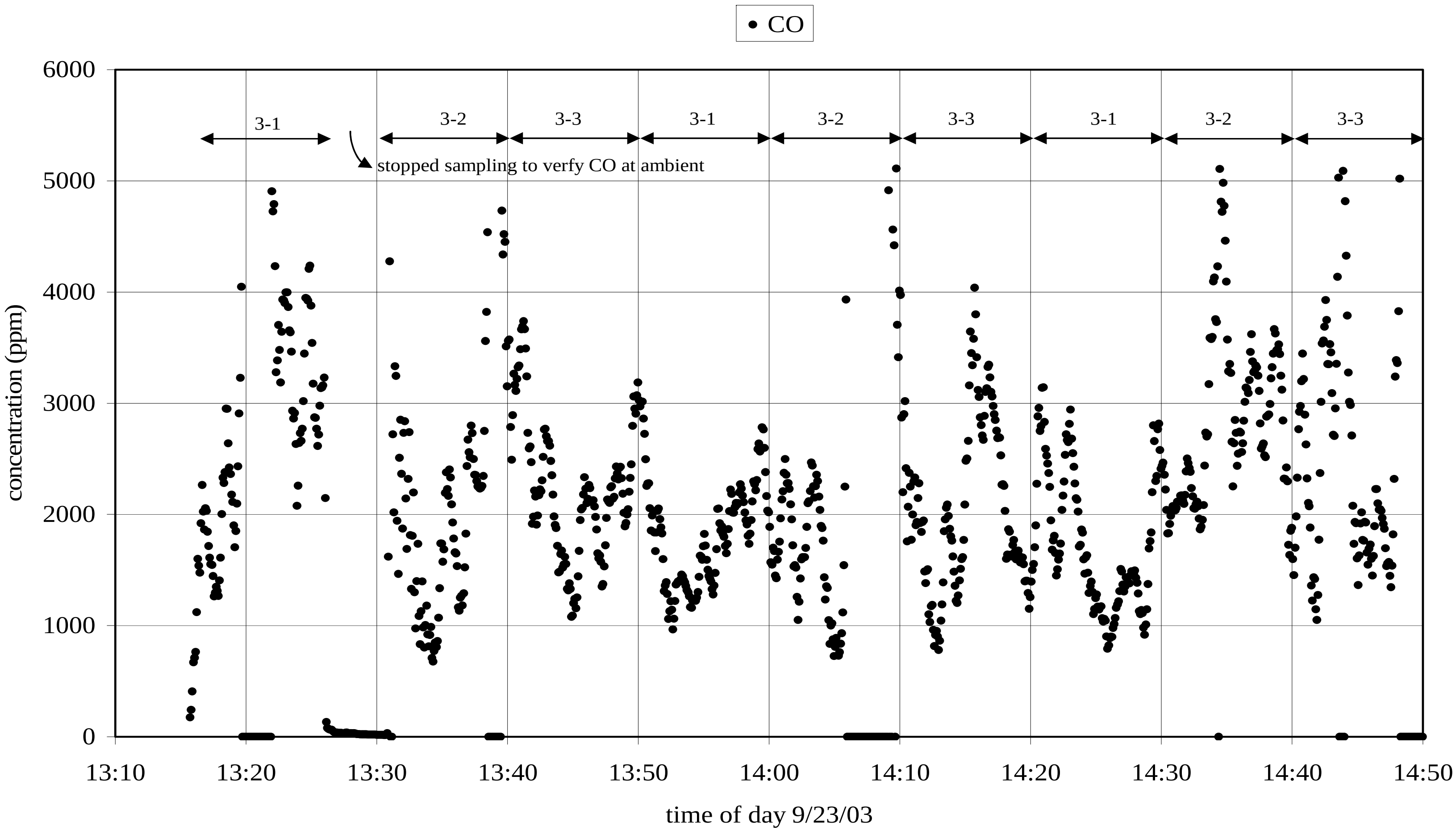


Figure C25. CO concentrations recorded downstream of the air preheater in Boiler 2 firing bagasse on September 23, 2003, three sample periods.

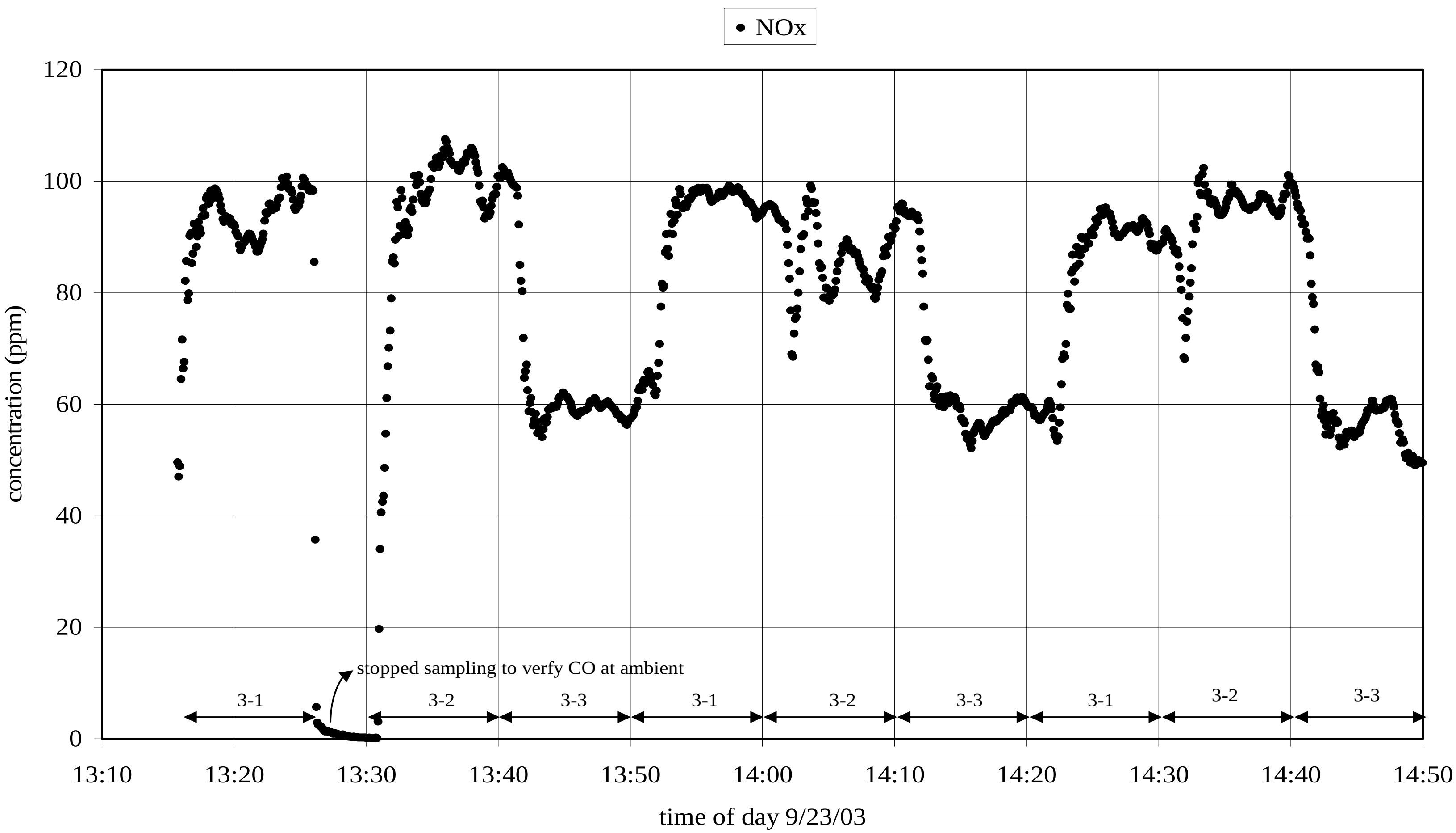


Figure C26. NOx concentrations recorded downstream of the air preheater in Boiler 2 firing bagasse on September 23, 2003, three sample periods.

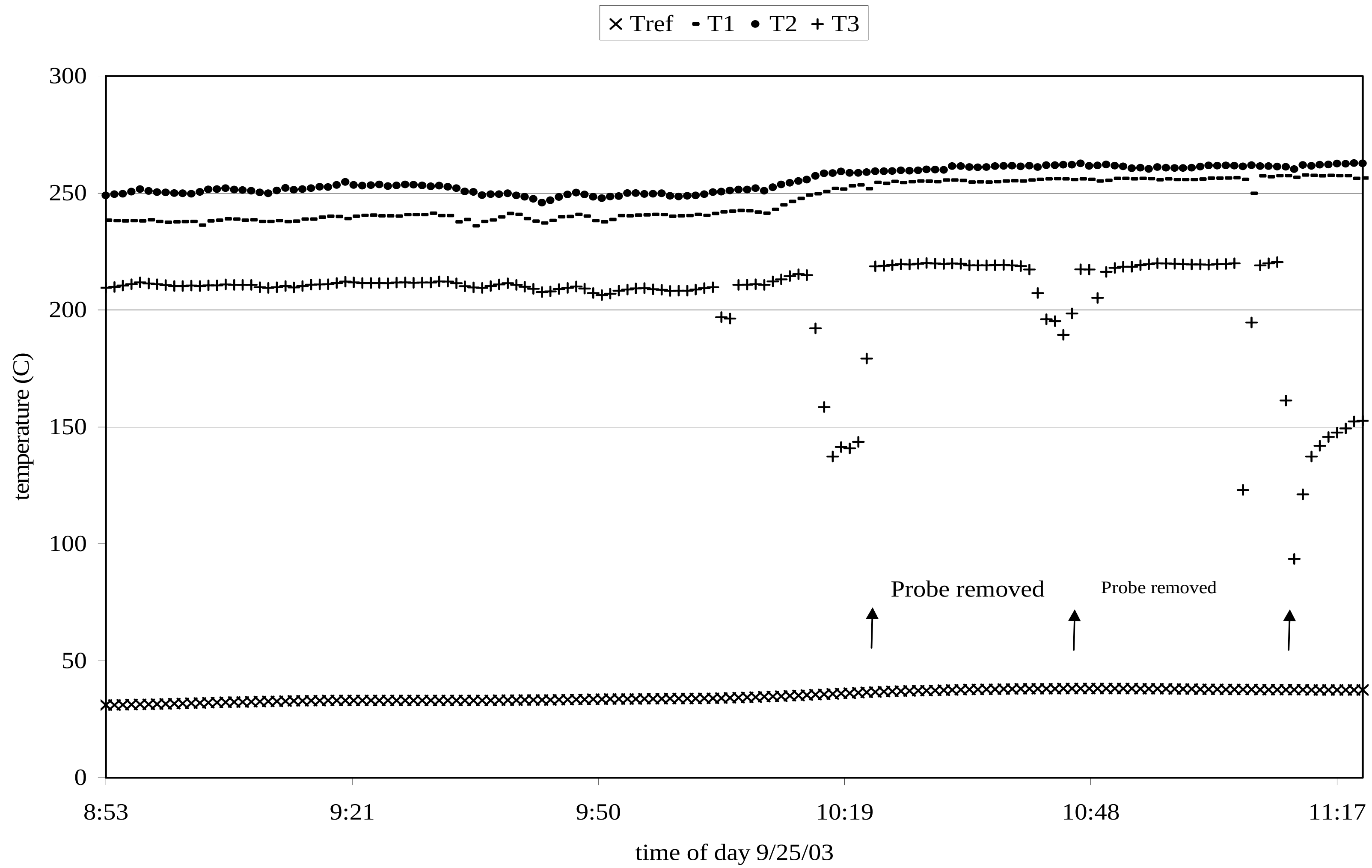


Figure C27. Temperatures recorded downstream of the air preheater in Boiler 3 firing bagasse on September 25, 2003. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

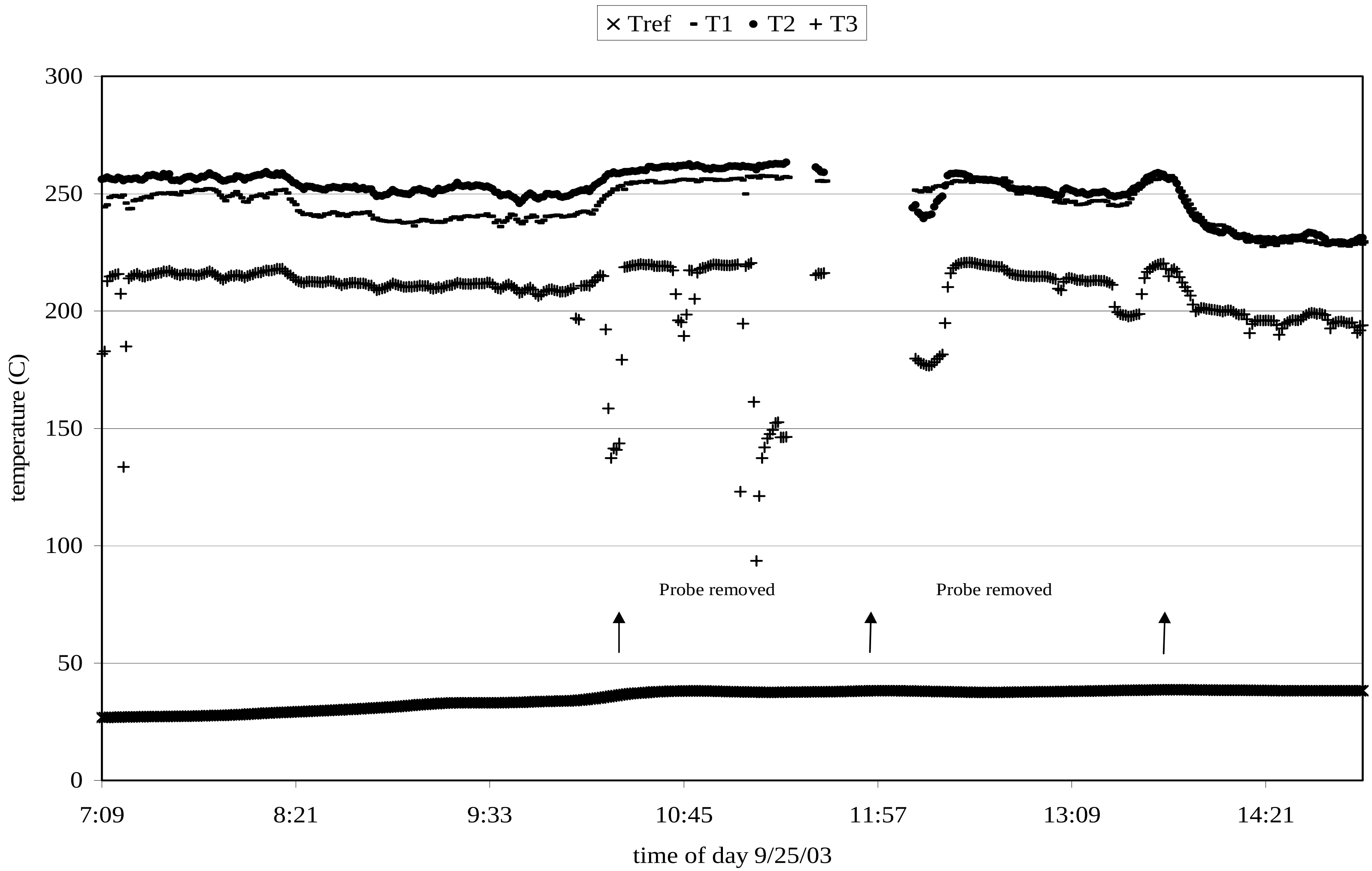


Figure C28. Temperatures recorded downstream of the air preheater in Boiler 3 firing bagasse on September 25, 2003, first sample period. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

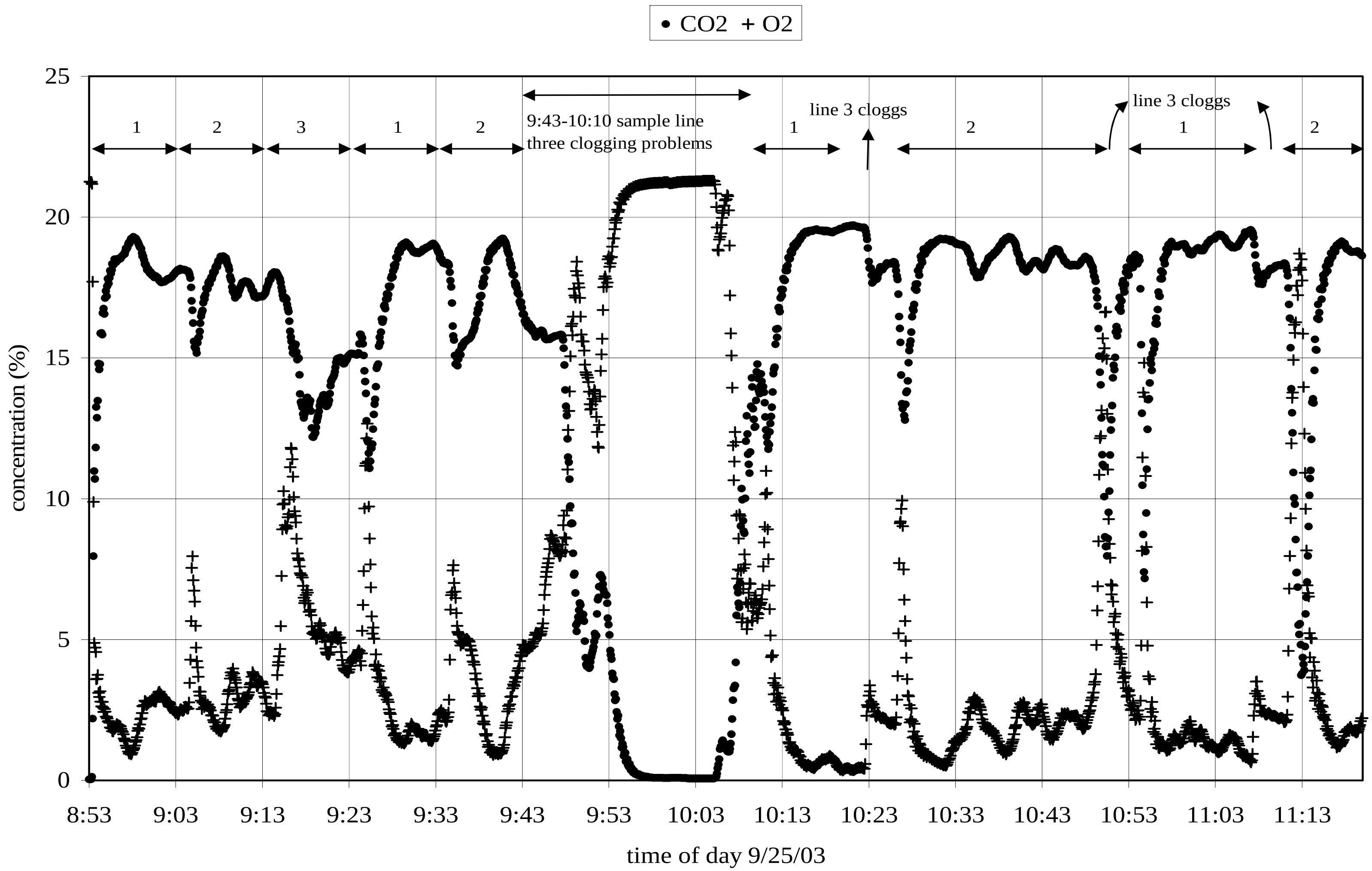


Figure Figure C29. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 3 firing bagasse on September 25, 2003, first sample period.

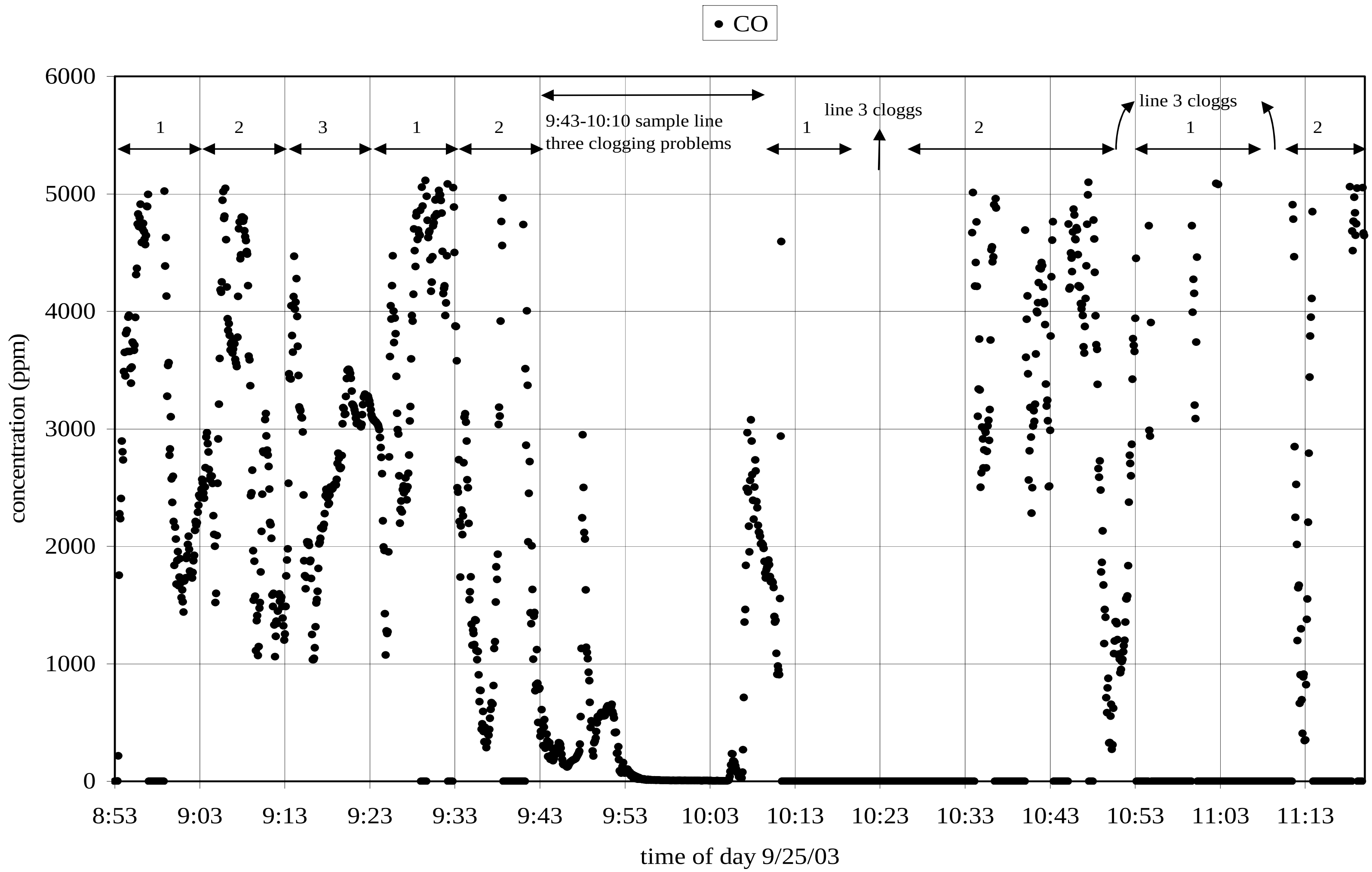


Figure C30. CO concentrations recorded downstream of the air preheater in Boiler 3 firing bagasse on September 25, 2003, first sample period.

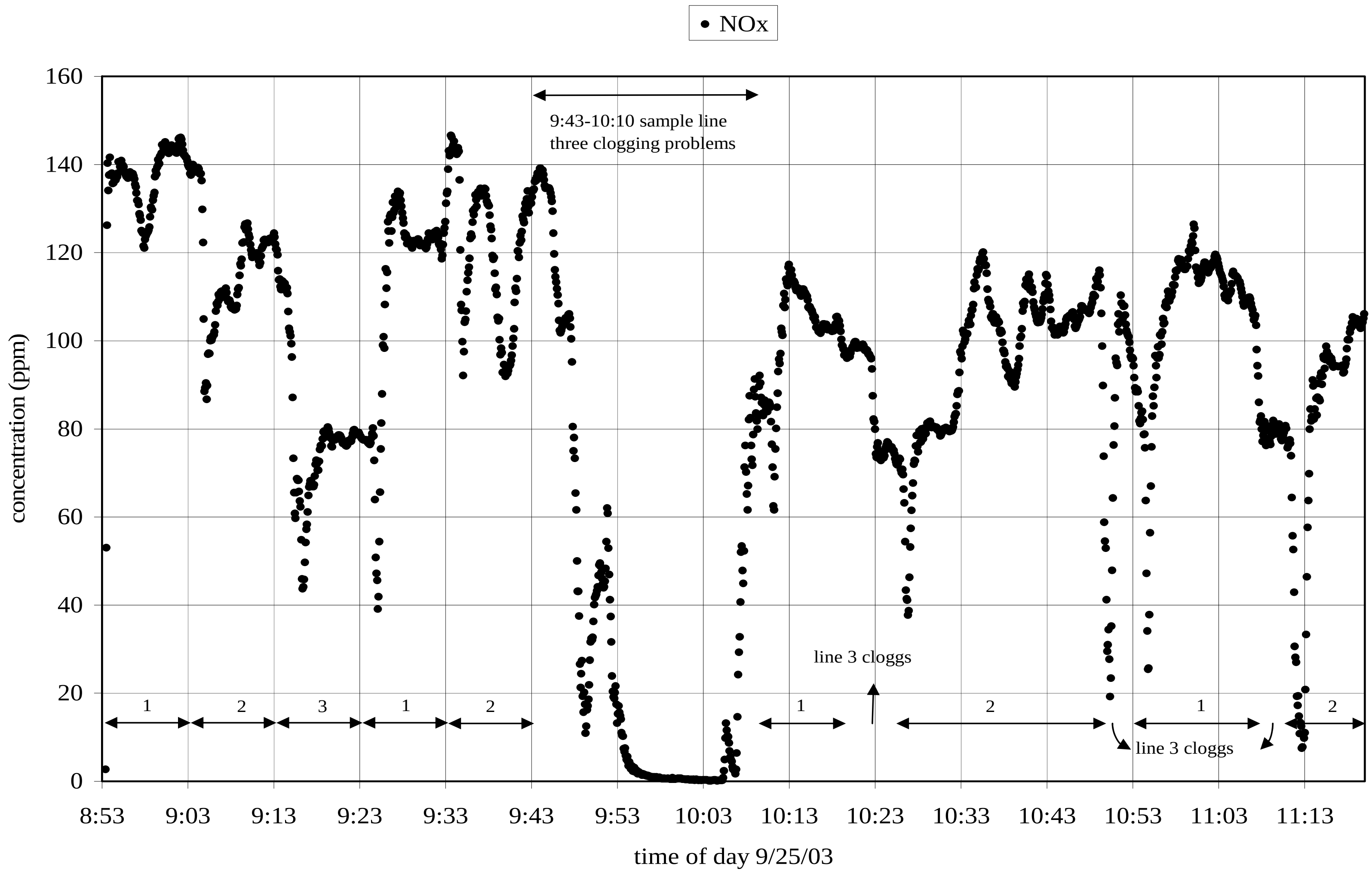


Figure C31. NOx concentrations recorded downstream of the air preheater in Boiler 3 firing bagasse on September 25, 2003, first sample period.

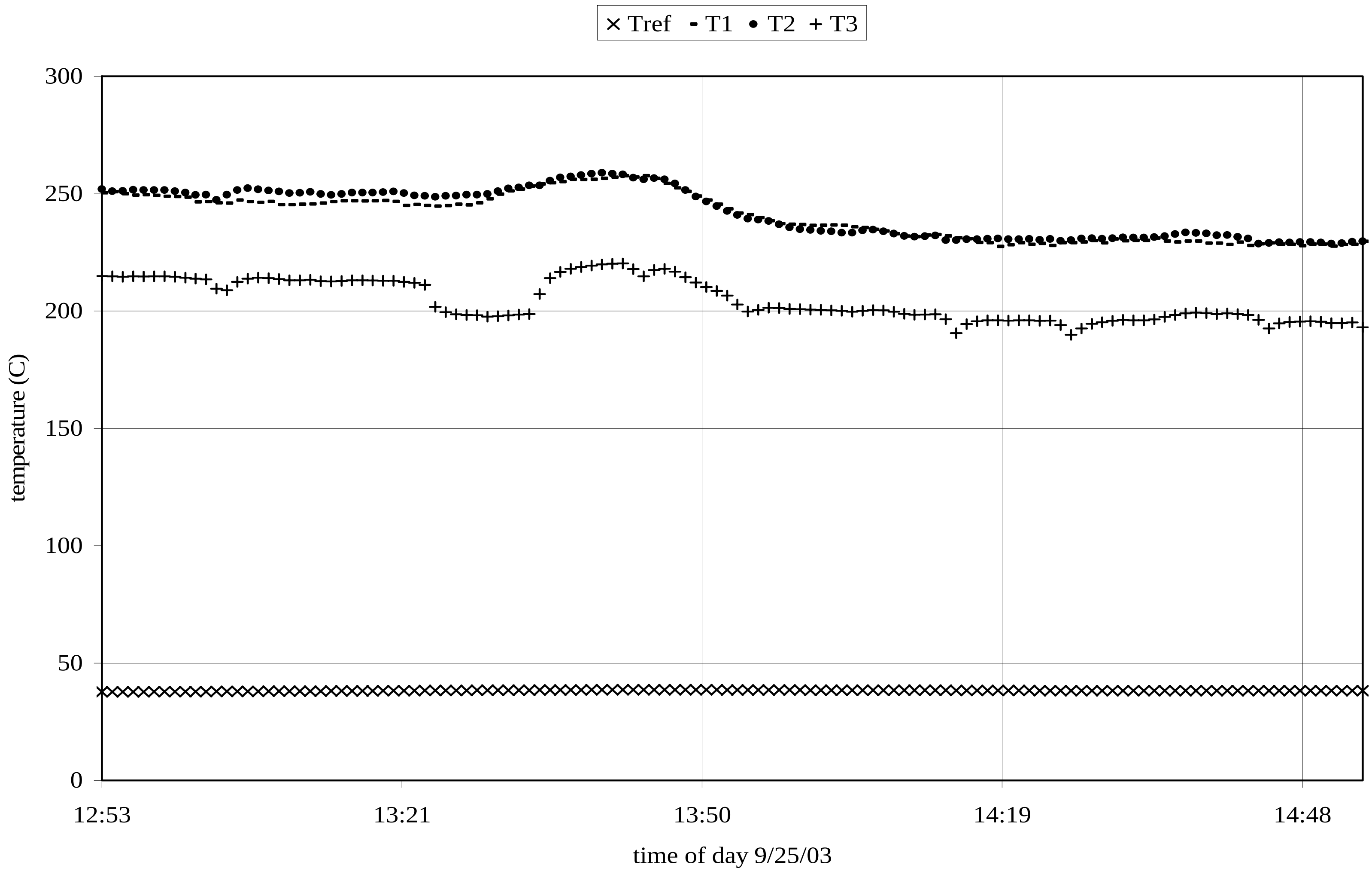


Figure C32. Temperatures recorded downstream of the air preheater in Boiler 3 firing bagasse on September 25, 2003, second sample period. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

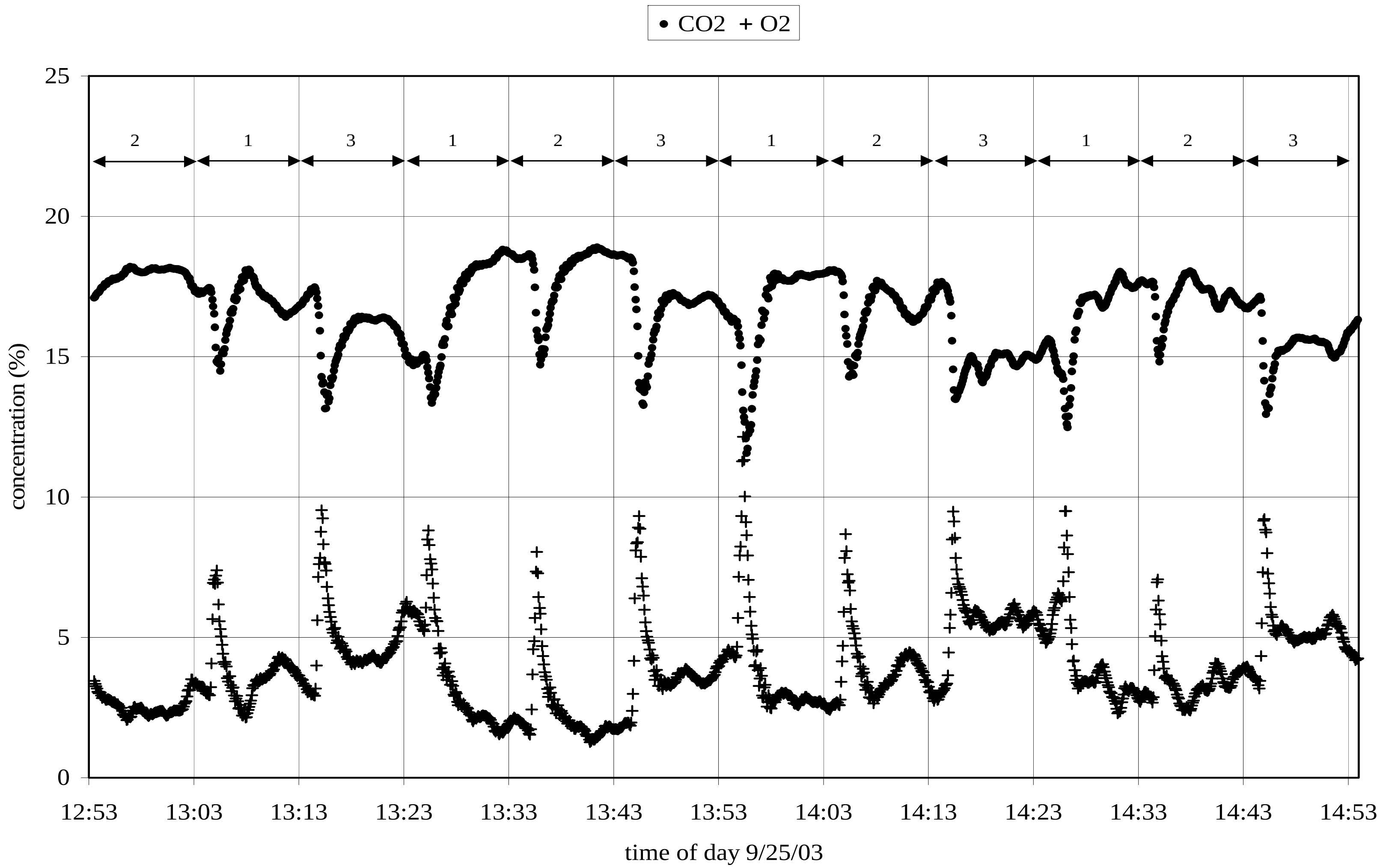


Figure C33. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 3 firing bagasse on September 25, 2003, second sample period.

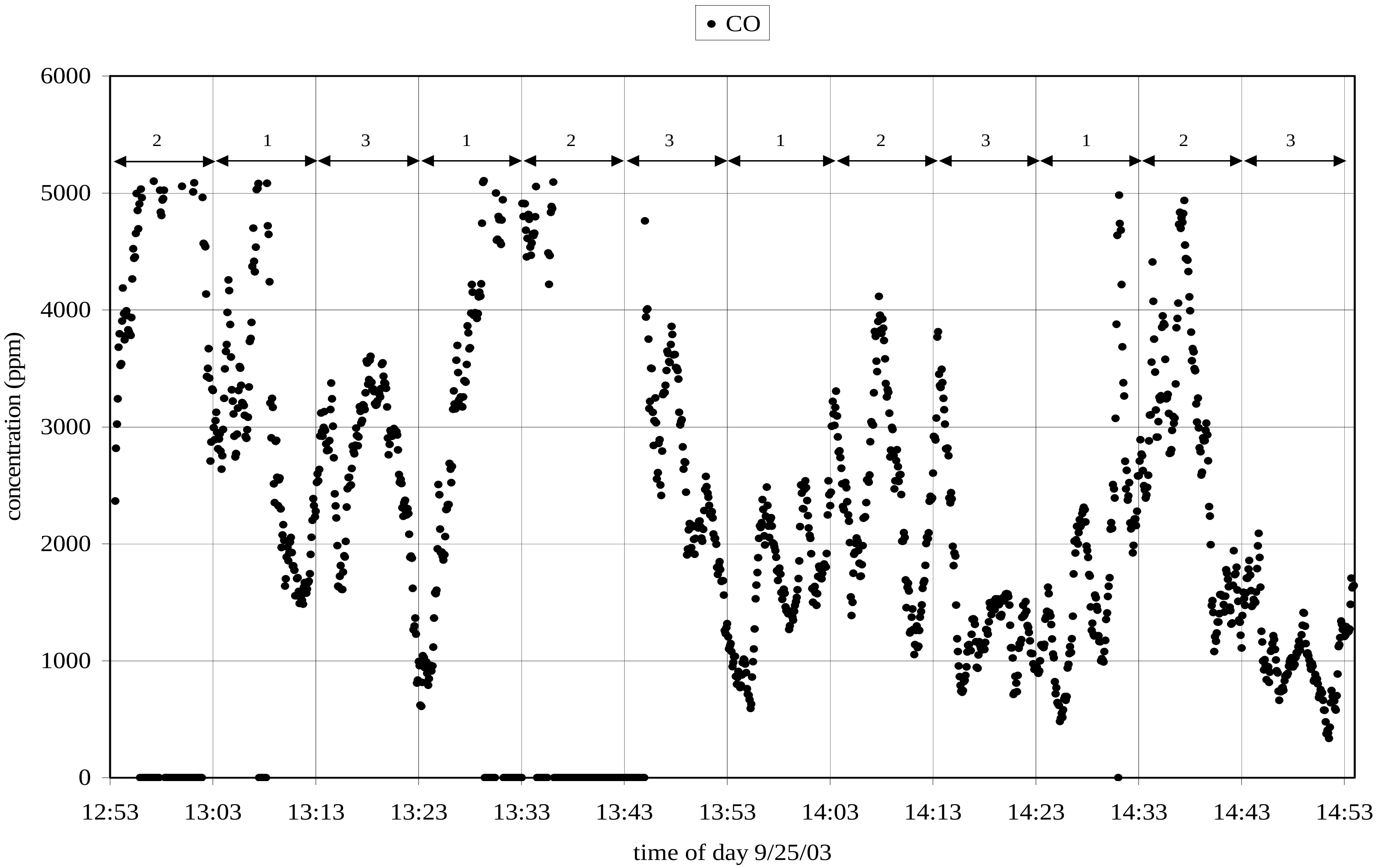


Figure C34. CO concentrations recorded downstream of the air preheater in Boiler 3 firing bagasse on September 25, 2003, second sample period.

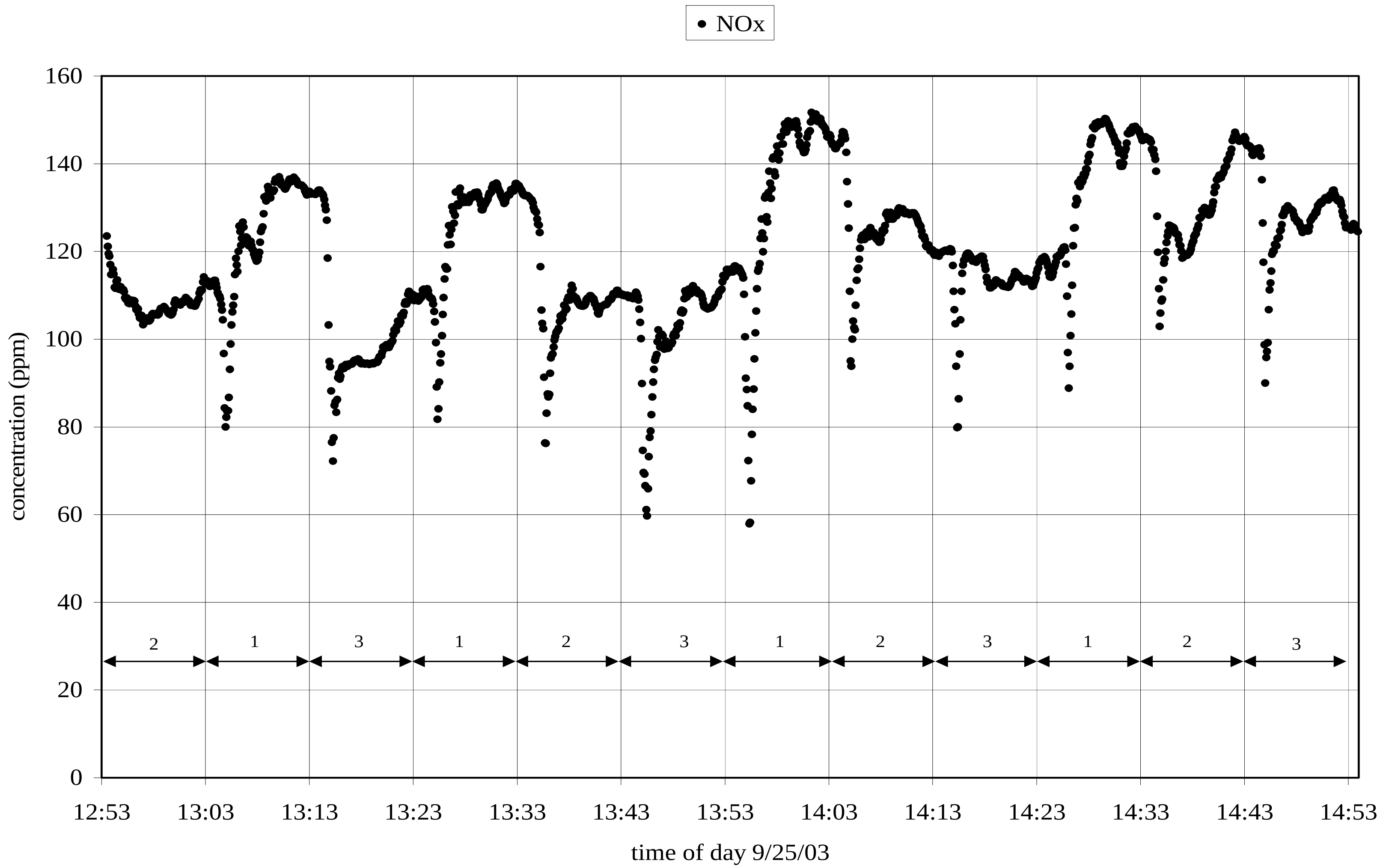


Figure C35. NOx concentrations recorded downstream of the air preheater in Boiler 3 firing bagasse on September 25, 2003, second sample period.

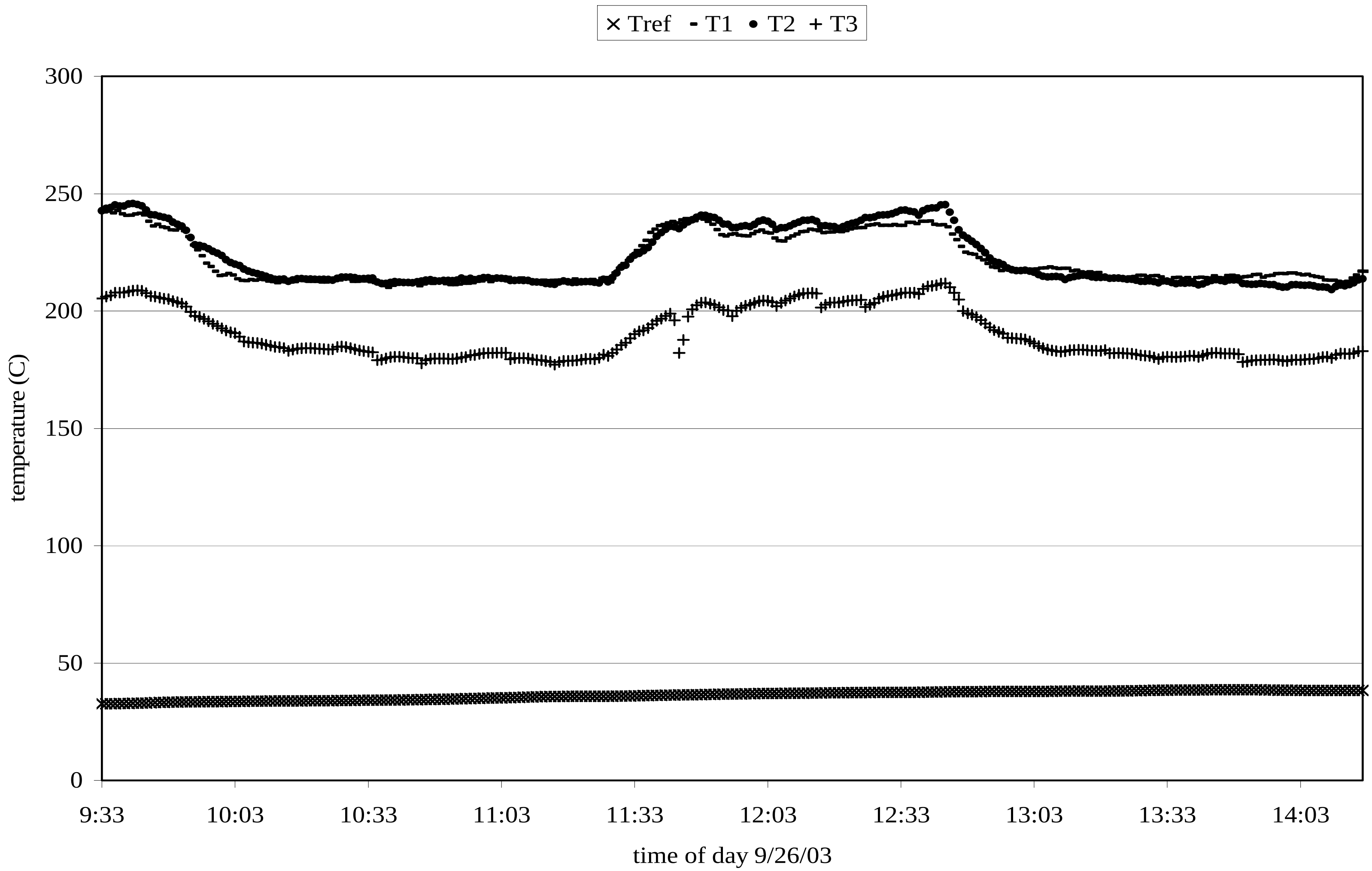


Figure C36. Temperatures recorded downstream of the air preheater in Boiler 3 firing coal on September 26, 2003. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

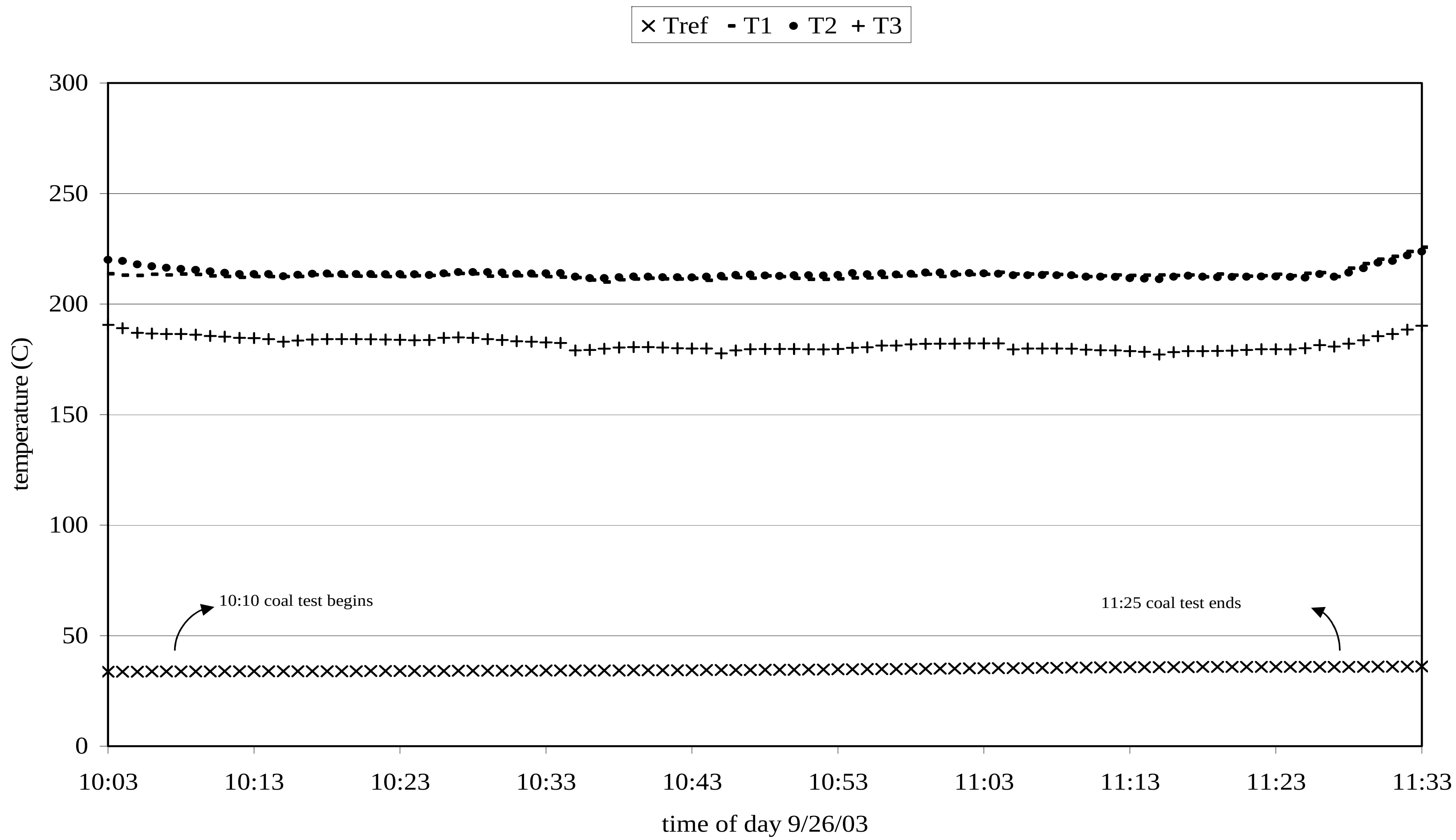


Figure C37. Temperatures recorded downstream of the air preheater in Boiler 3 firing coal on September 26, 2003, first sample period. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

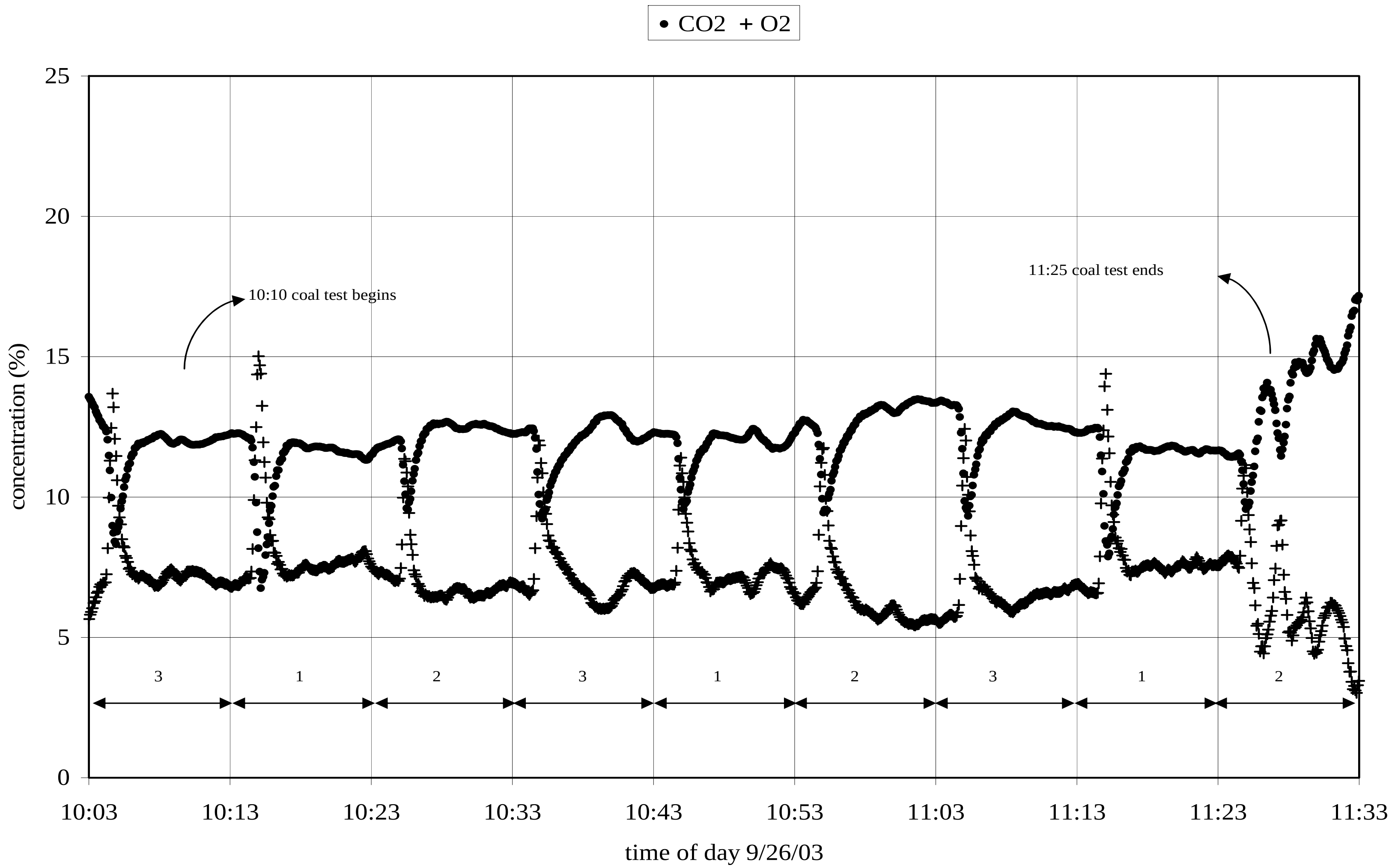


Figure C39. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 3 firing coal on September 26, 2003, first sample period.

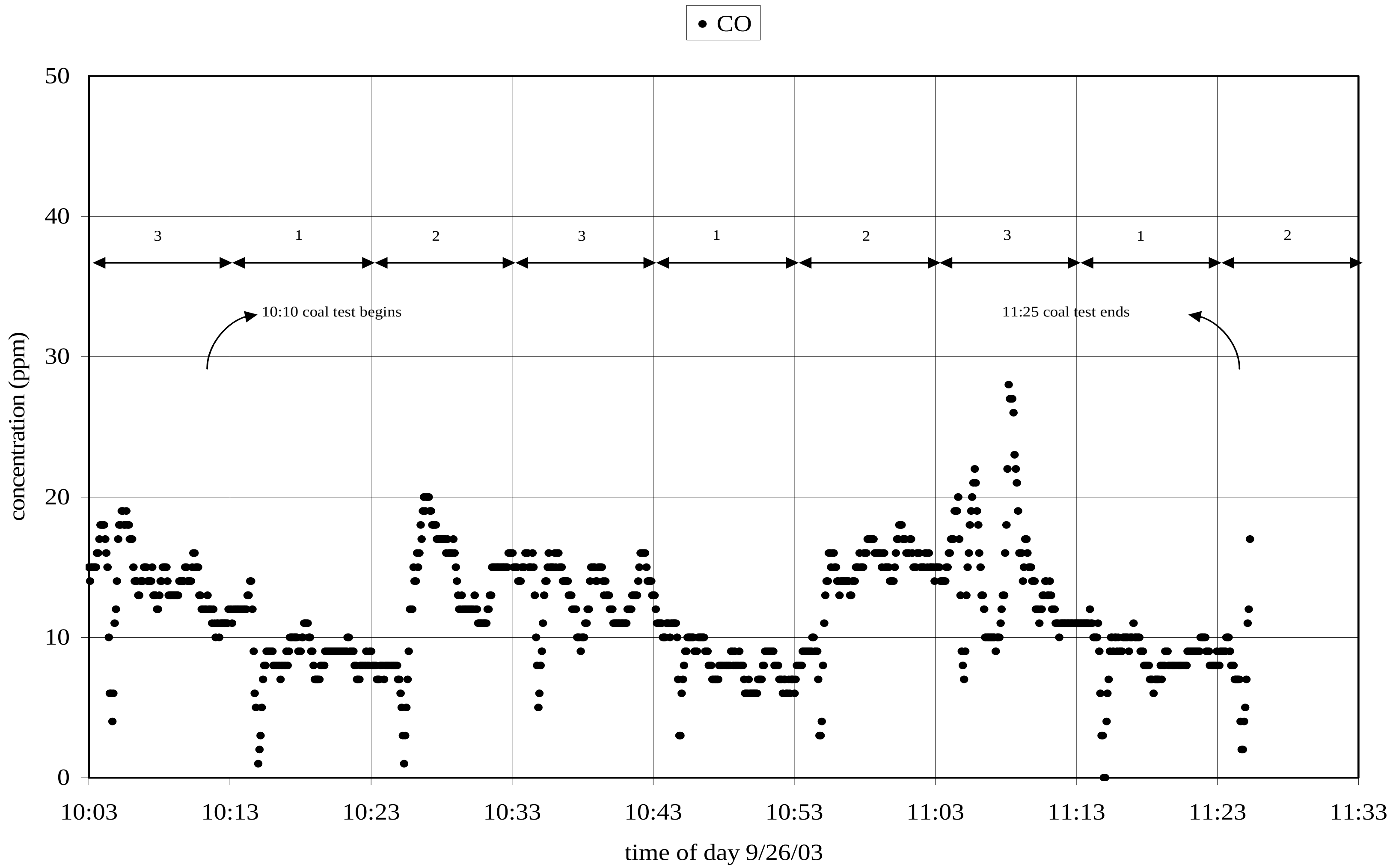


Figure C40. CO concentrations recorded downstream of the air preheater in Boiler 3 firing coal on September 26, 2003, first sample period.

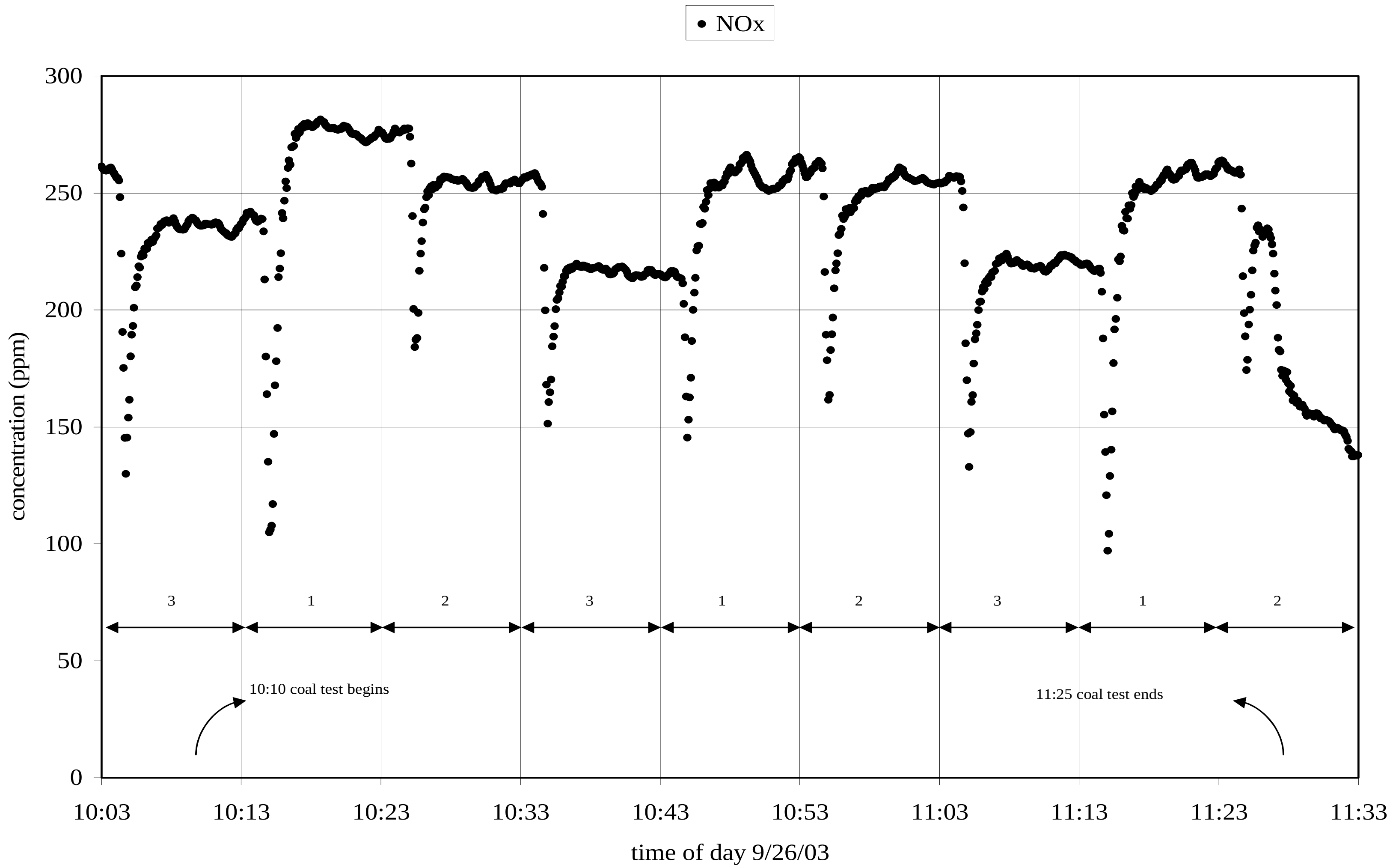


Figure C41. NOx concentrations recorded downstream of the air preheater in Boiler 3 firing coal on September 26, 2003, first sample period.

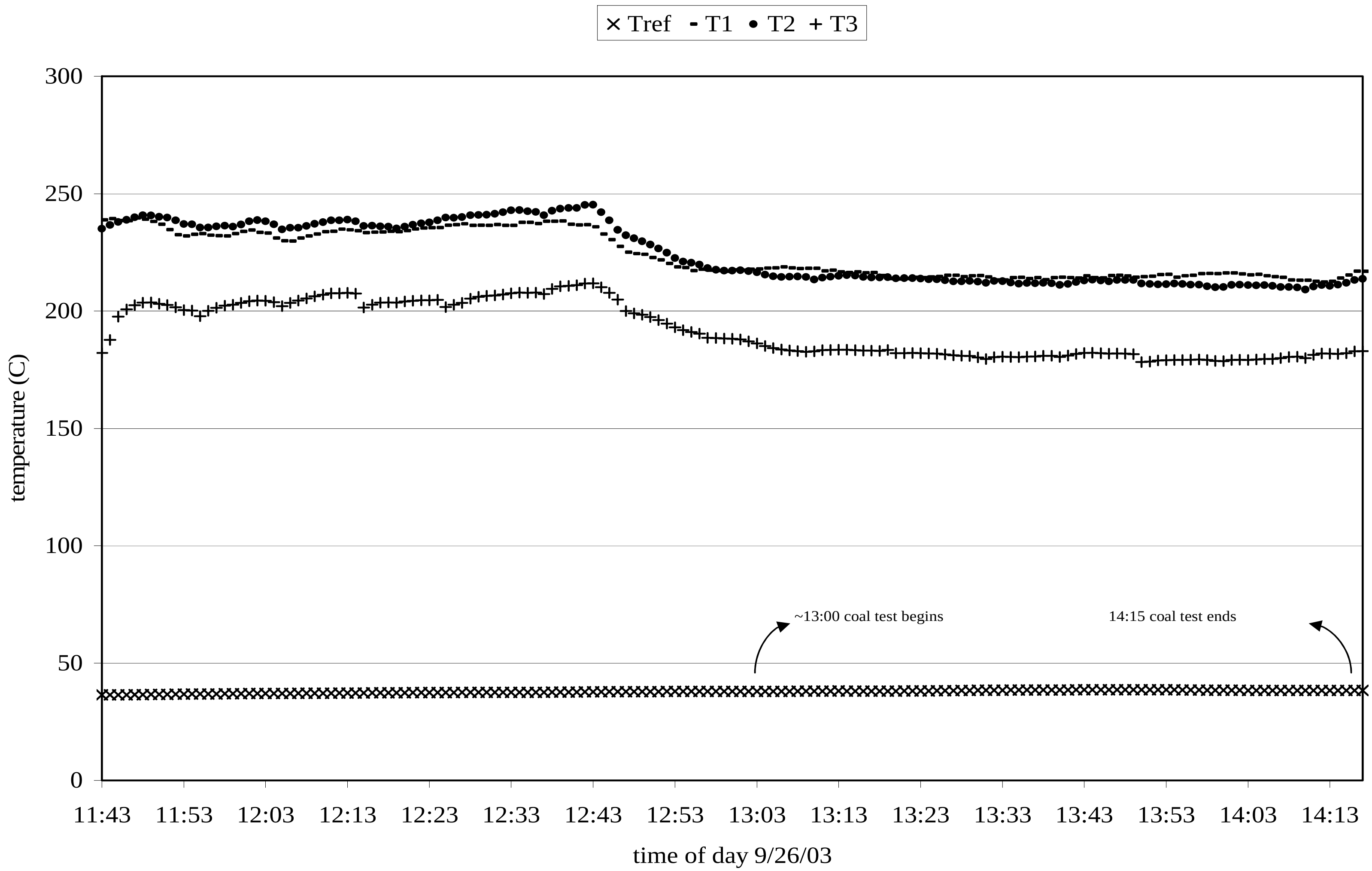


Figure C41. Temperatures recorded downstream of the air preheater in Boiler 3 firing coal on September 26, 2003, second sample period. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

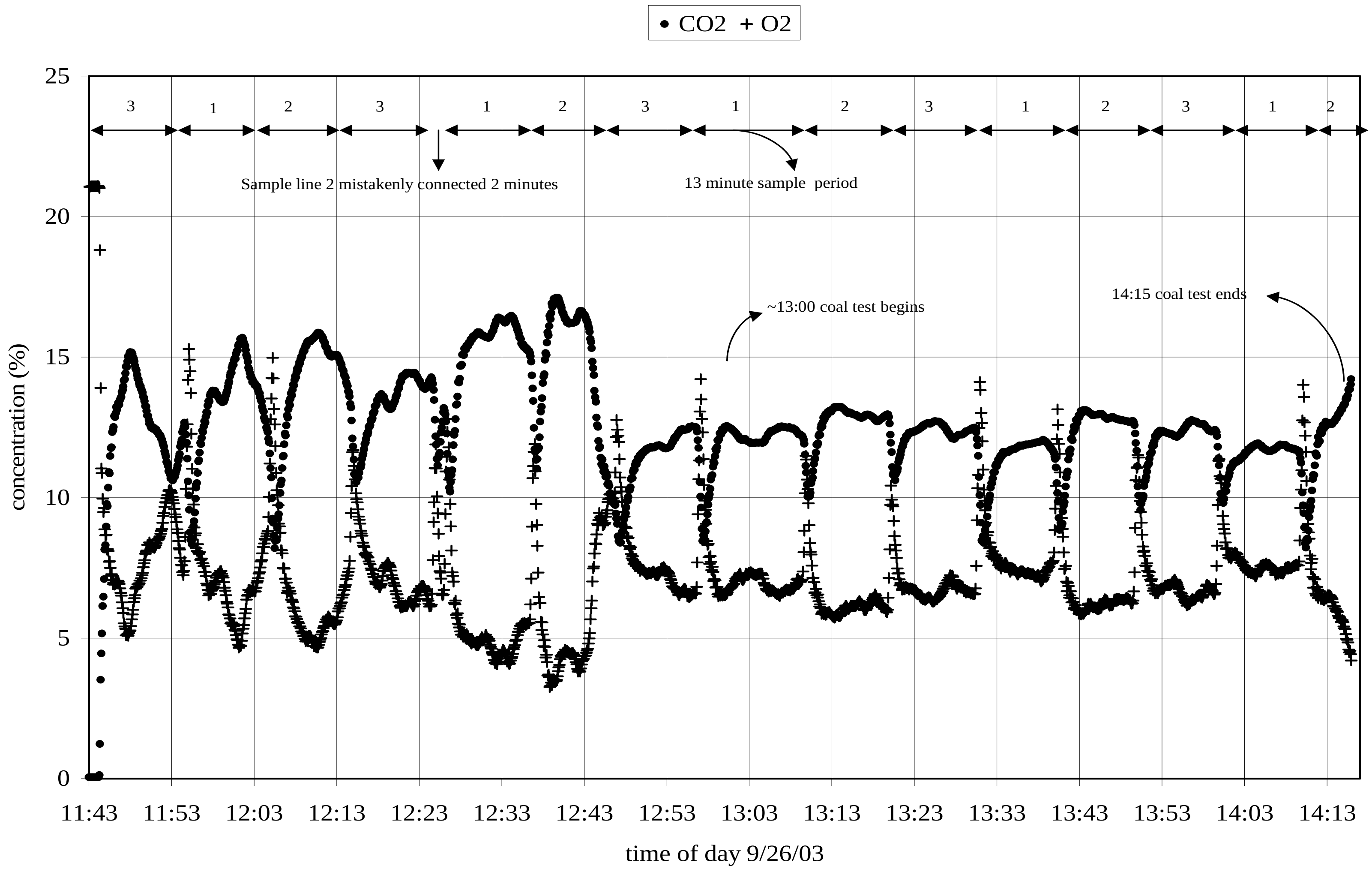


Figure C42. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 3 firing coal on September 26, 2003, second sample period.

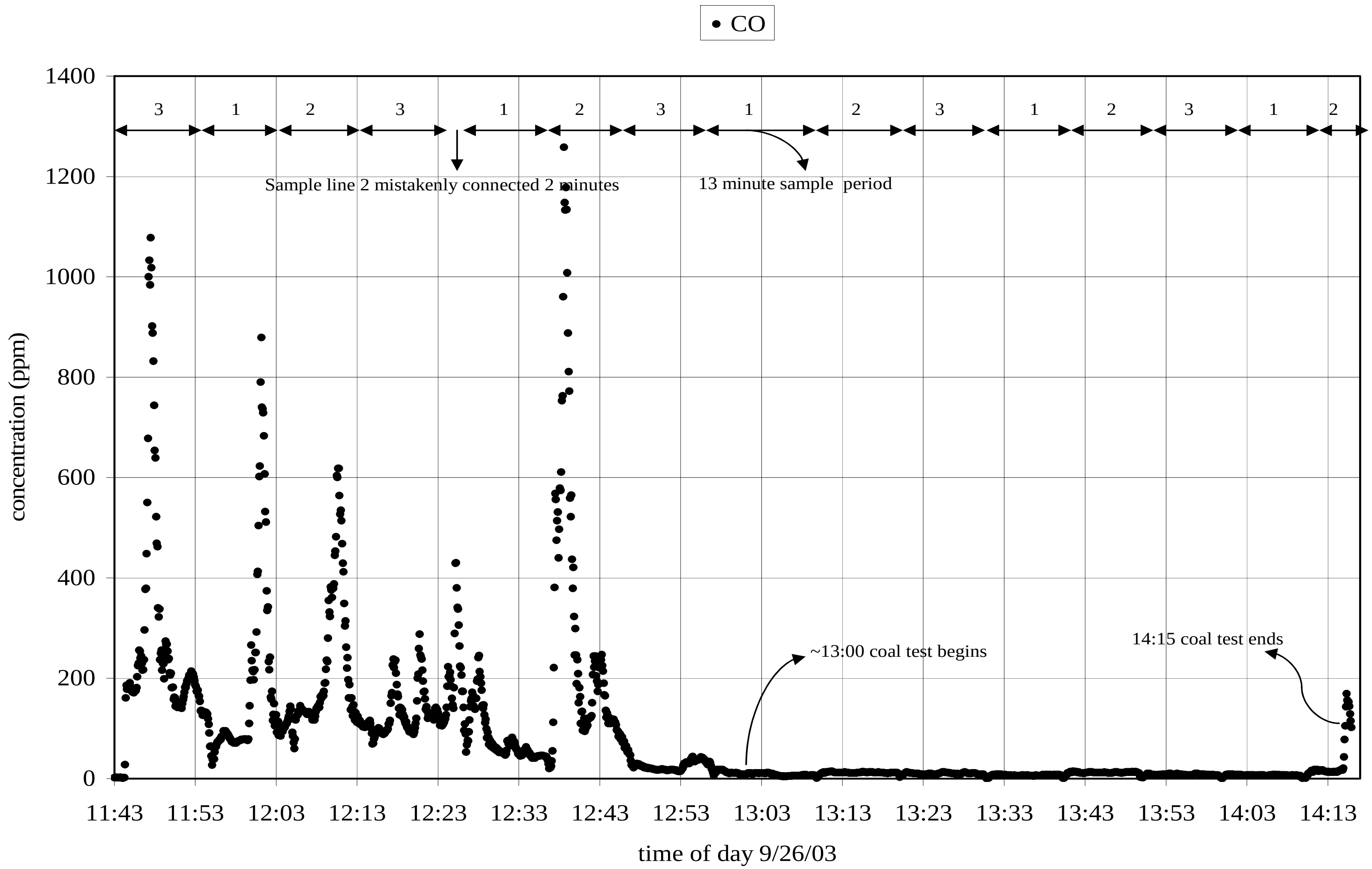


Figure C43. CO concentrations recorded downstream of the air preheater in Boiler 3 firing coal on September 26, 2003, second sample period.

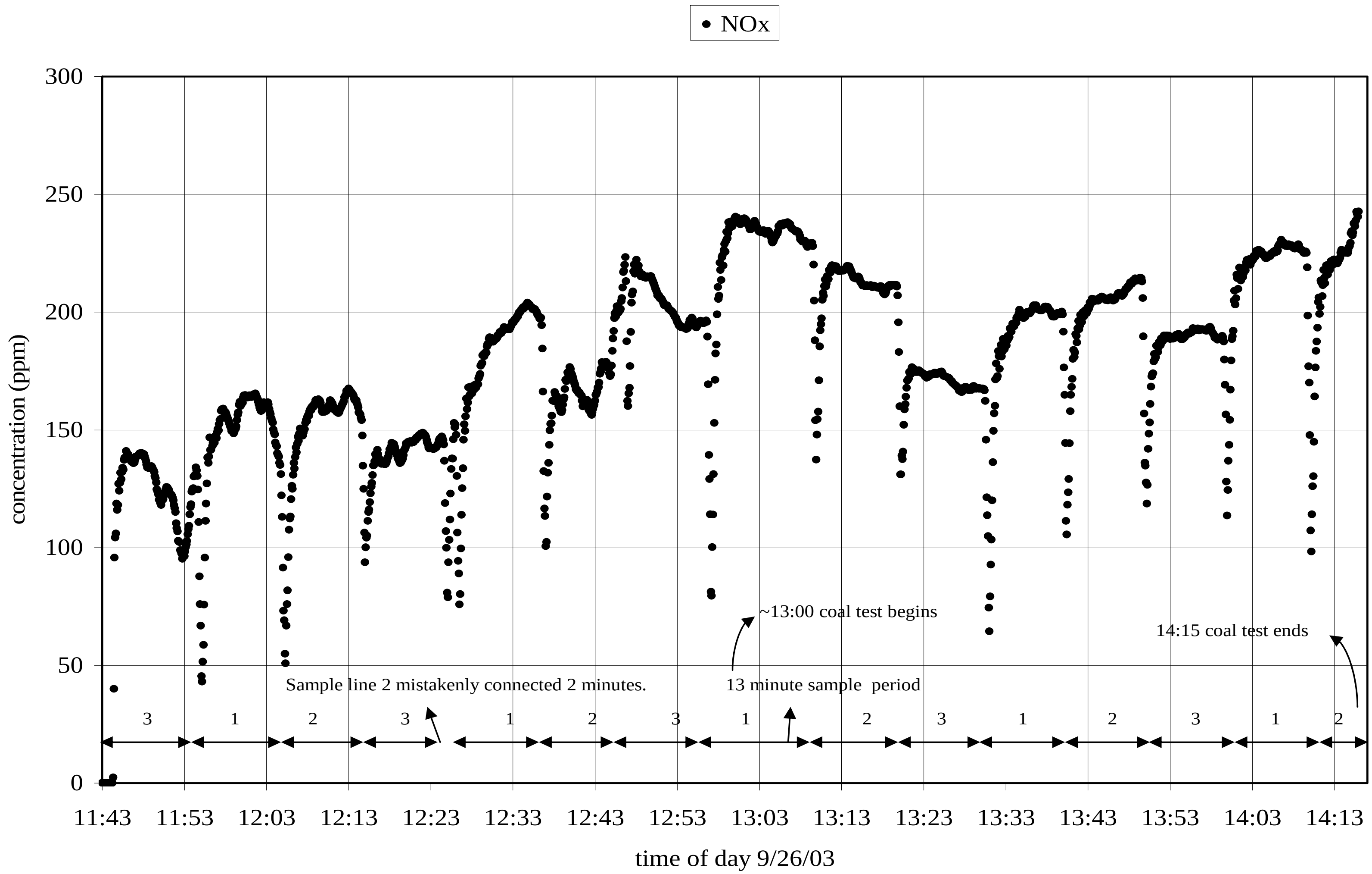


Figure C44. NOx concentrations recorded downstream of the air preheater in Boiler 3 firing coal on September 26, 2003, second sample period.

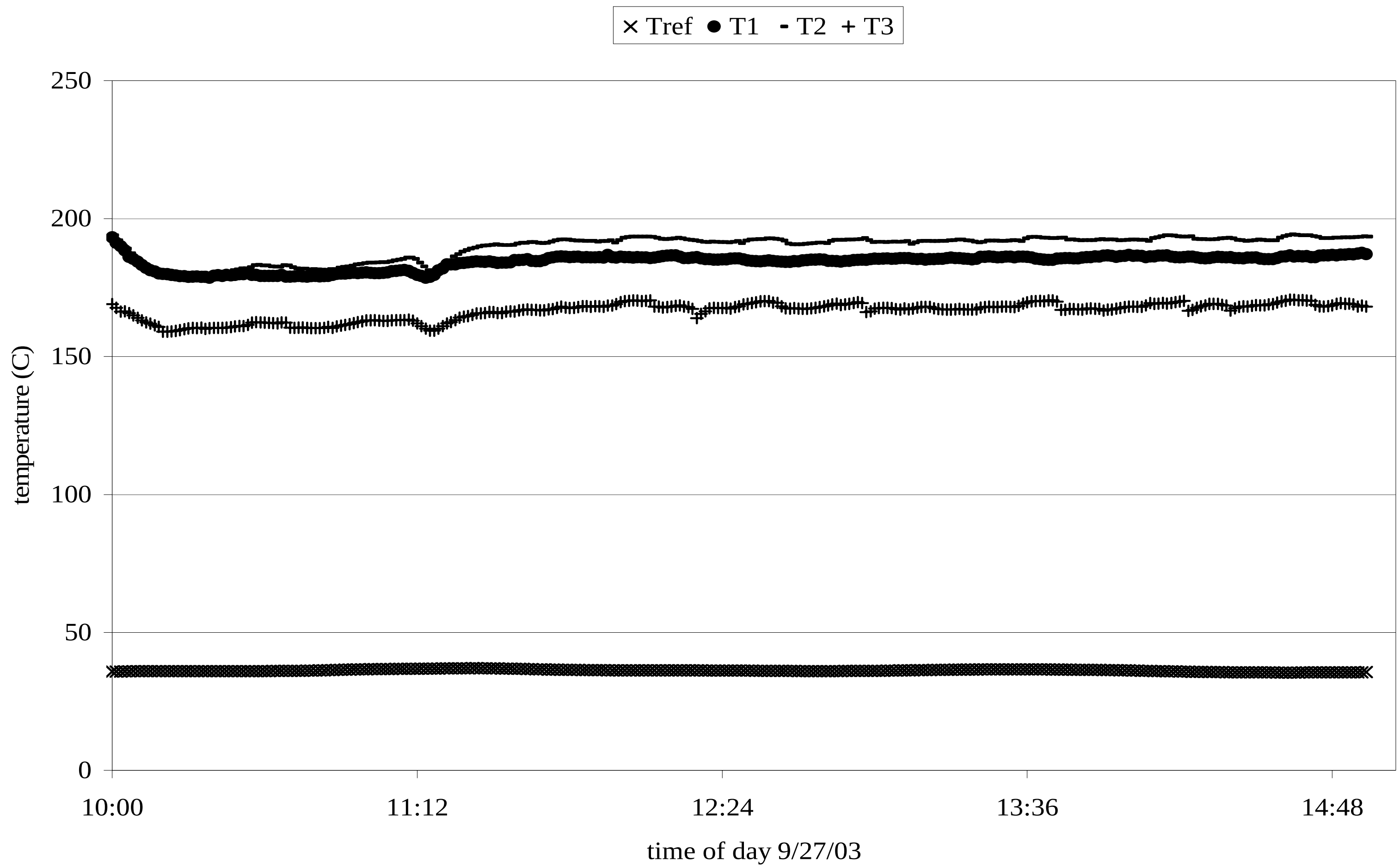


Figure C45. Temperatures recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

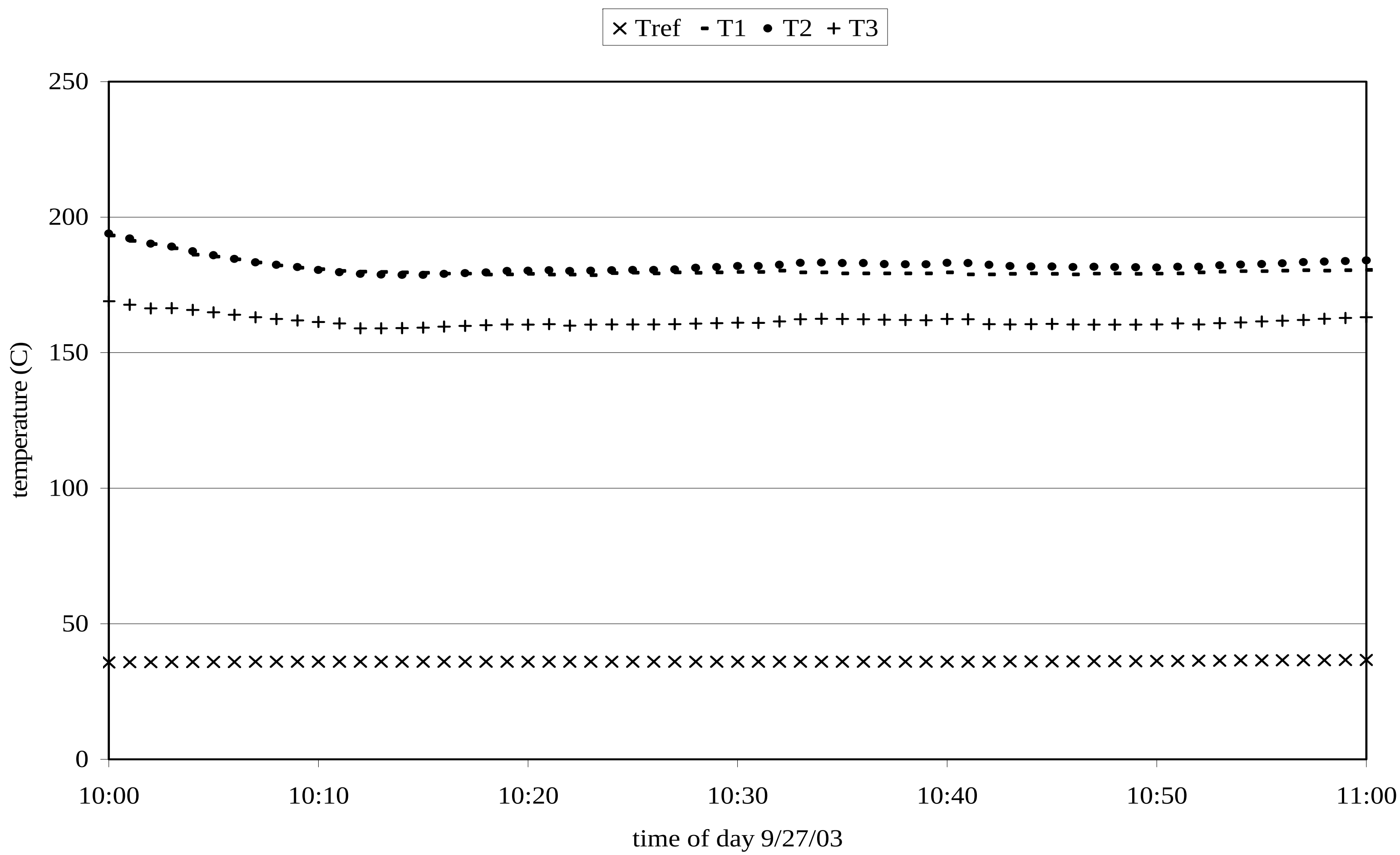


Figure C46. Temperatures recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, first sample period. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

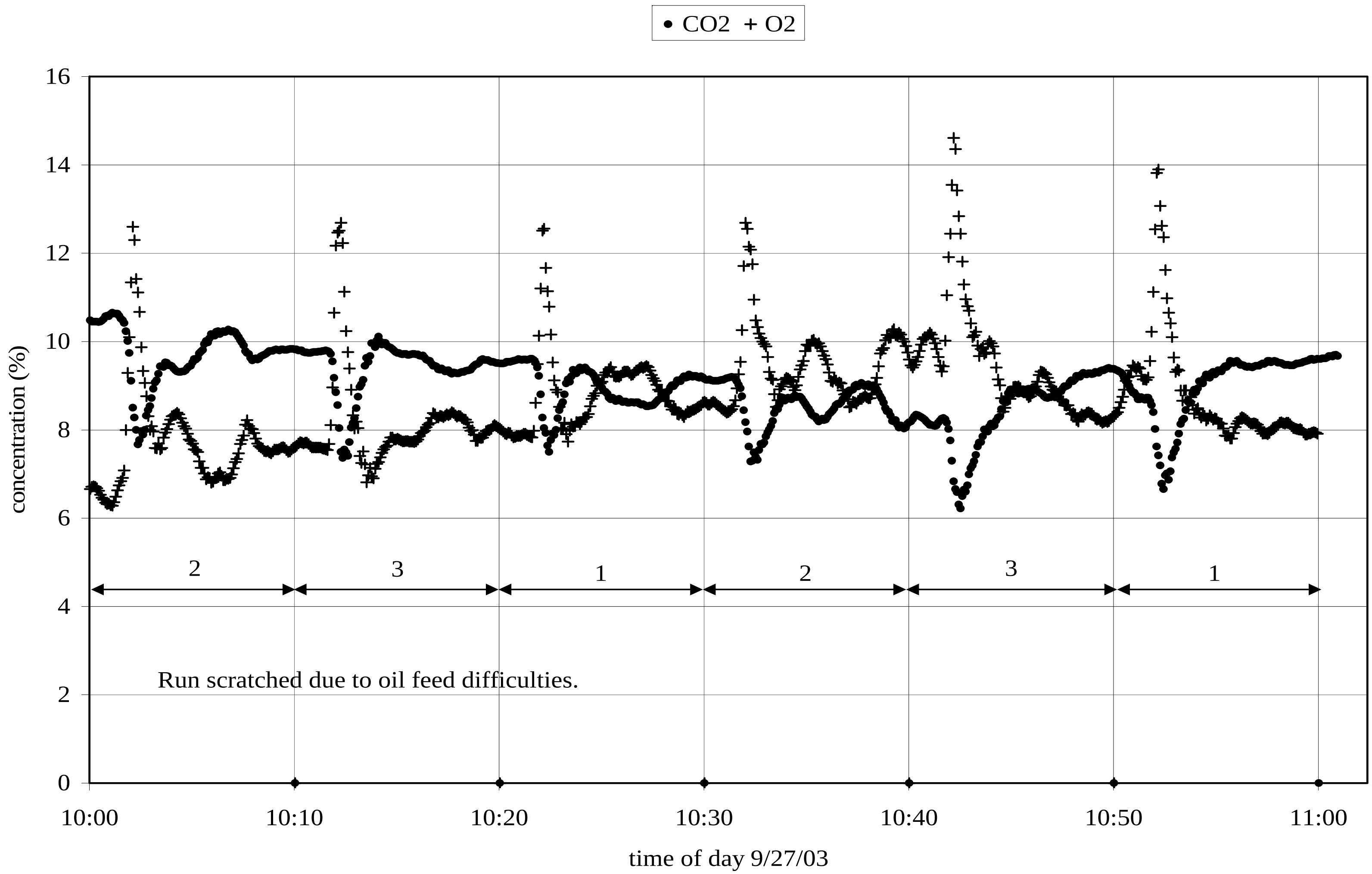


Figure C47. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, first sample period.

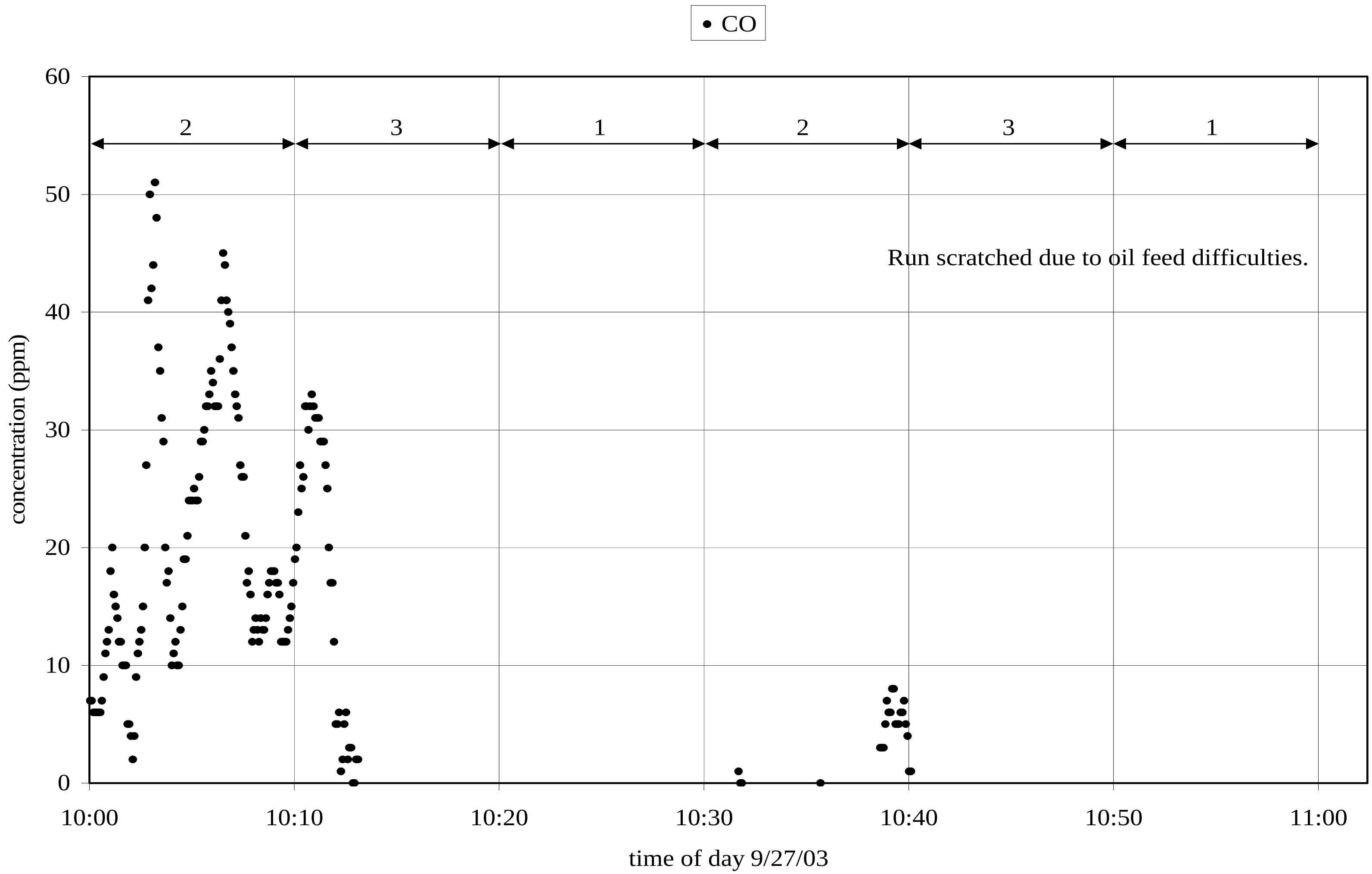


Figure C48. CO concentrations recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, first sample period.

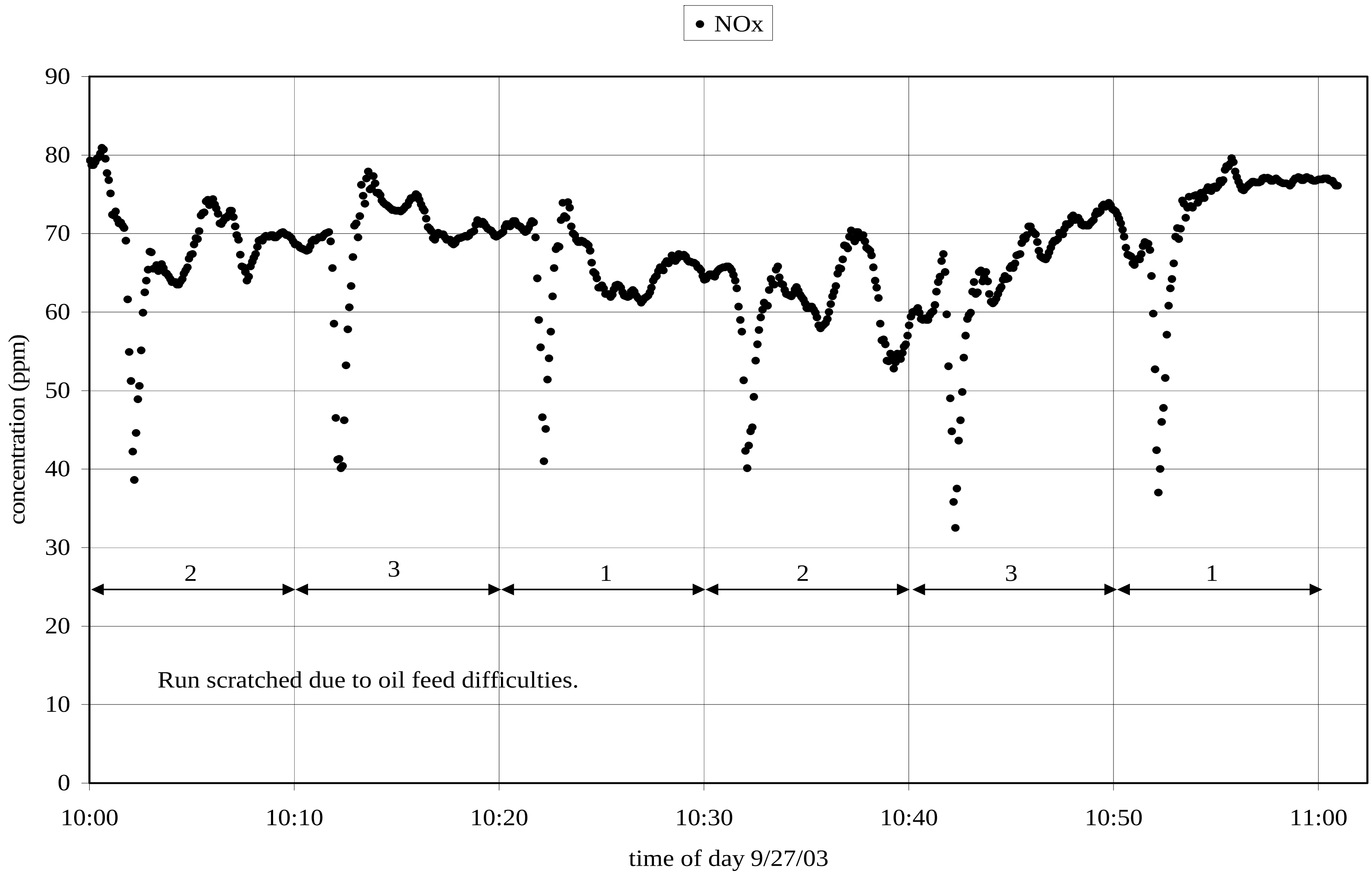


Figure C49. NOx concentrations recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, first sample period.

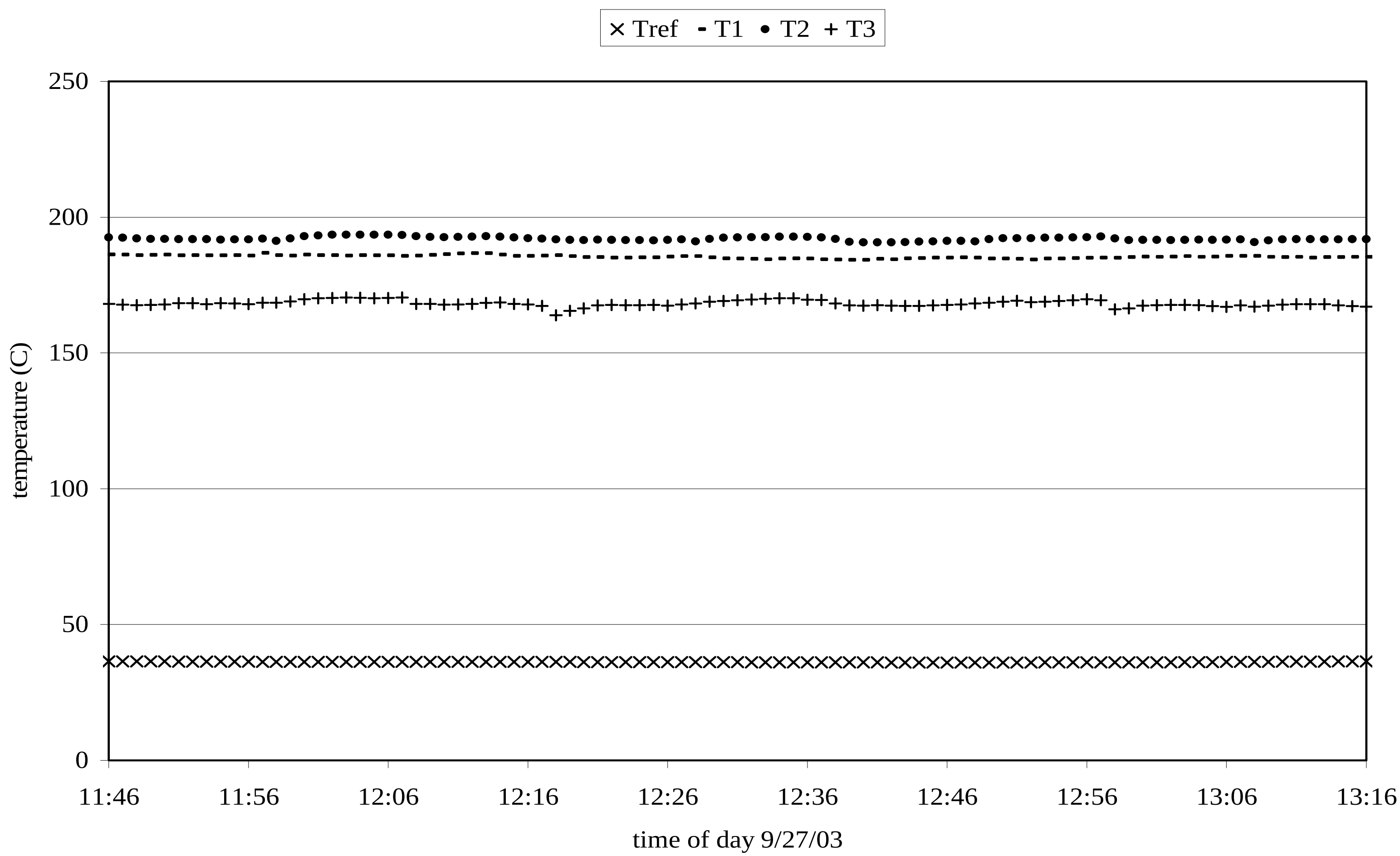


Figure C50. Temperatures recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, second sample period. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

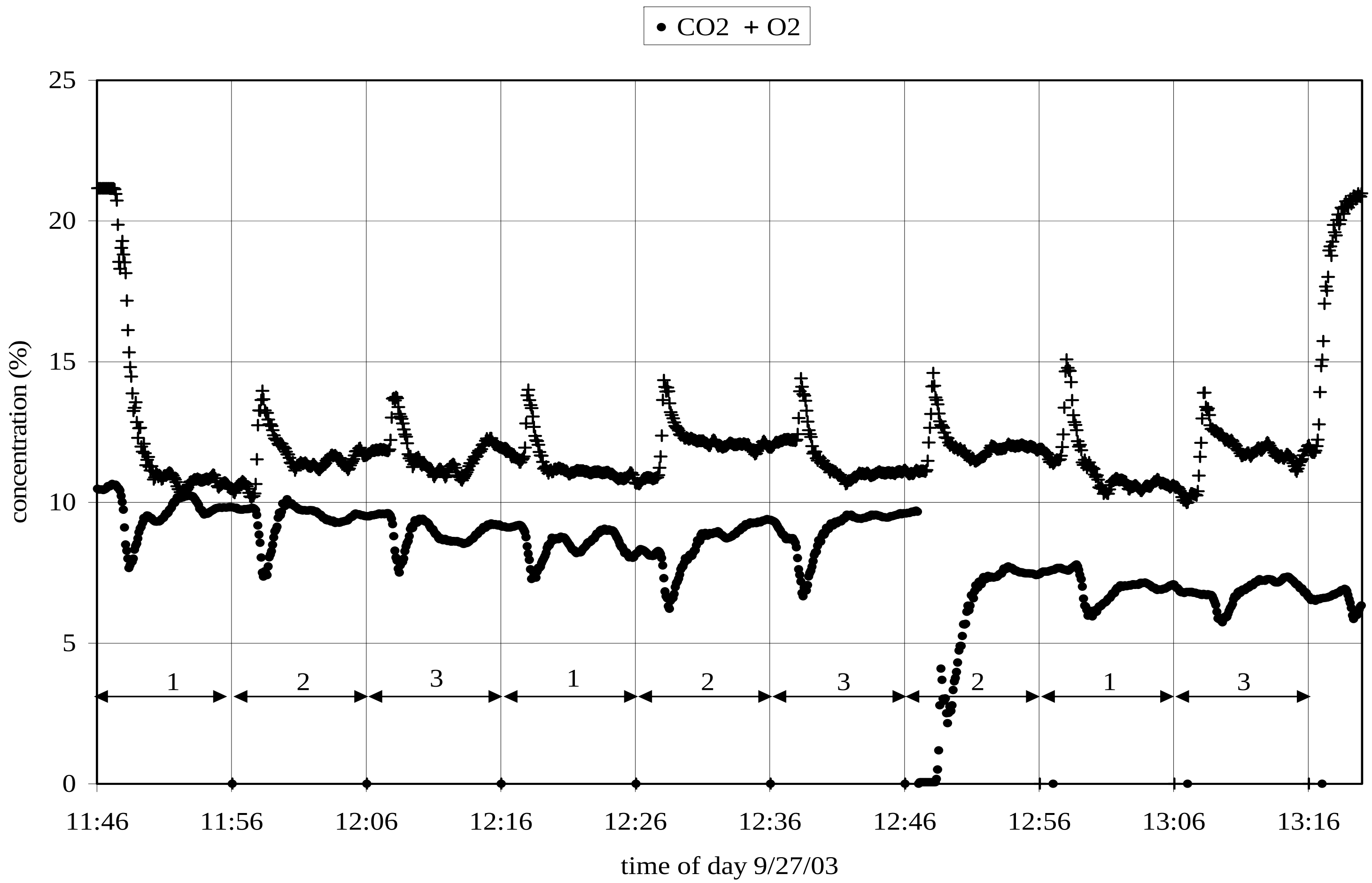


Figure C51. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, second sample period.

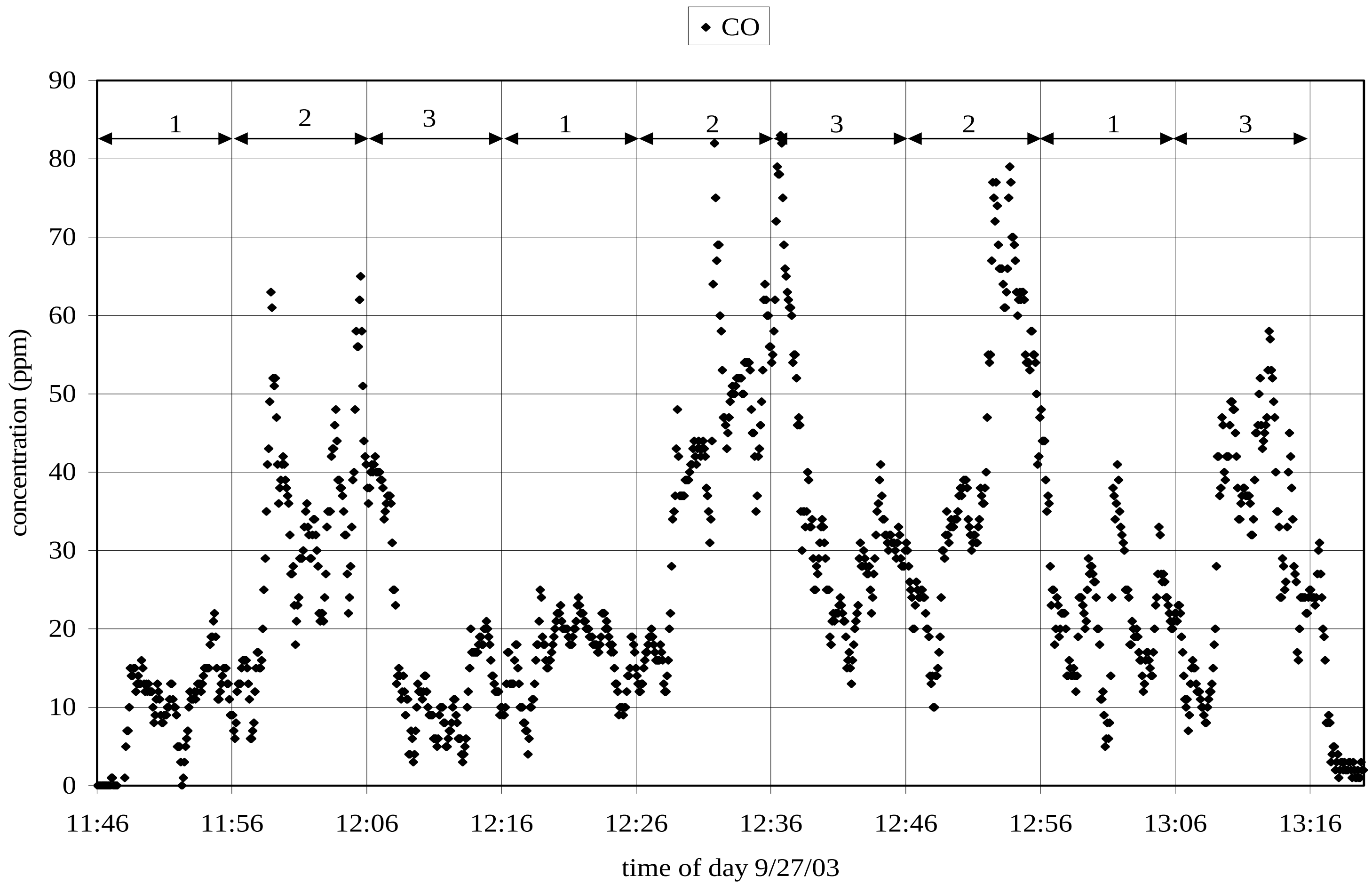


Figure C52. CO concentrations recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, second sample period.

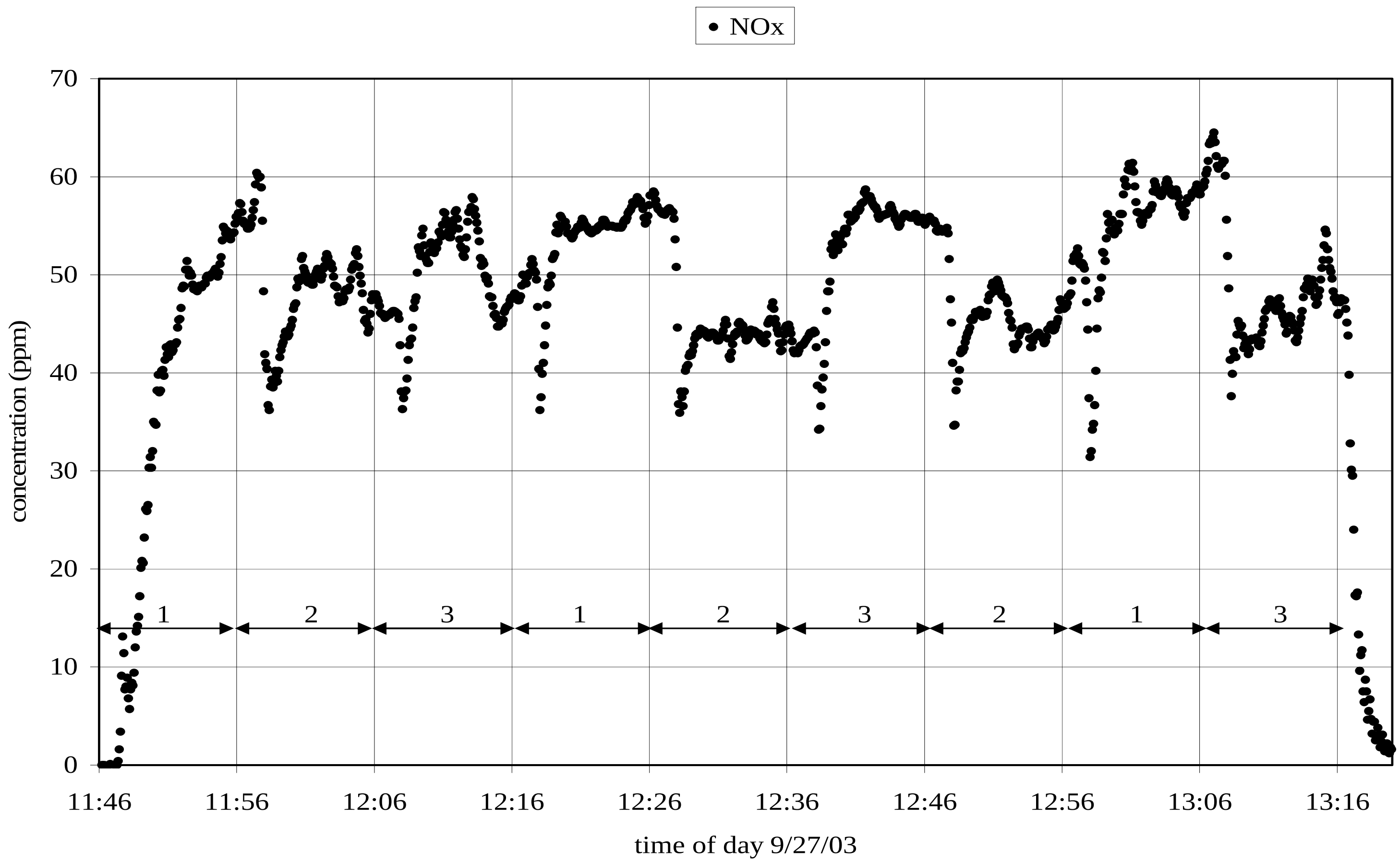


Figure C53. NOx concentrations recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, second sample period.

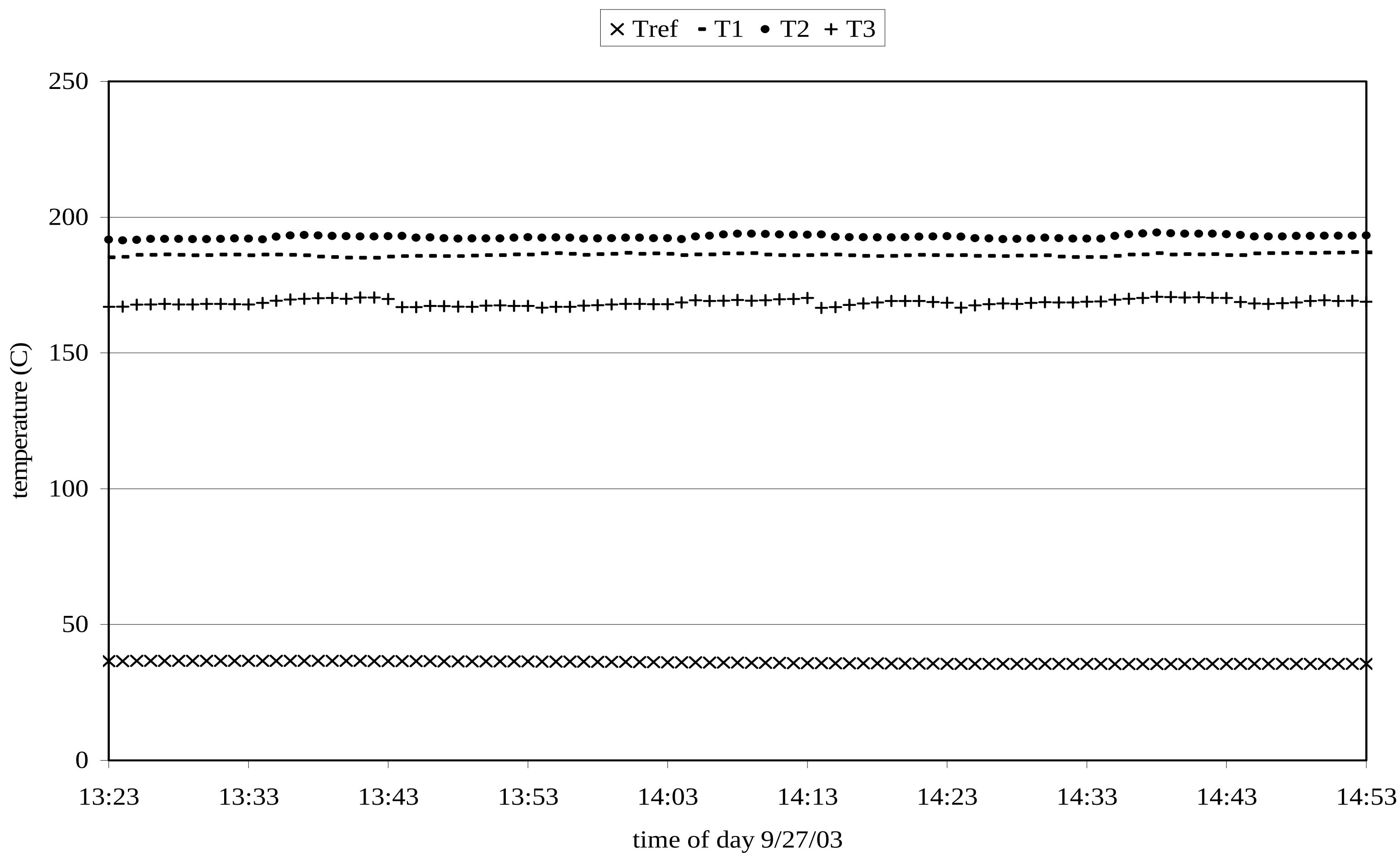


Figure C54. Temperatures recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, third sample period. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

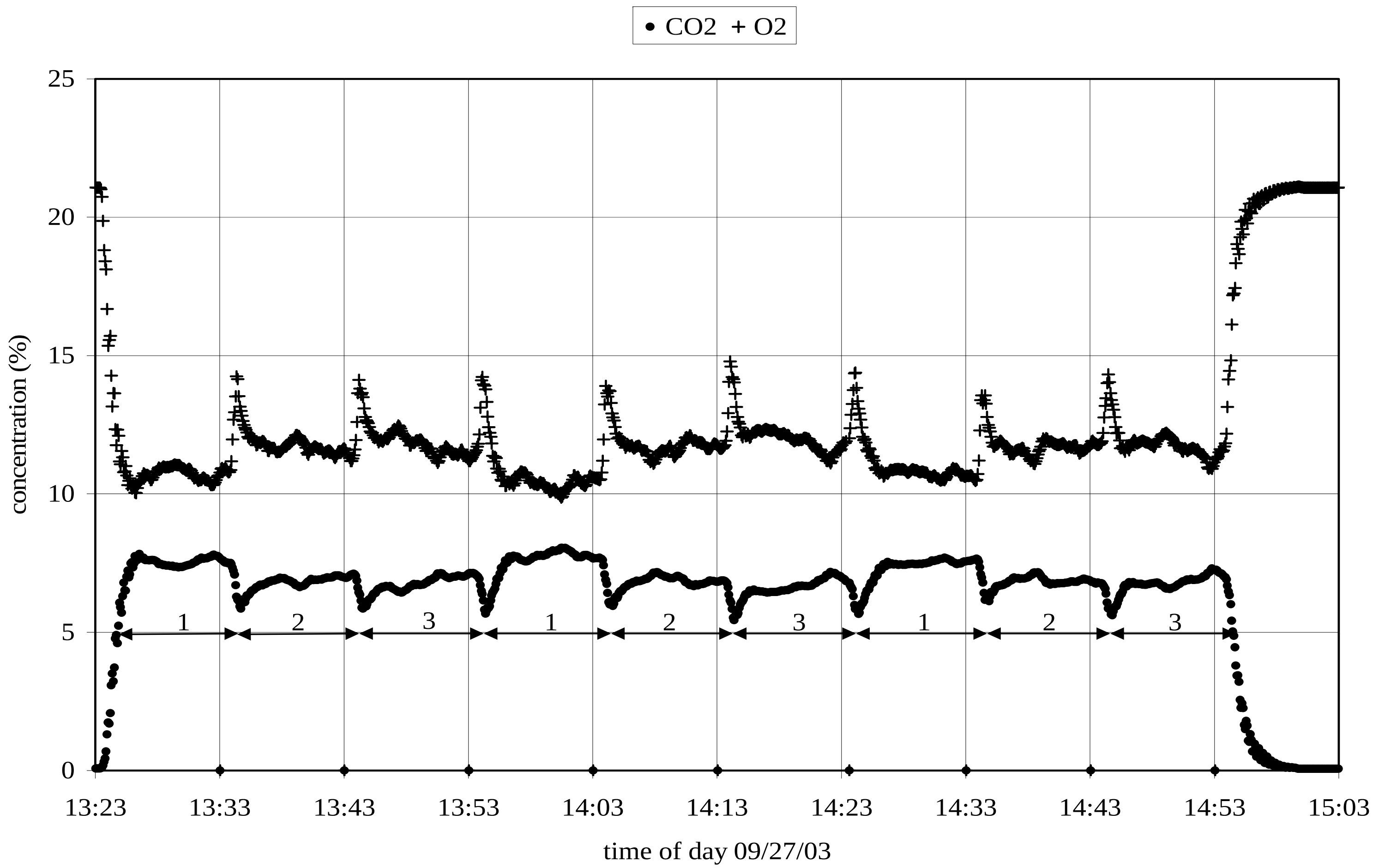


Figure C55. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, third sample period.

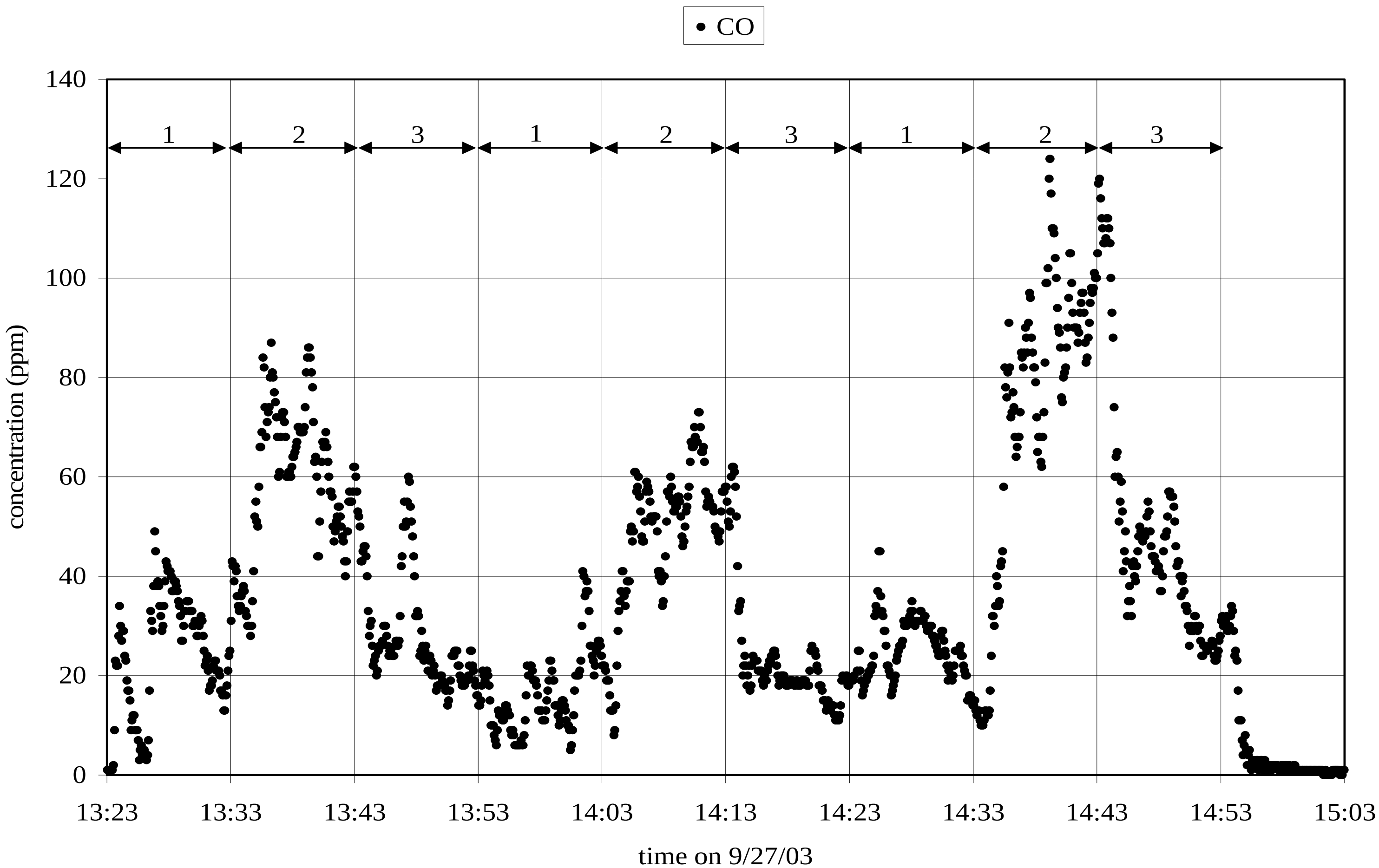


Figure C56. CO concentrations recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, third sample period.

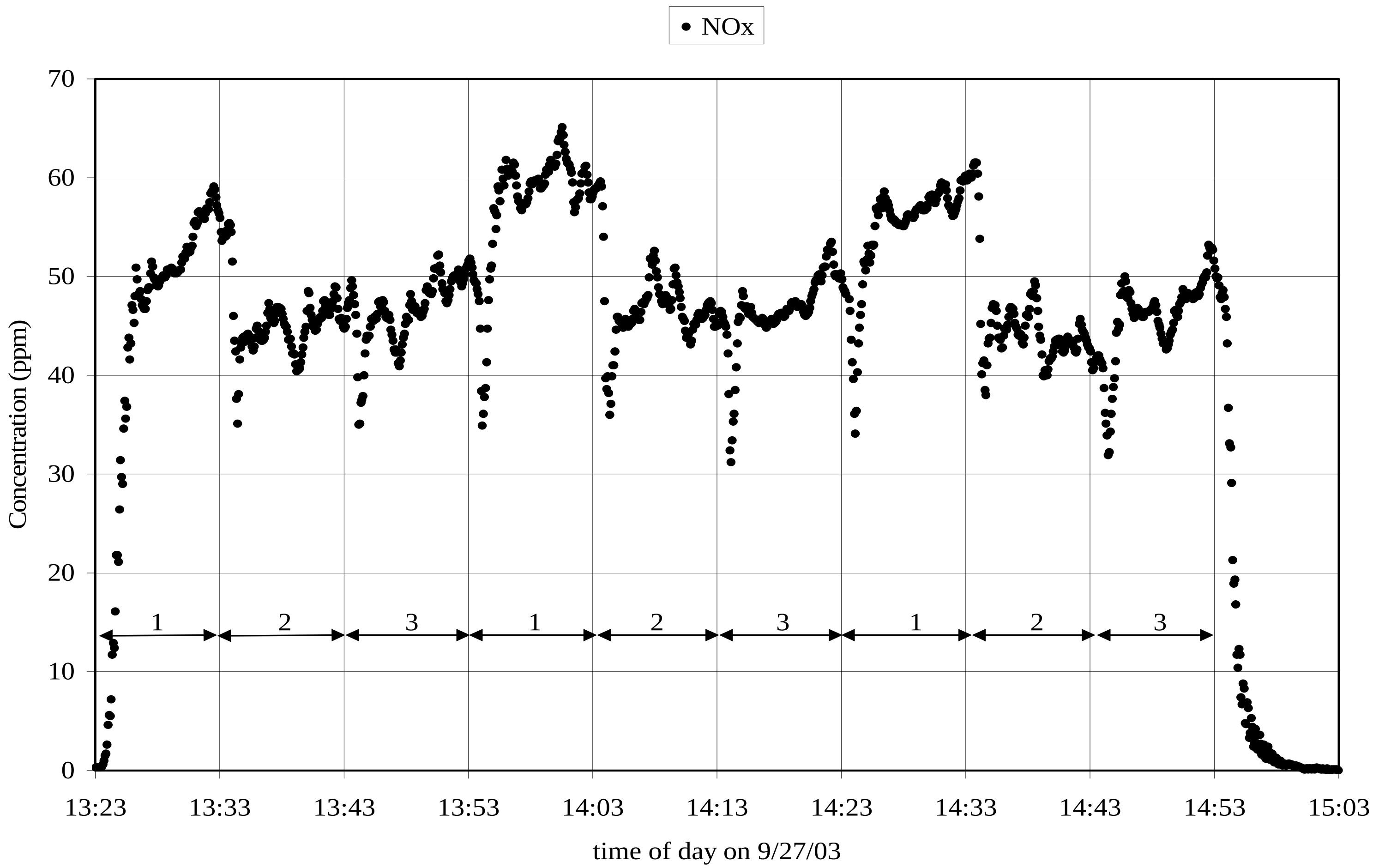


Figure C57. NOx concentrations recorded downstream of the air preheater in Boiler 3 firing oil on September 27, 2003, third sample period.

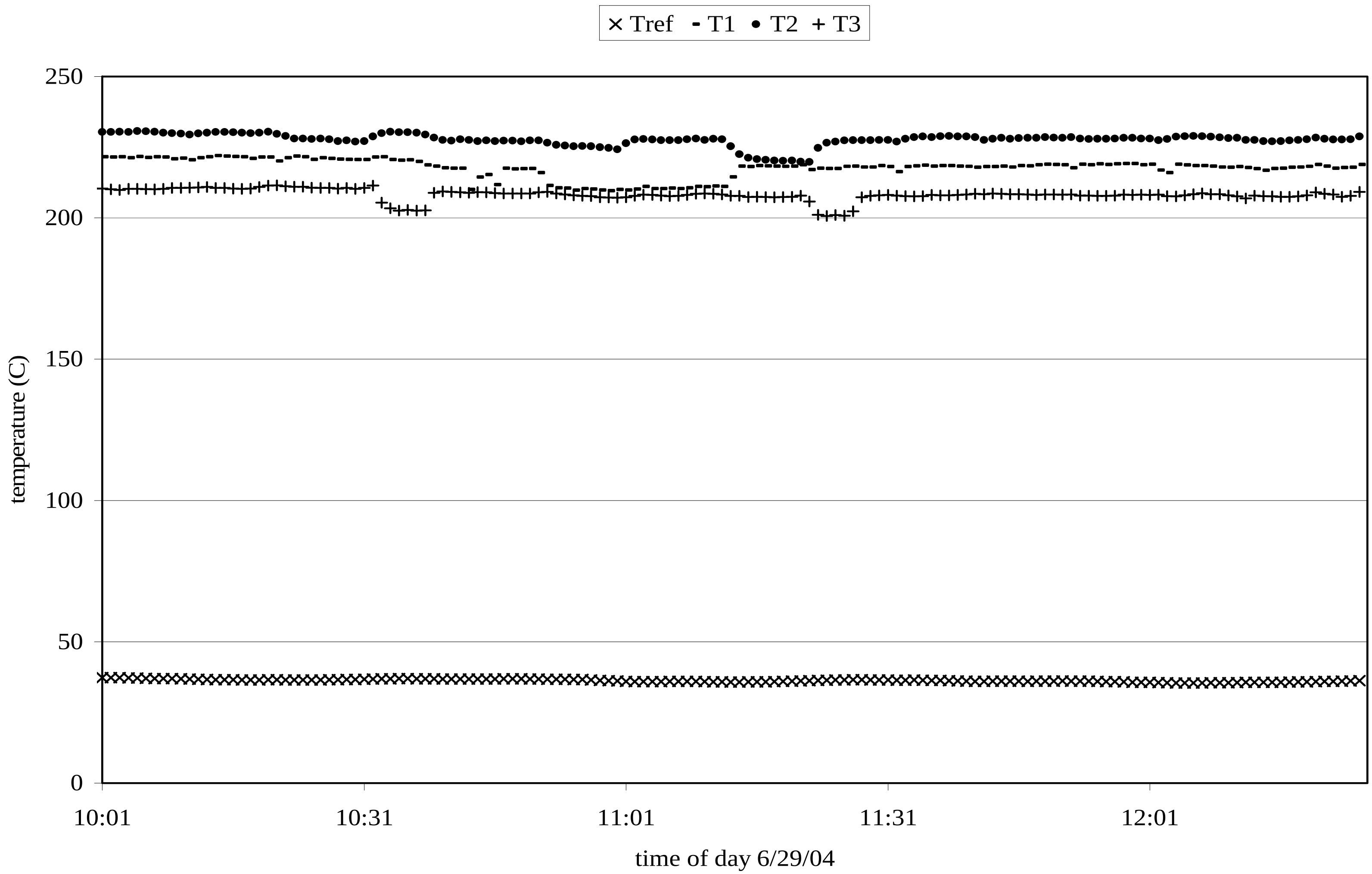


Figure C58. Temperatures recorded downstream of the air preheater in Boiler 2 firing coal on June 29, 2004. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

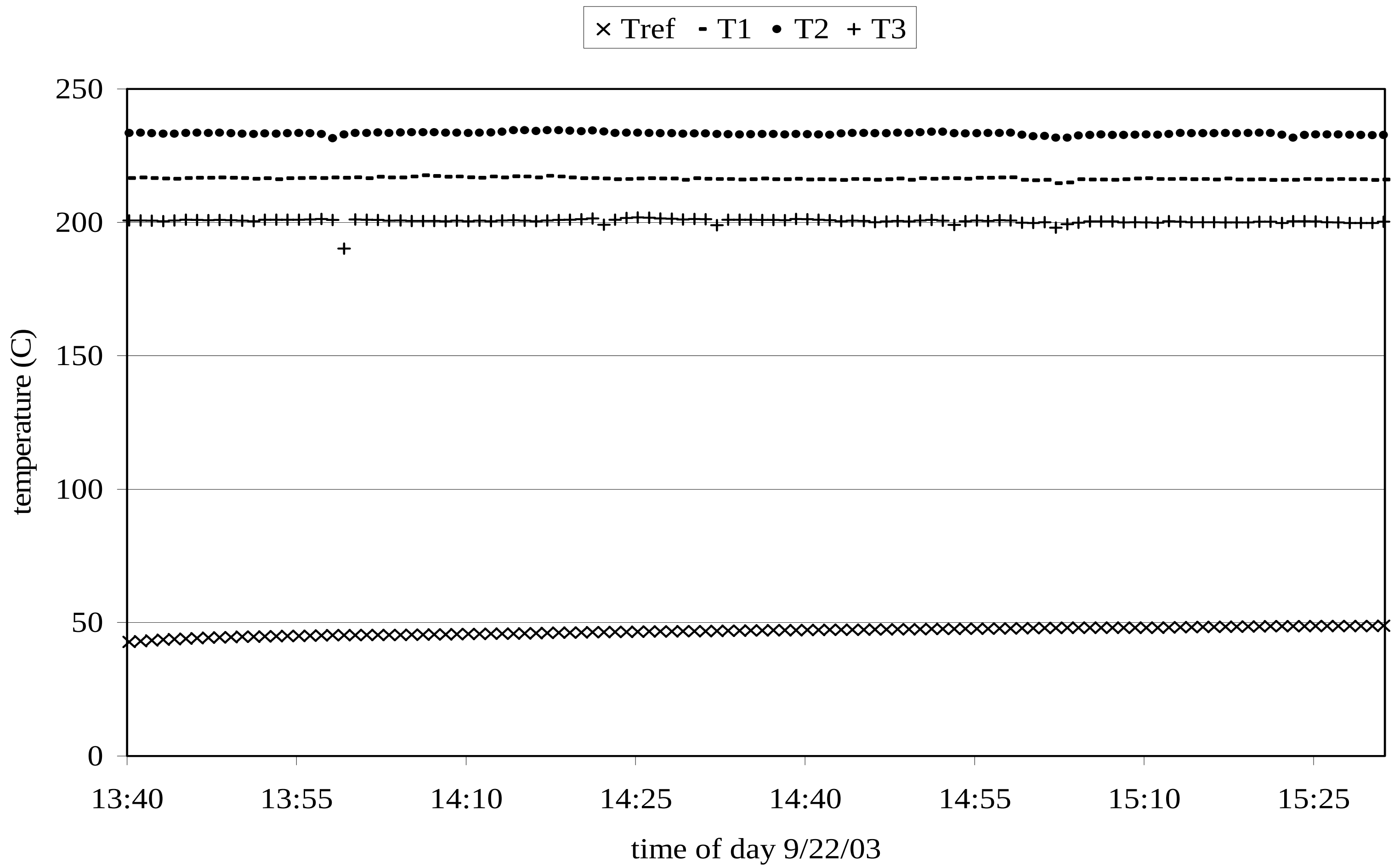


Figure C59. Temperatures recorded downstream of the air preheater in Boiler 2 firing coal on June 29, 2004, first sample period. Temperatures T1 though T3 are from Type K thermocouples located in the flue gas. Tref is an indicator of ambient temperature.

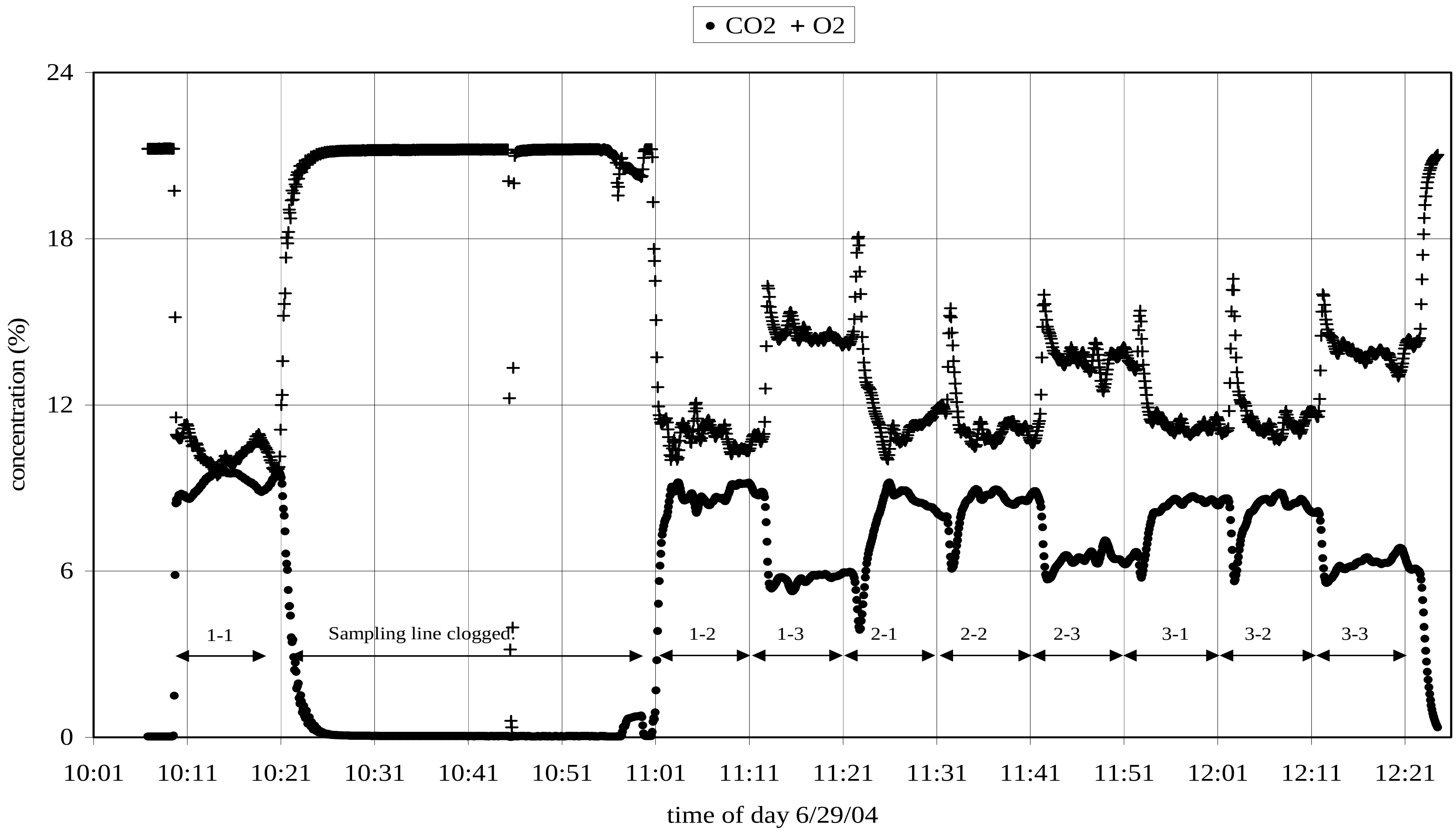


Figure C60. O_2 and CO_2 concentrations recorded downstream of the air preheater in Boiler 2 firing coal on June 29, 2004, first sample period.

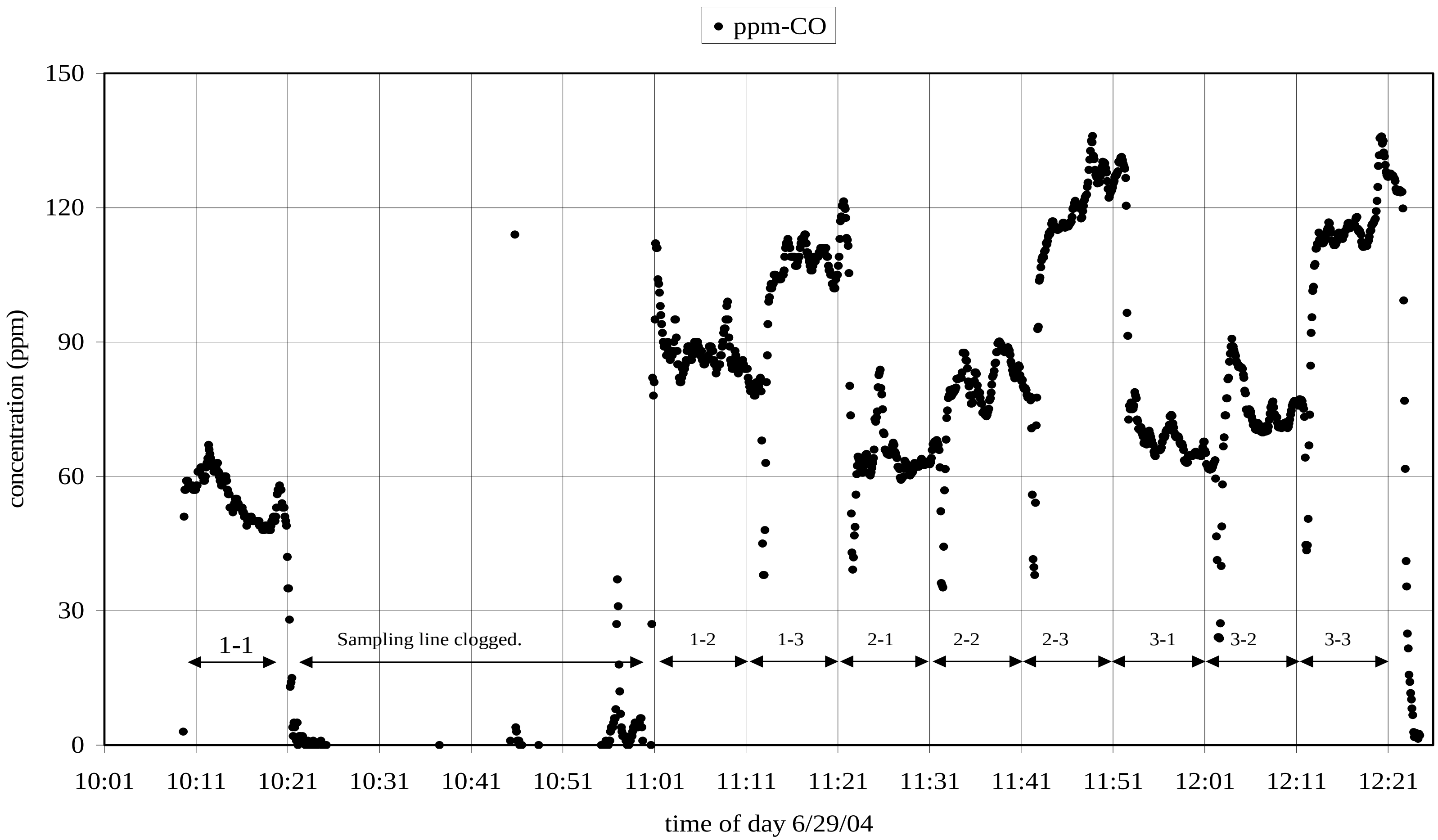


Figure C61. CO concentrations recorded downstream of the air preheater in Boiler 2 firing coal on June 29, 2004, first sample period.

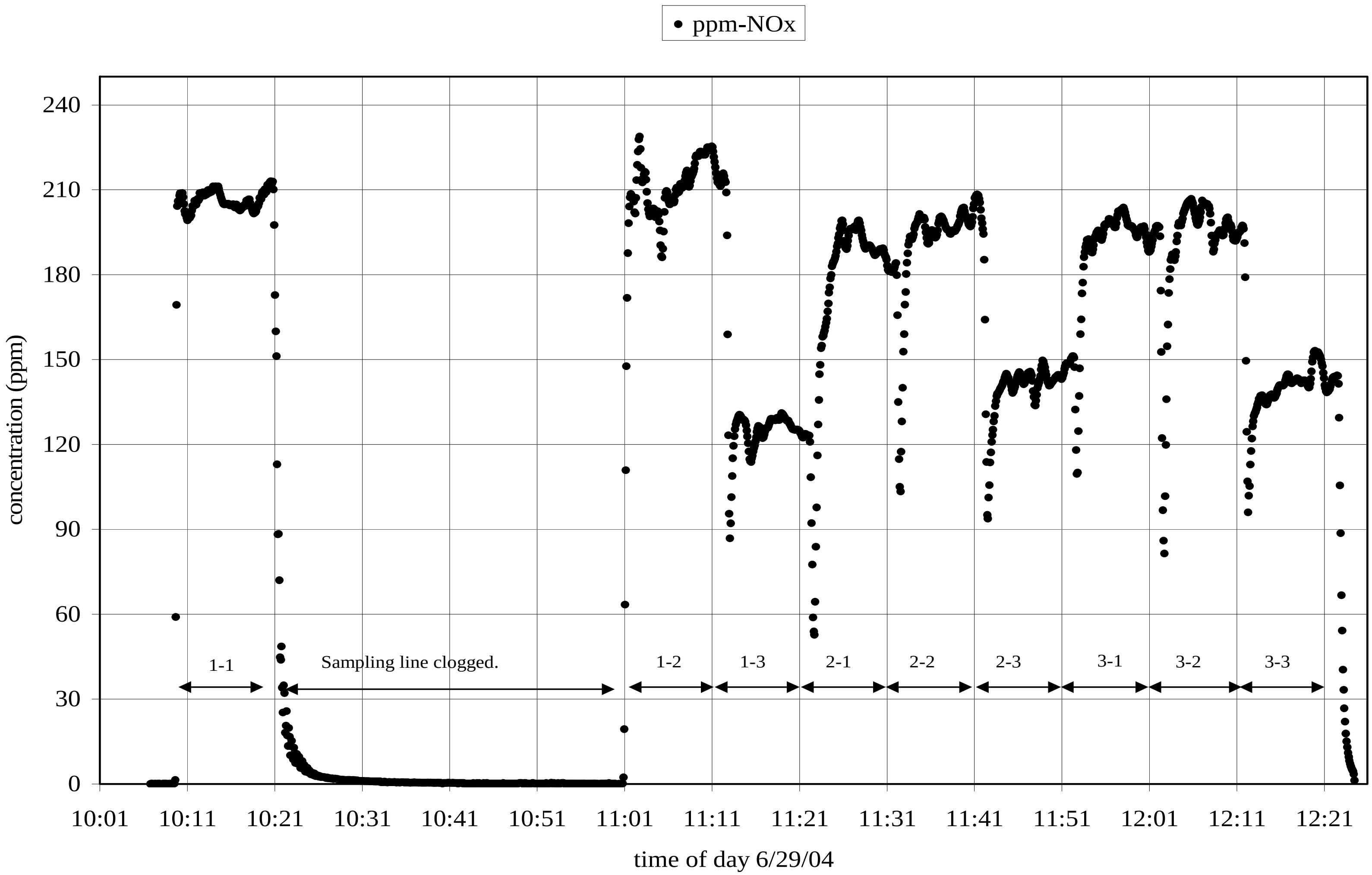


Figure C62. NOx concentrations recorded downstream of the air preheater in Boiler 2 firing coal on June 29, 2004, first sample period.

Appendix D

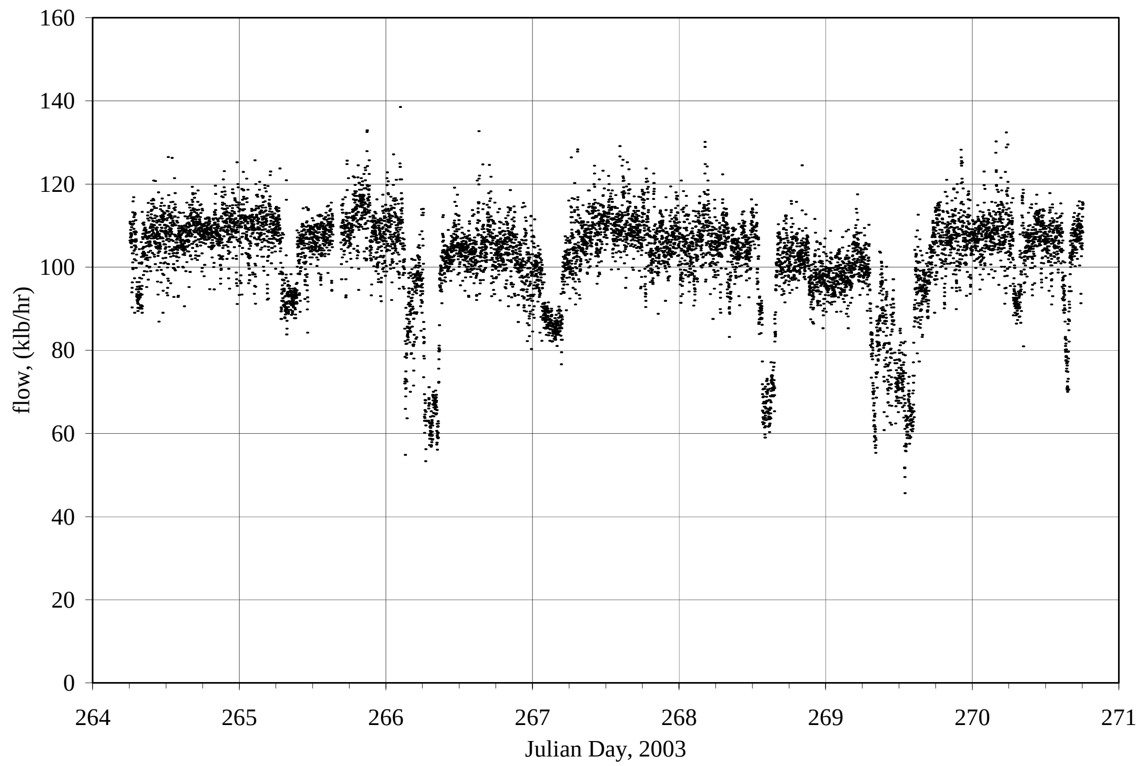


Figure D1. Steam flow rate, Boiler 1. Julian Day 264 = September 21, 2003.

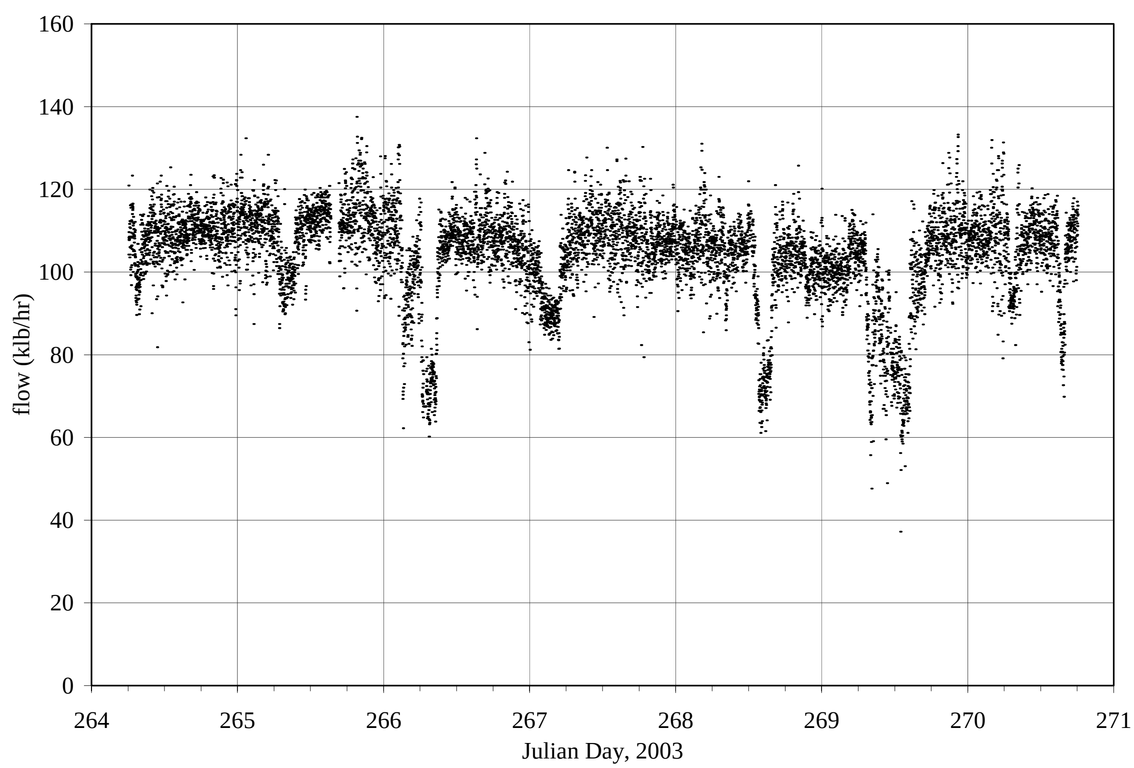


Figure D2. Feed water flow rate, Boiler 1. Julian Day 264 = September 21, 2003.

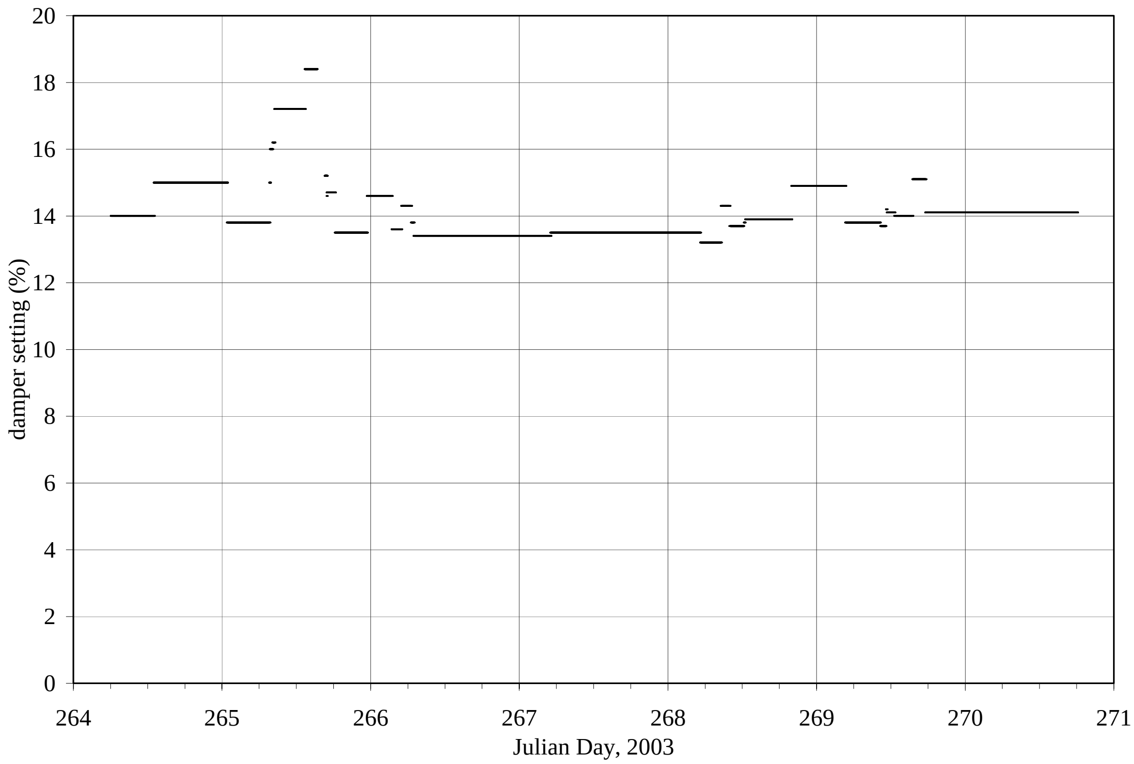


Figure D3. Right grate air flow rate, Boiler 1. Julian Day 264 = September 21, 2003.

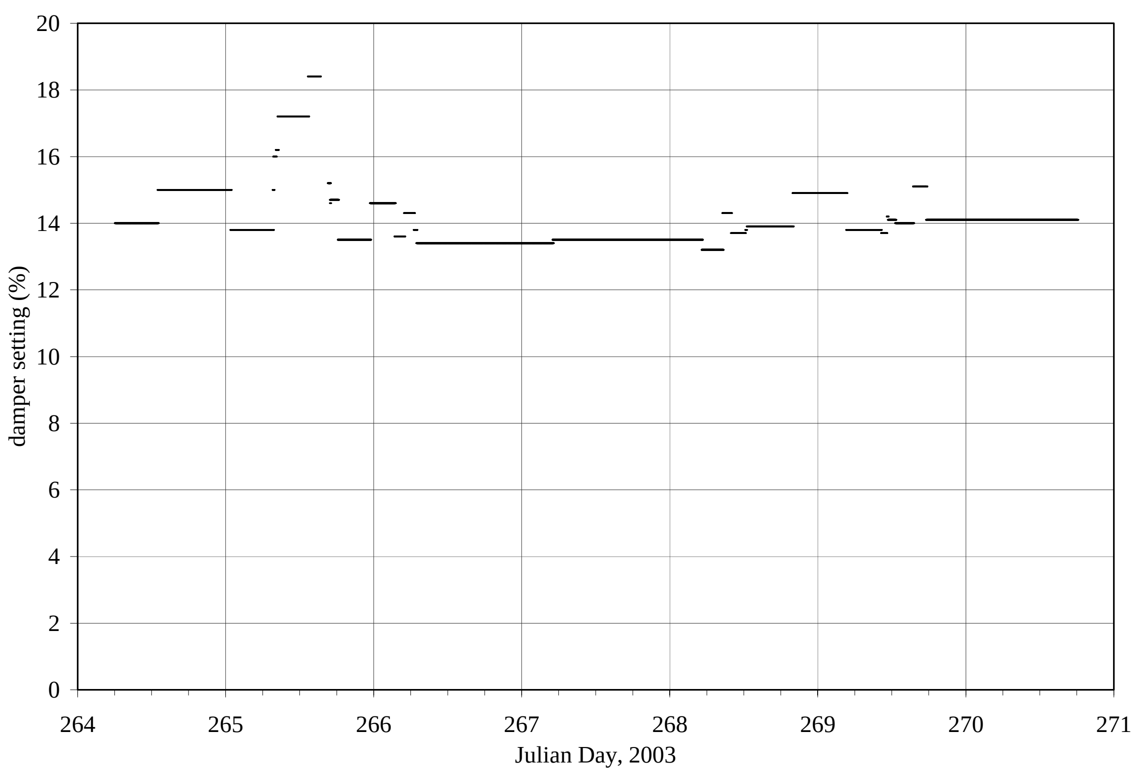


Figure D4. Left grate air flow rate, Boiler 1. Julian Day 264 = September 21, 2003.

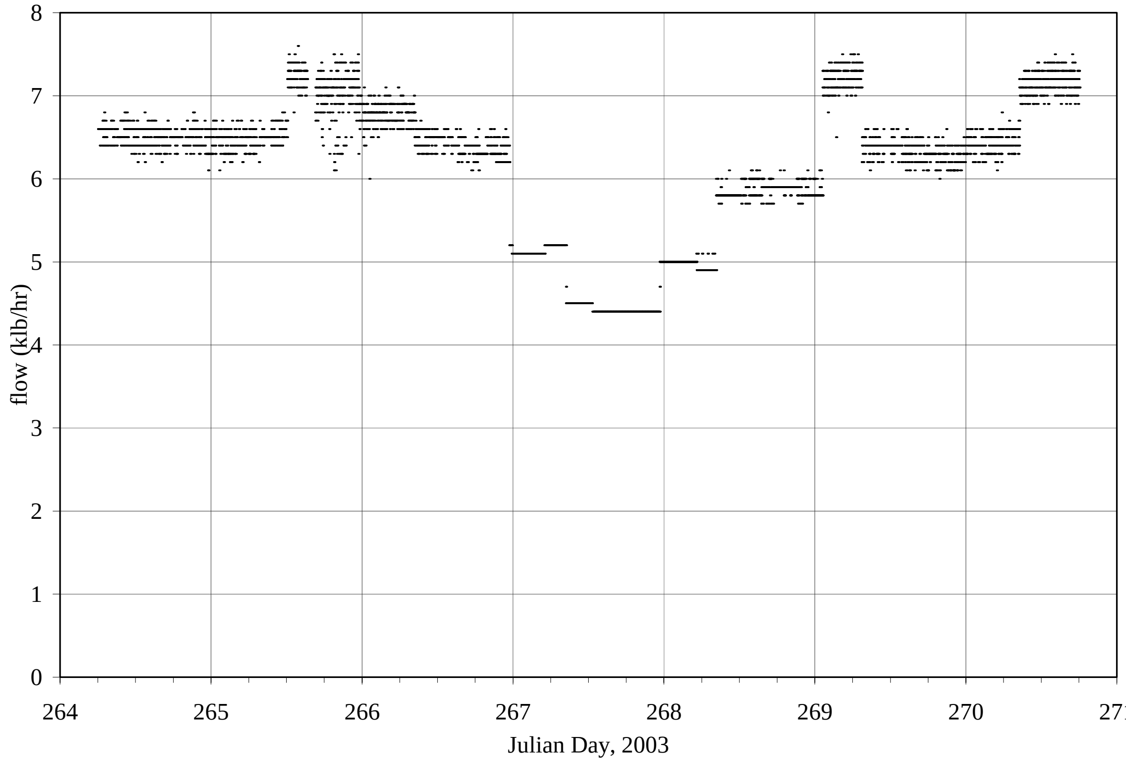


Figure D5. Continuous blowdown flow rate, Boiler 1. Julian Day 264 = September 21, 2003.

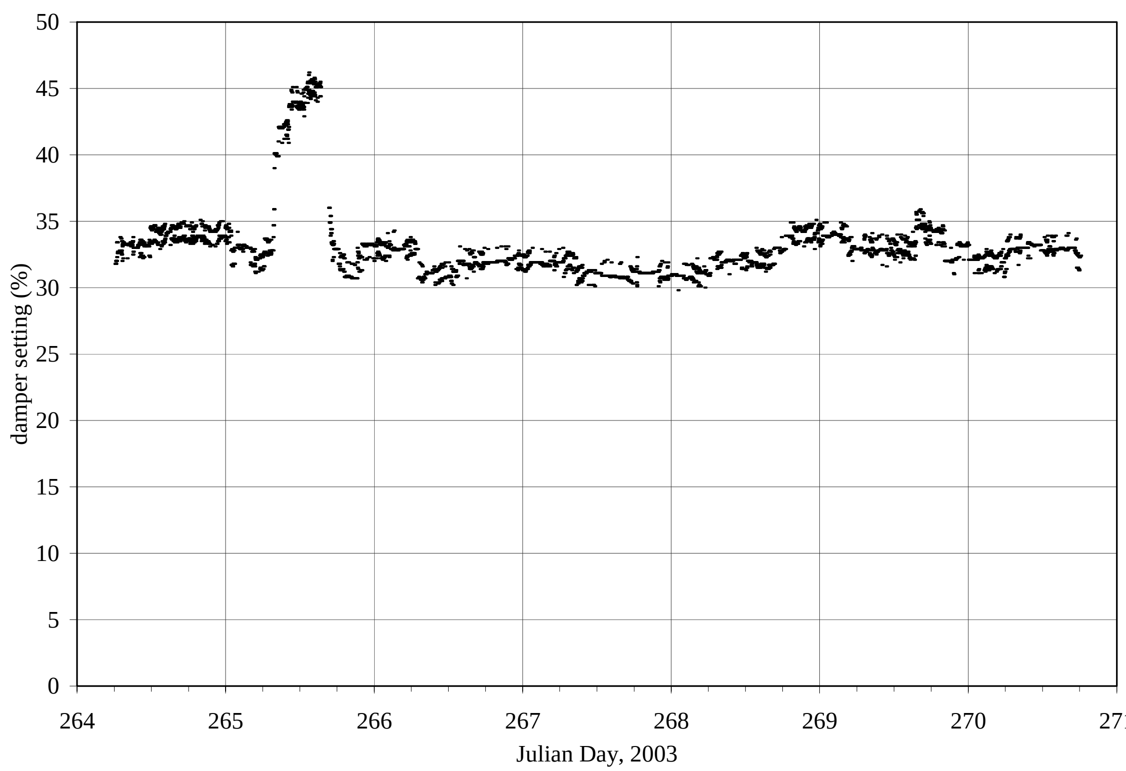


Figure D6. Grate air flow rate, Boiler 1. Julian Day 264 = September 21, 2003.

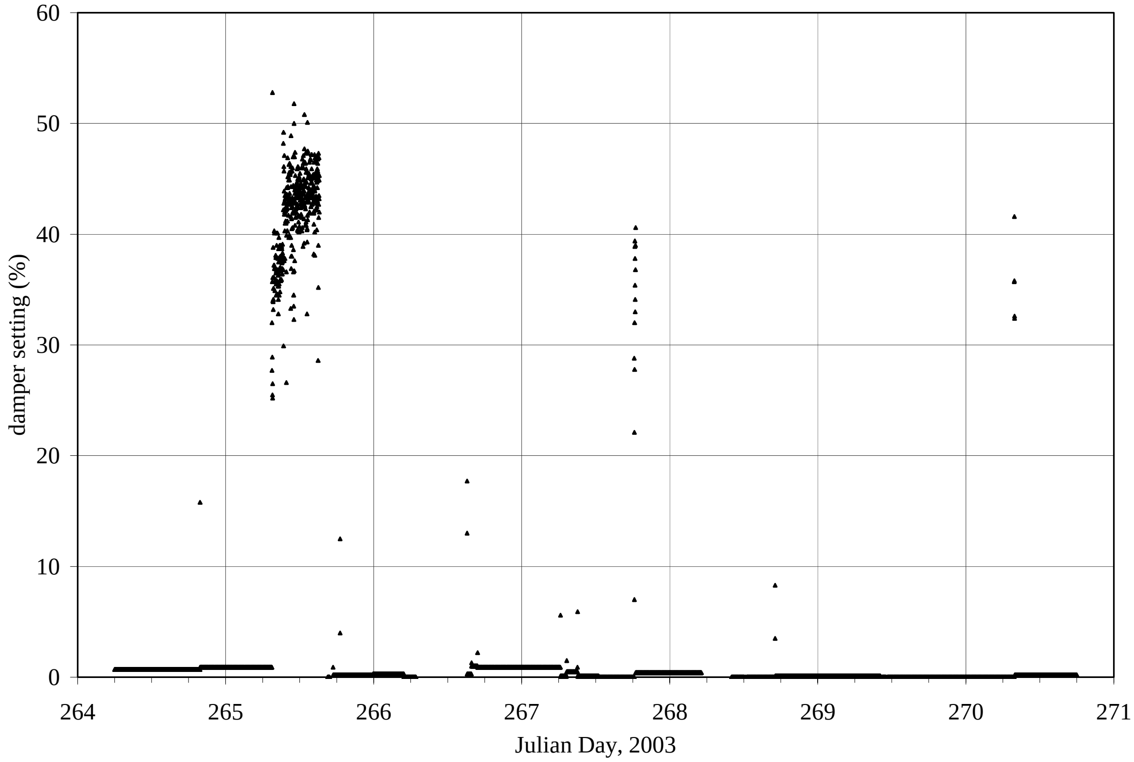


Figure D7. Coal flow rate, Boiler 1. Julian Day 264 = September 21, 2003.

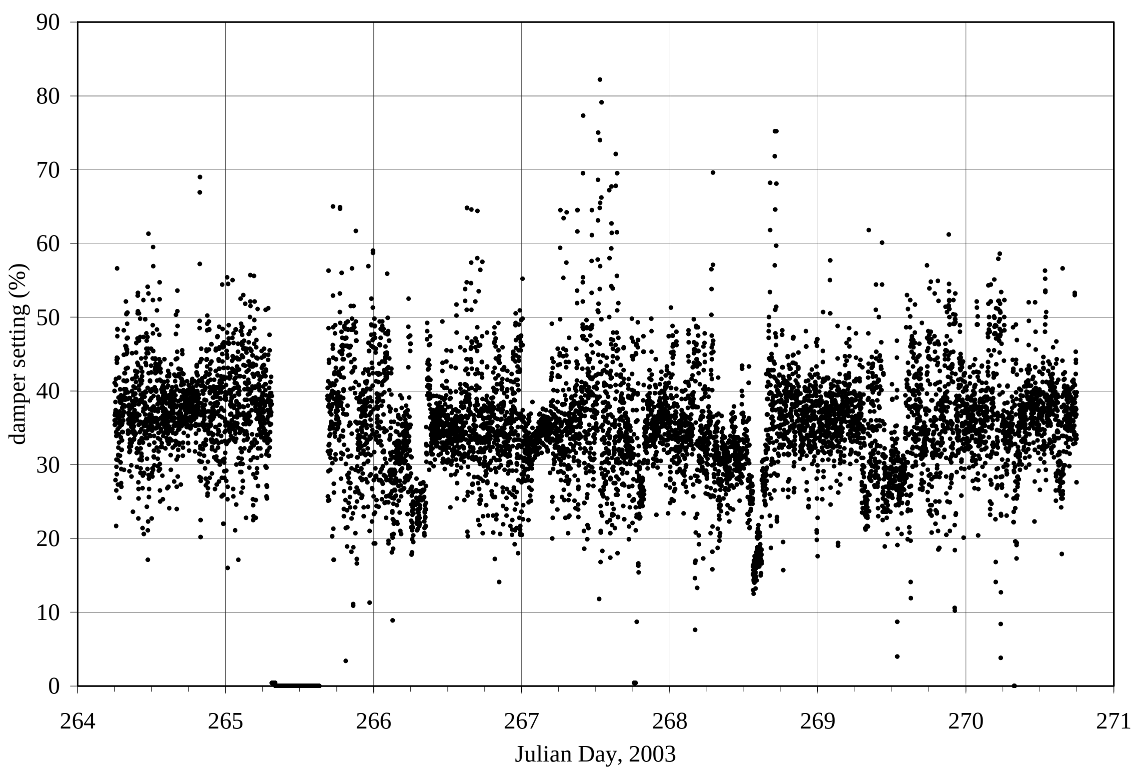


Figure D8. Bagasse feed rate, Boiler 1. Julian Day 264 = September 21, 2003.

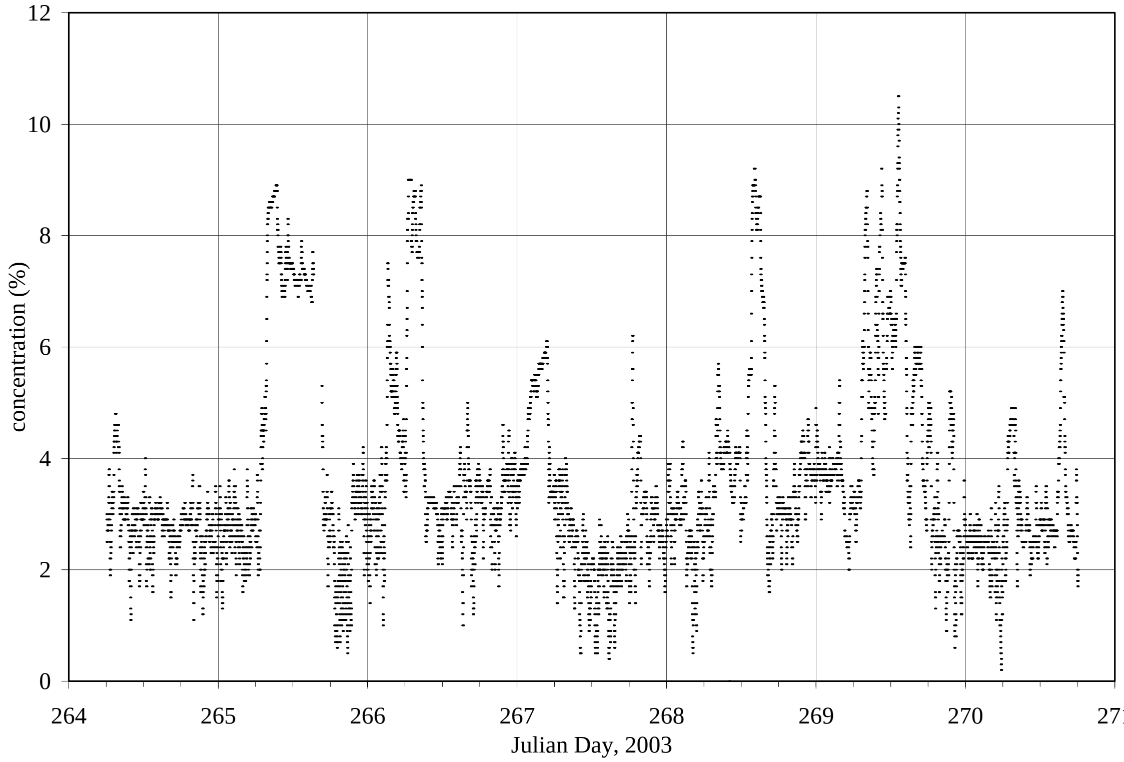


Figure D9. O_2 concentration, Boiler 1. Julian Day 264 = September 21, 2003.

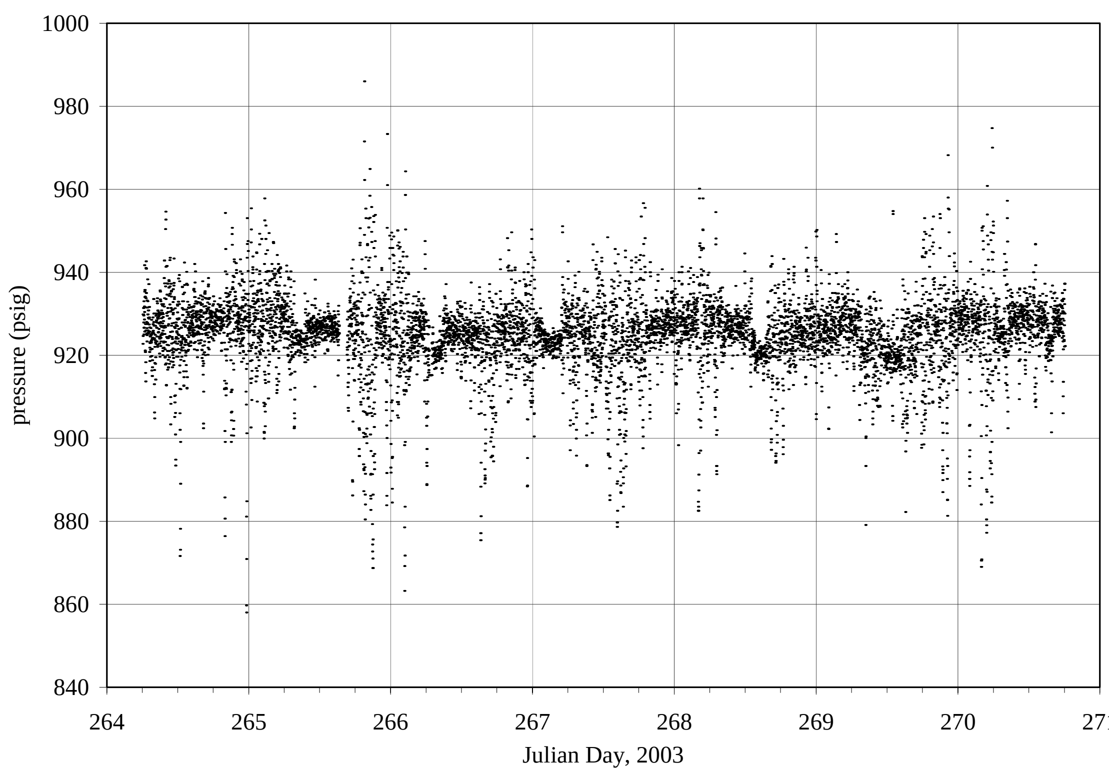


Figure D10. Drum pressure, Boiler 1. Julian Day 264 = September 21, 2003.

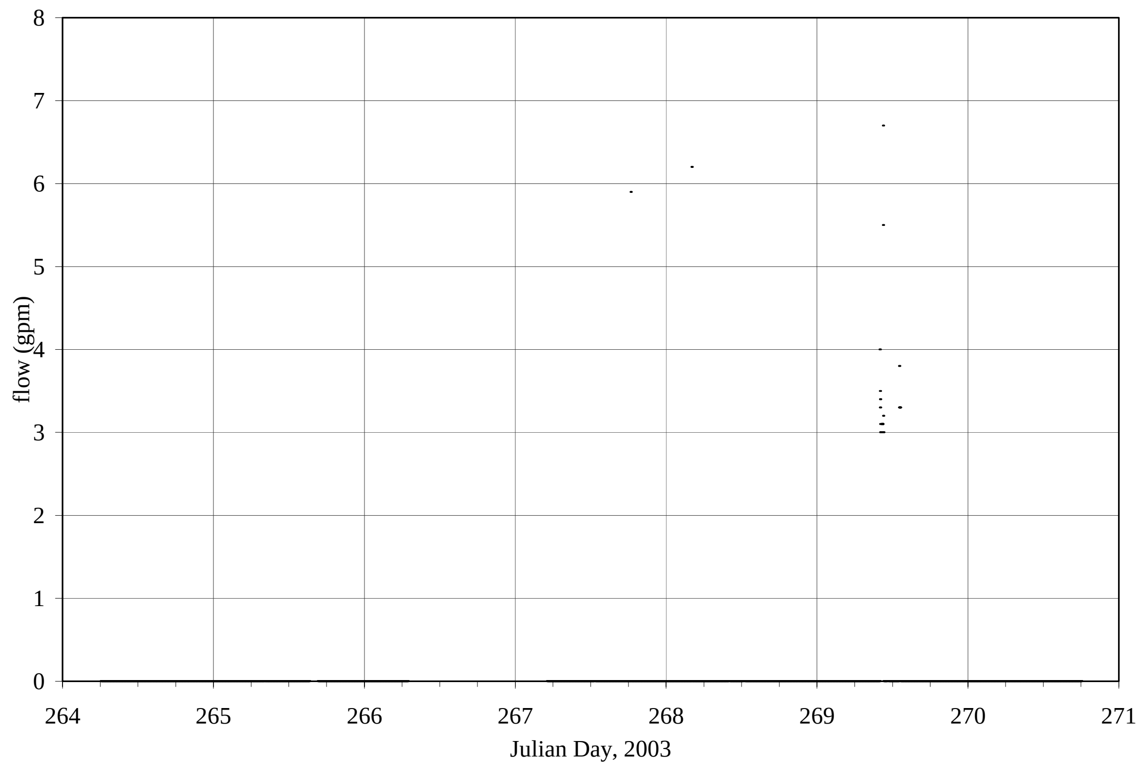


Figure D11. Fuel Oil flow rate, Boiler 1. Julian Day 264 = September 21, 2003.

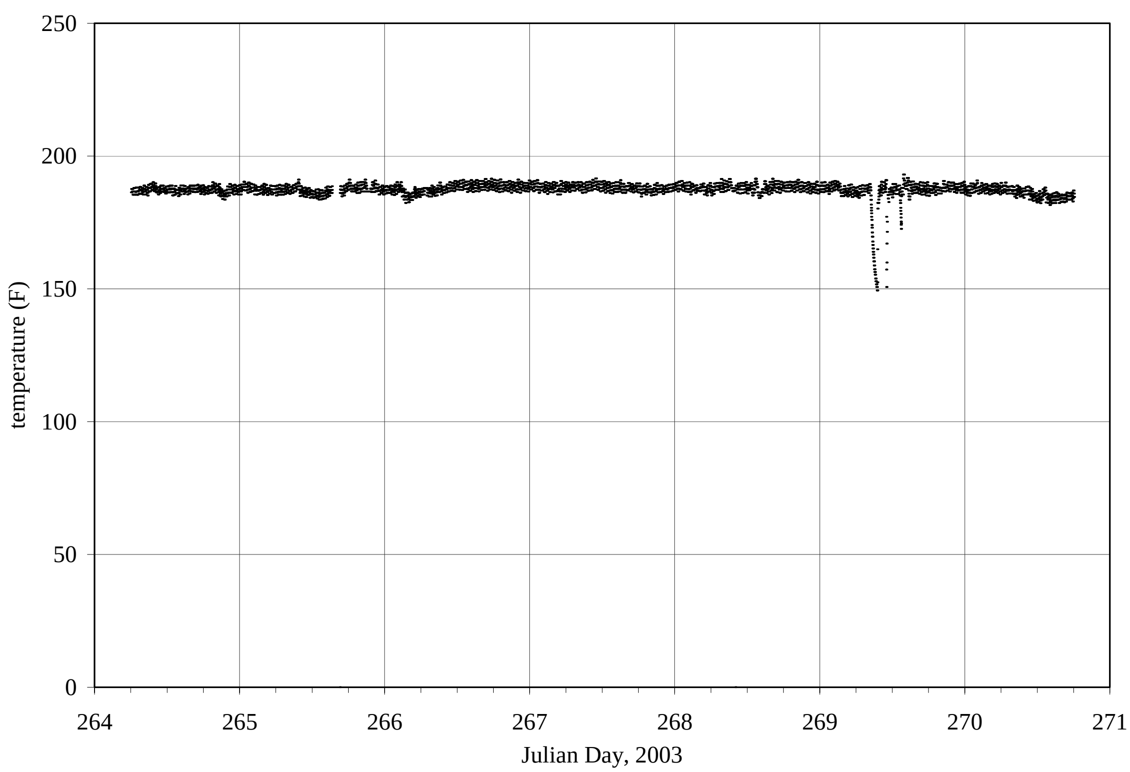


Figure D12. Fuel Oil temperature, Boiler 1. Julian Day 264 = September 21, 2003.

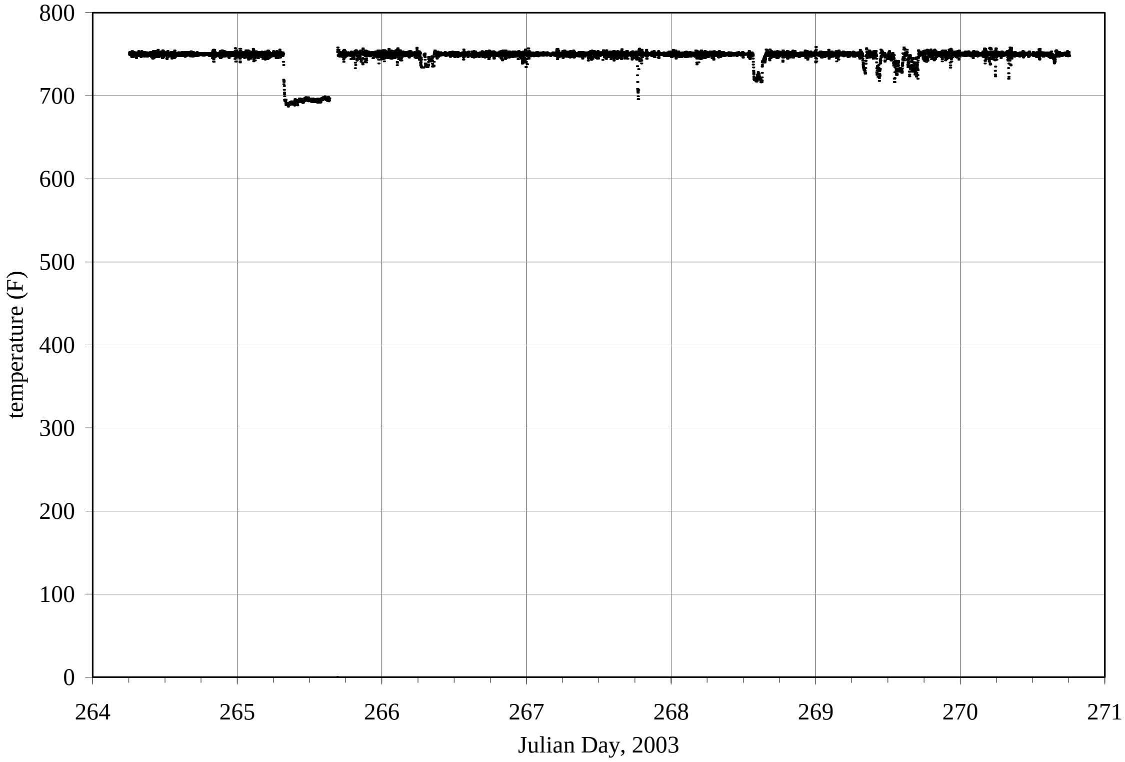


Figure D13. Steam temperature, Boiler 1. Julian Day 264 = September 21, 2003.

Figure D14. Air flow rates in left and right windbox, Boiler 1. Julian Day 264 = September 21, 2003.

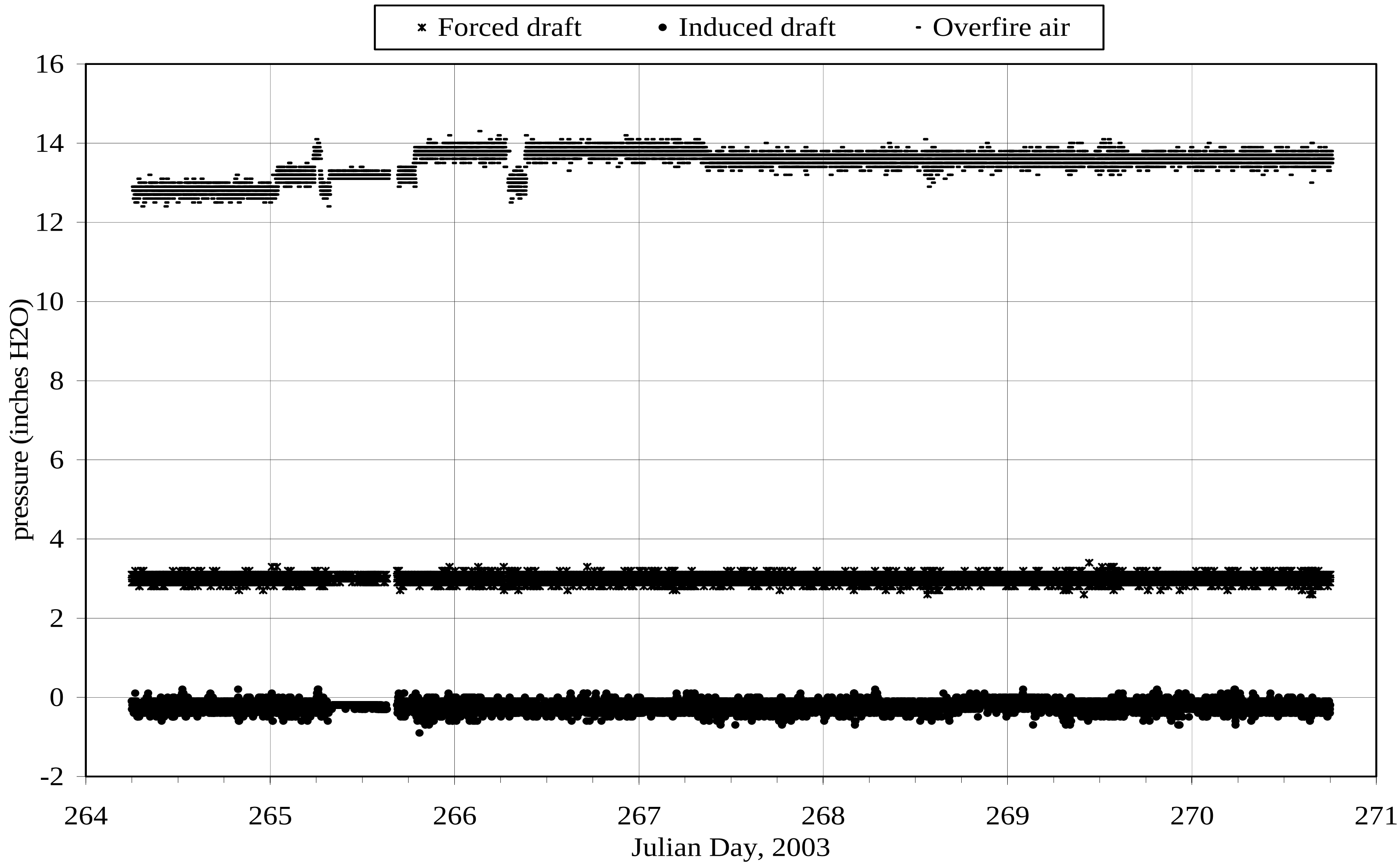


Figure D15. Forced draft, induced draft and overfire air pressure, Boiler 1. Julian Day 264 = September 21, 2003.

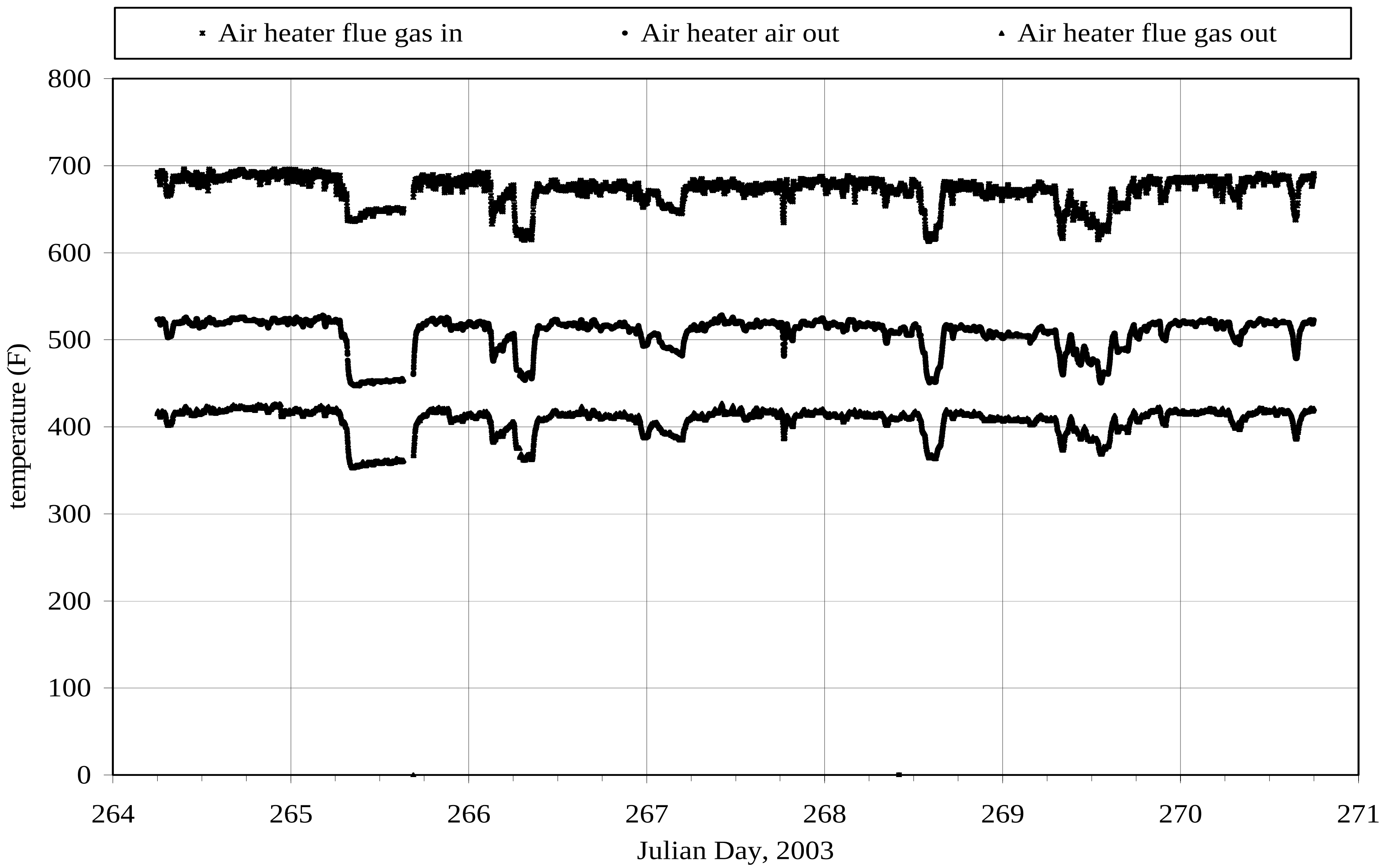


Figure D16. Air heater, flue gas in, flue gas out and air out temperature, Boiler 1. Julian Day 264 = September 21, 2003.

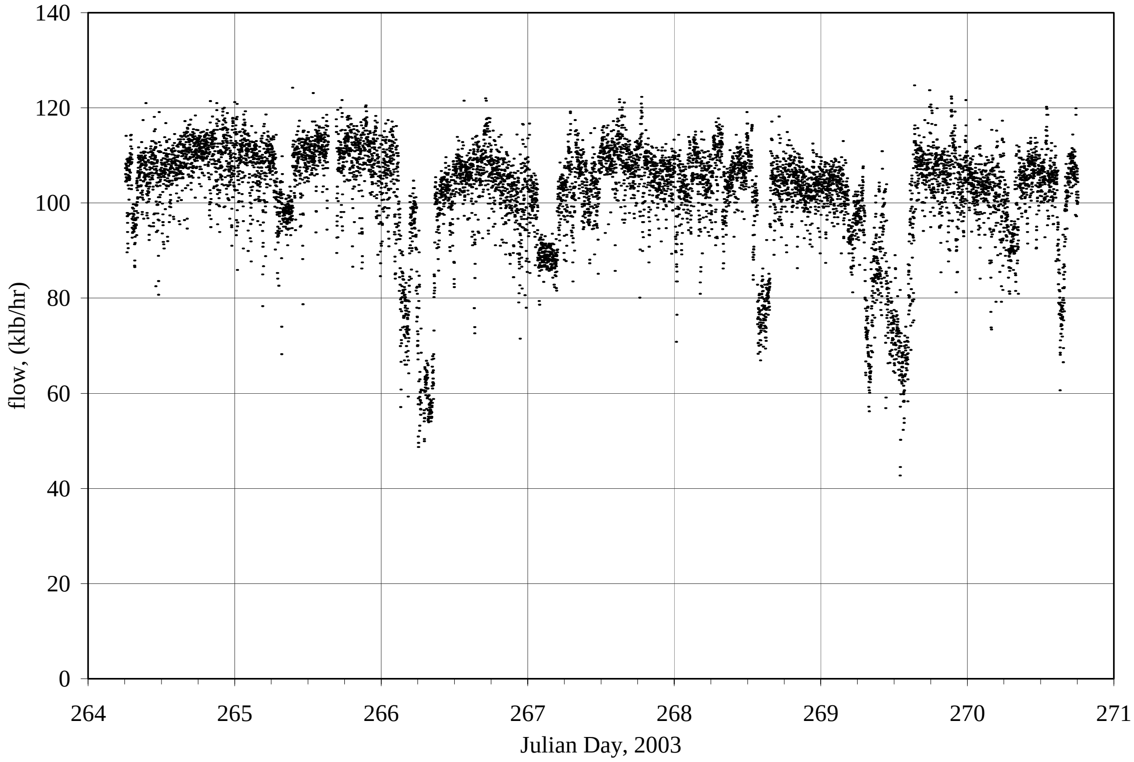


Figure D17. Steam flow rate, Boiler 2. Julian Day 264 = September 21, 2003.

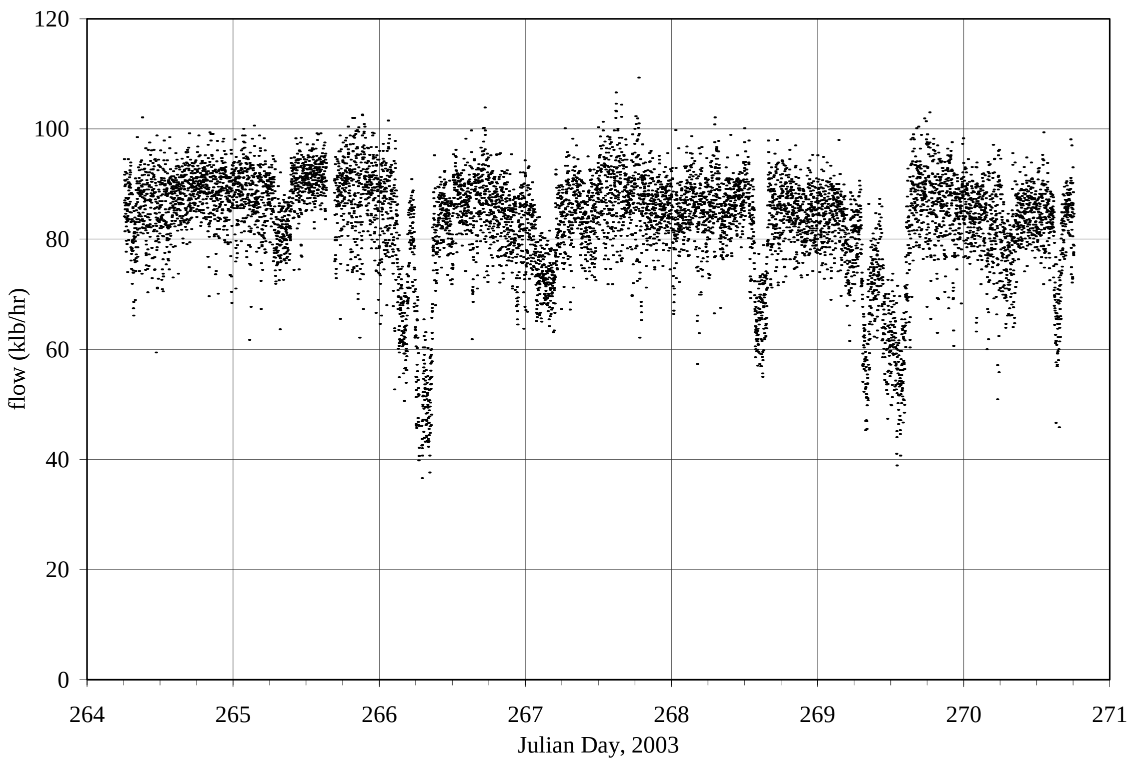


Figure D18. Feed water flow rate, Boiler 2. Julian Day 264 = September 21, 2003.

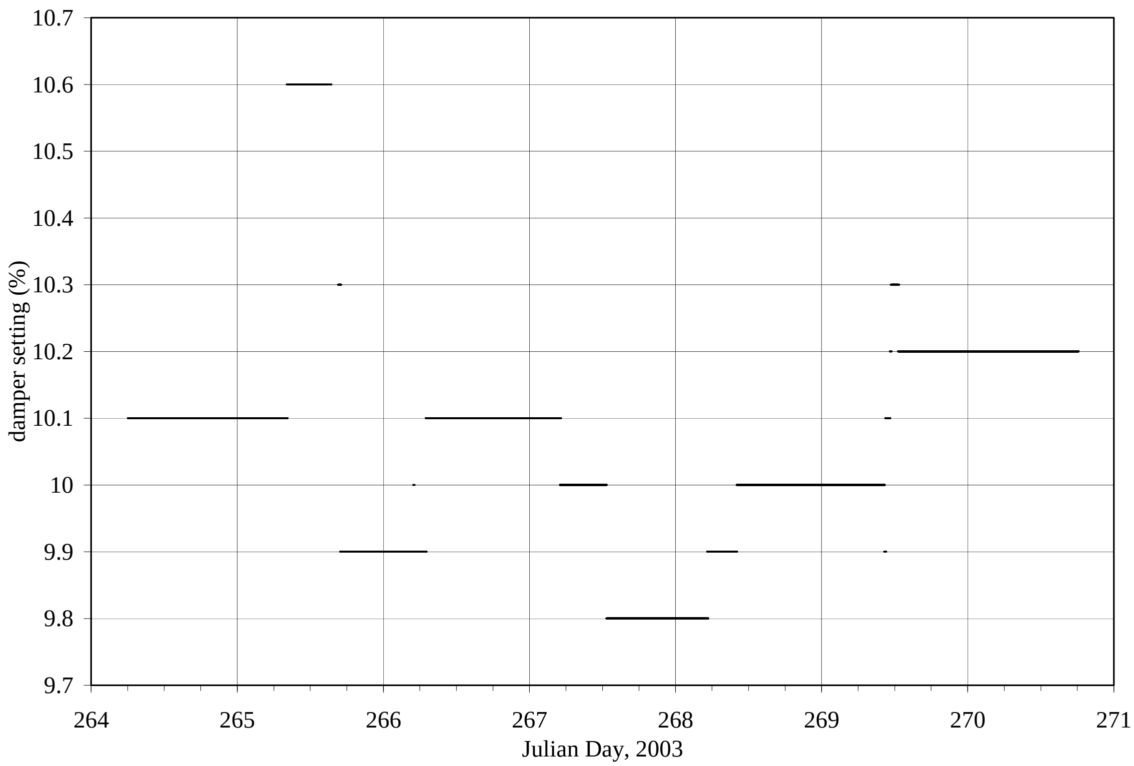


Figure D19. Right grate air flow rate, Boiler 2. Julian Day 264 = September 21, 2003.

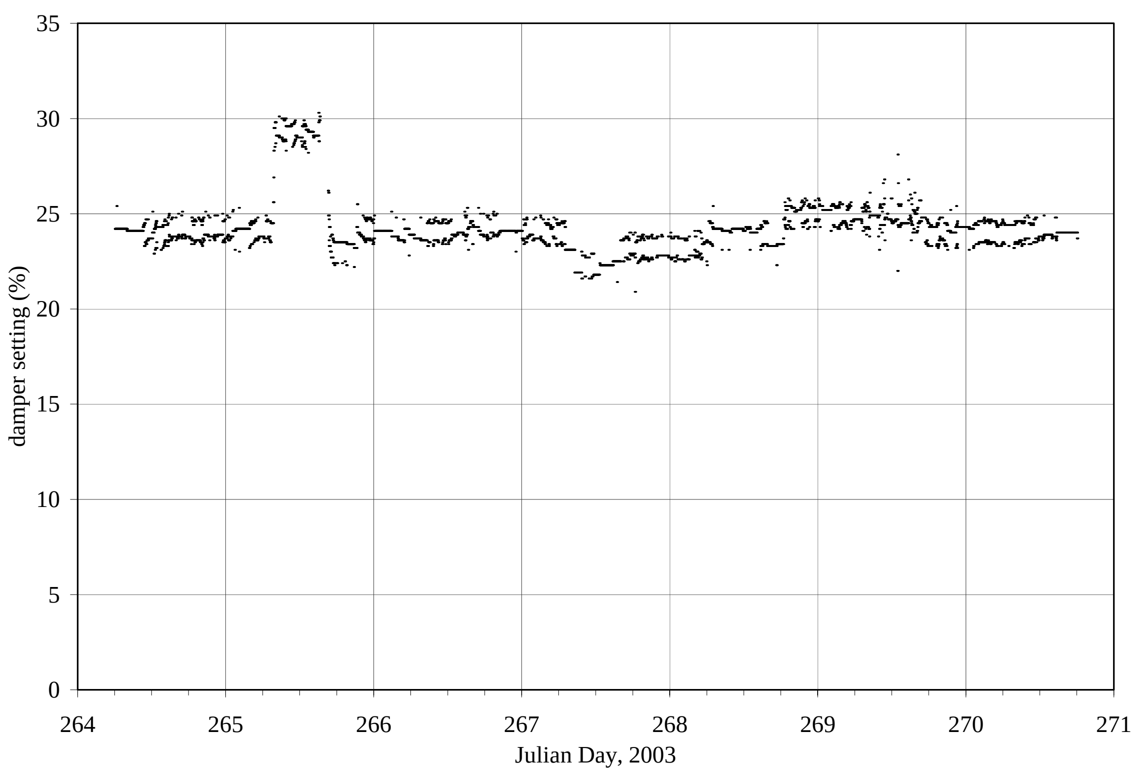


Figure D20. Left grate air flow rate, Boiler 2. Julian Day 264 = September 21, 2003.

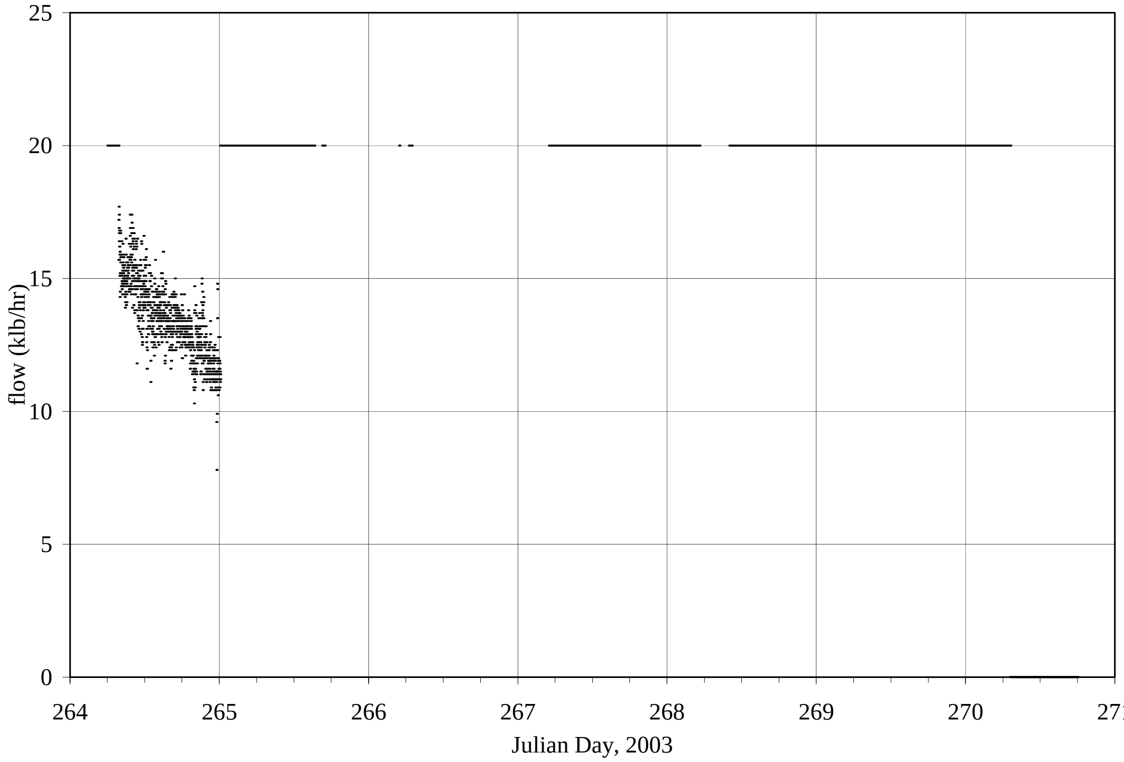


Figure D21. Continuous blowdown flow rate, Boiler 2. Julian Day 264 = September 21, 2003.

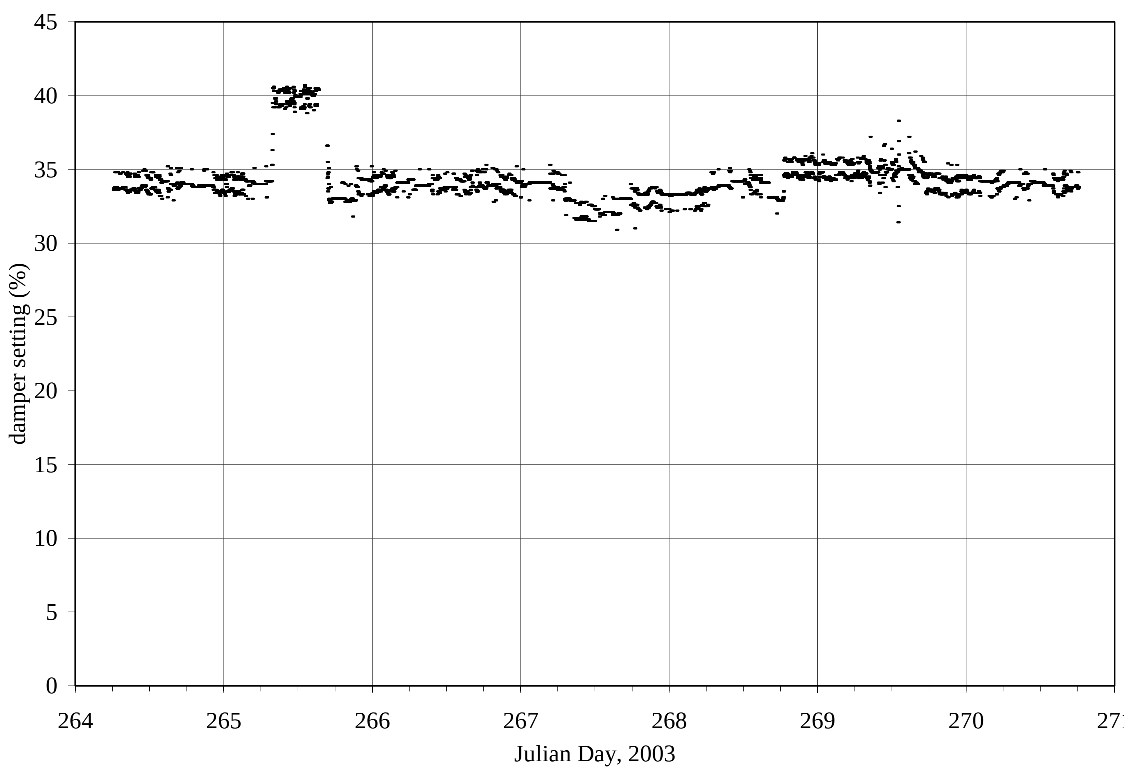


Figure D22. Grate air flow rate, Boiler 2. Julian Day 264 = September 21, 2003.

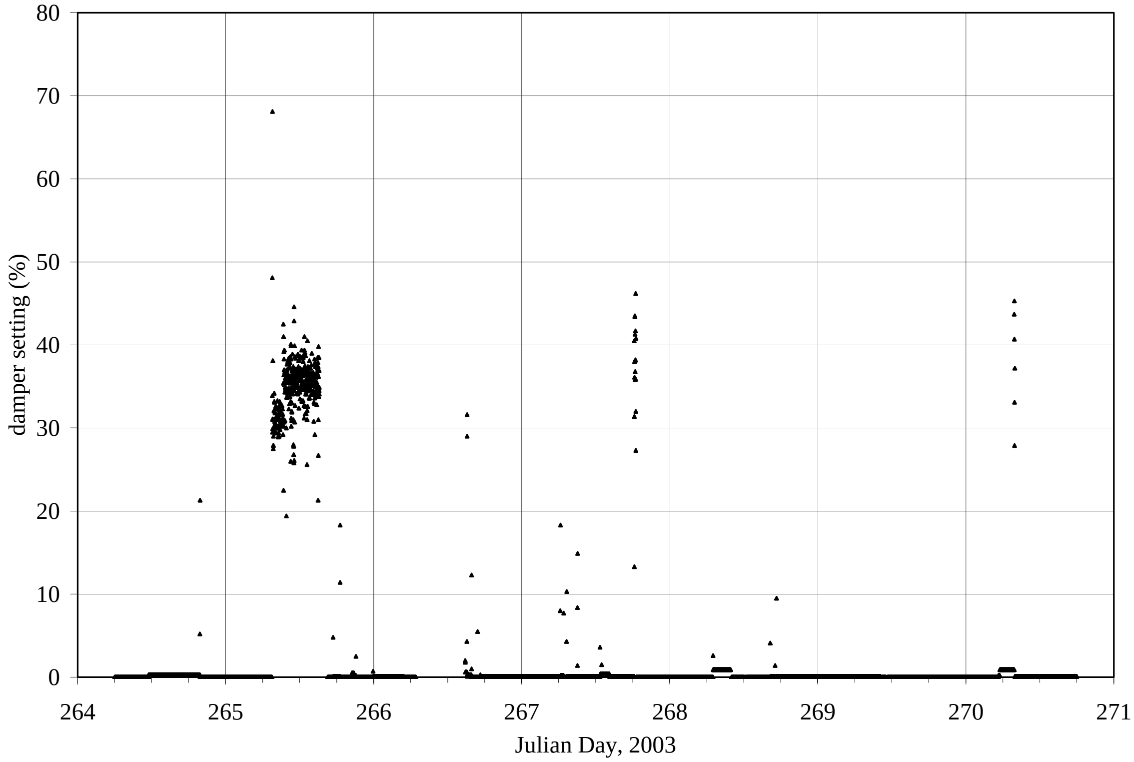


Figure D23. Coal flow rate, Boiler 2. Julian Day 264 = September 21, 2003.

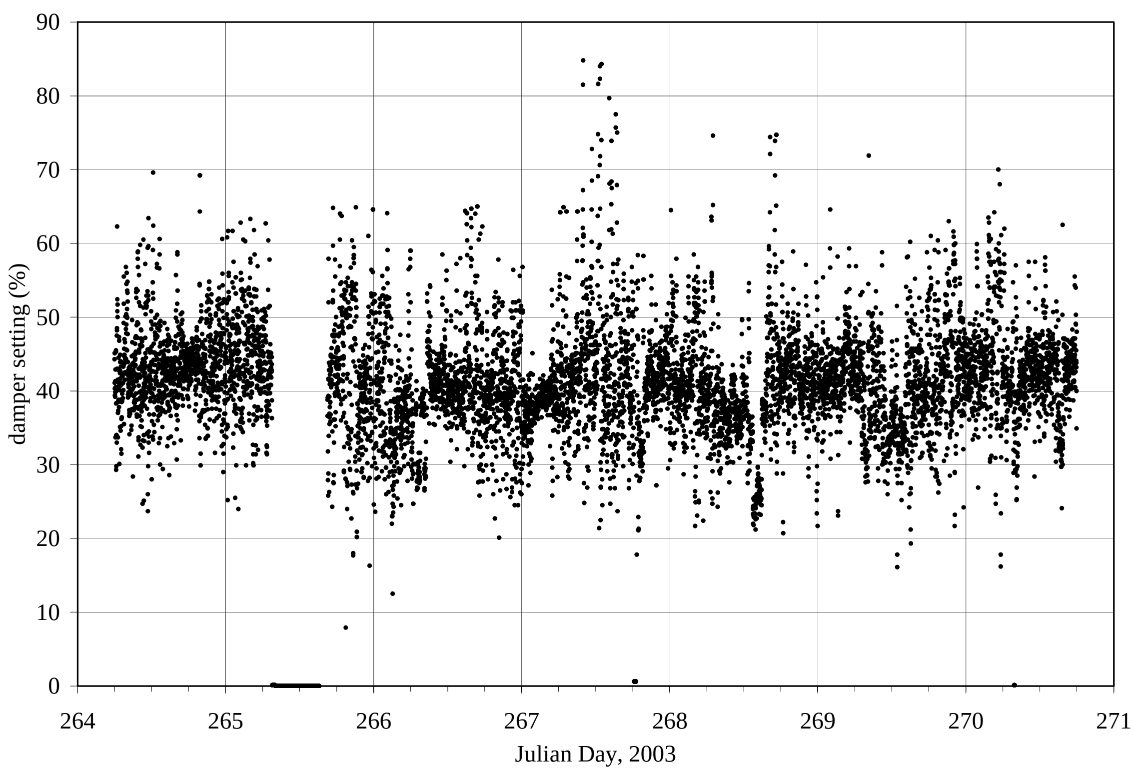


Figure D24. Bagasse feed rate, Boiler 2. Julian Day 264 = September 21, 2003.

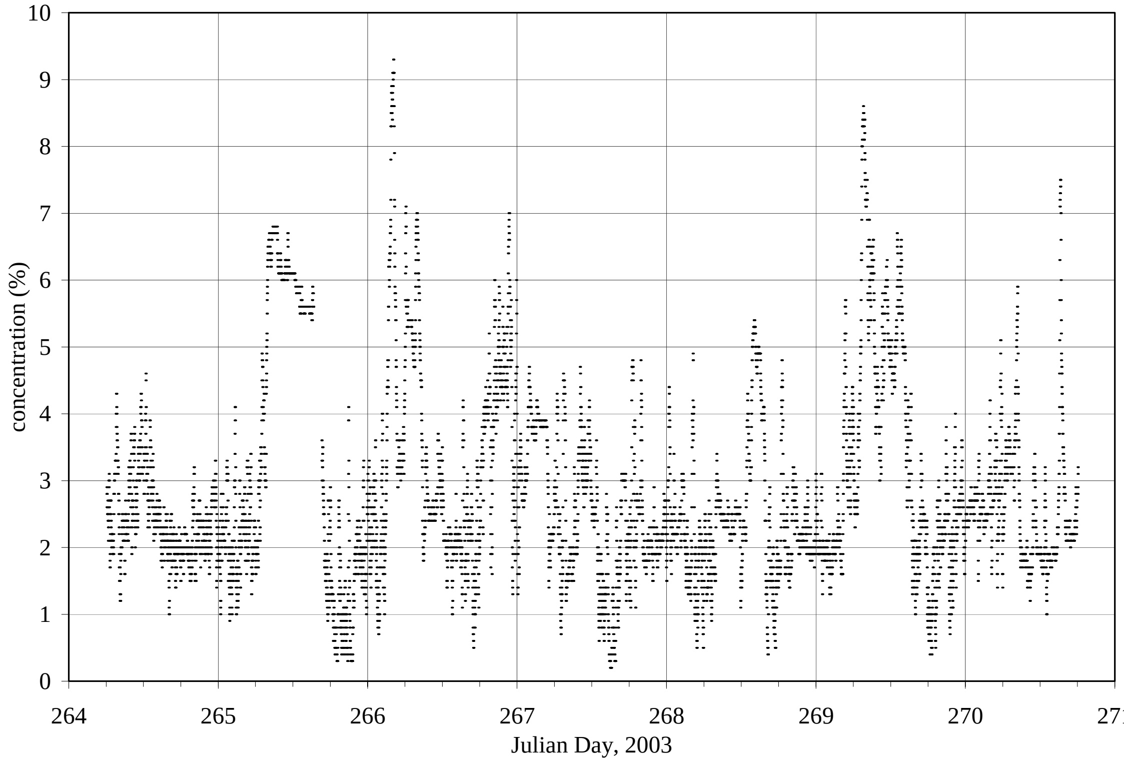


Figure D25. O_2 concentration, Boiler 2. Julian Day 264 = September 21, 2003.

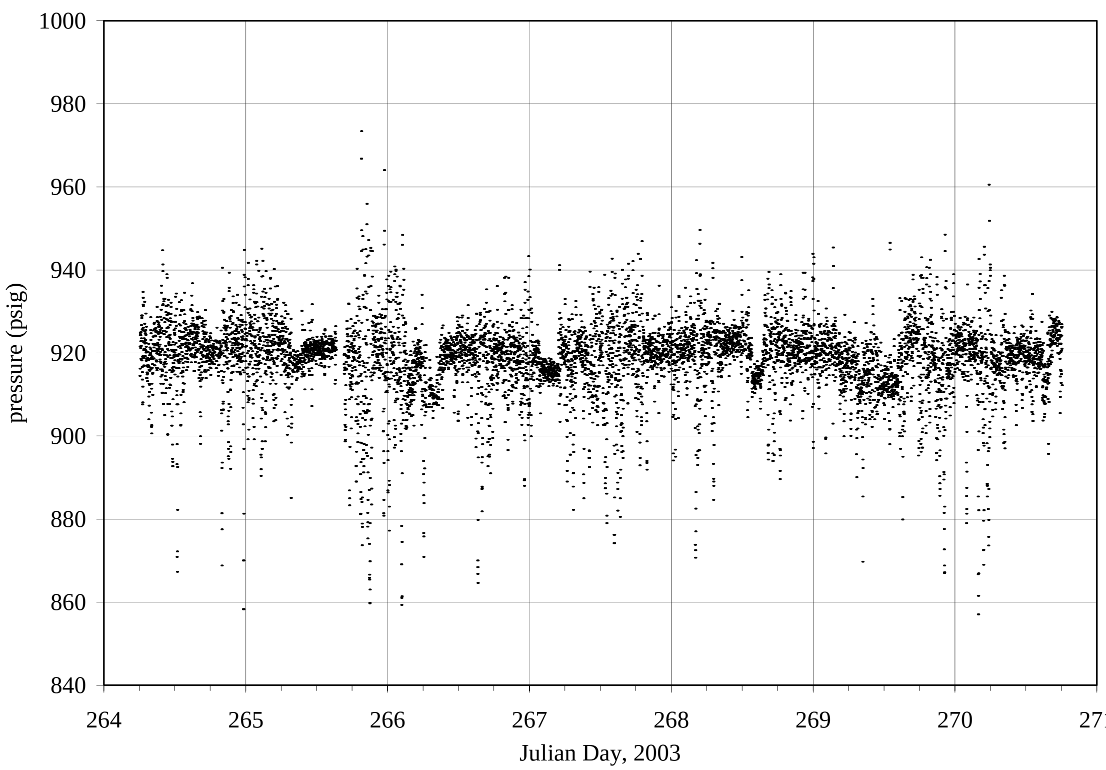


Figure D26. Drum pressure, Boiler 2. Julian Day 264 = September 21, 2003.

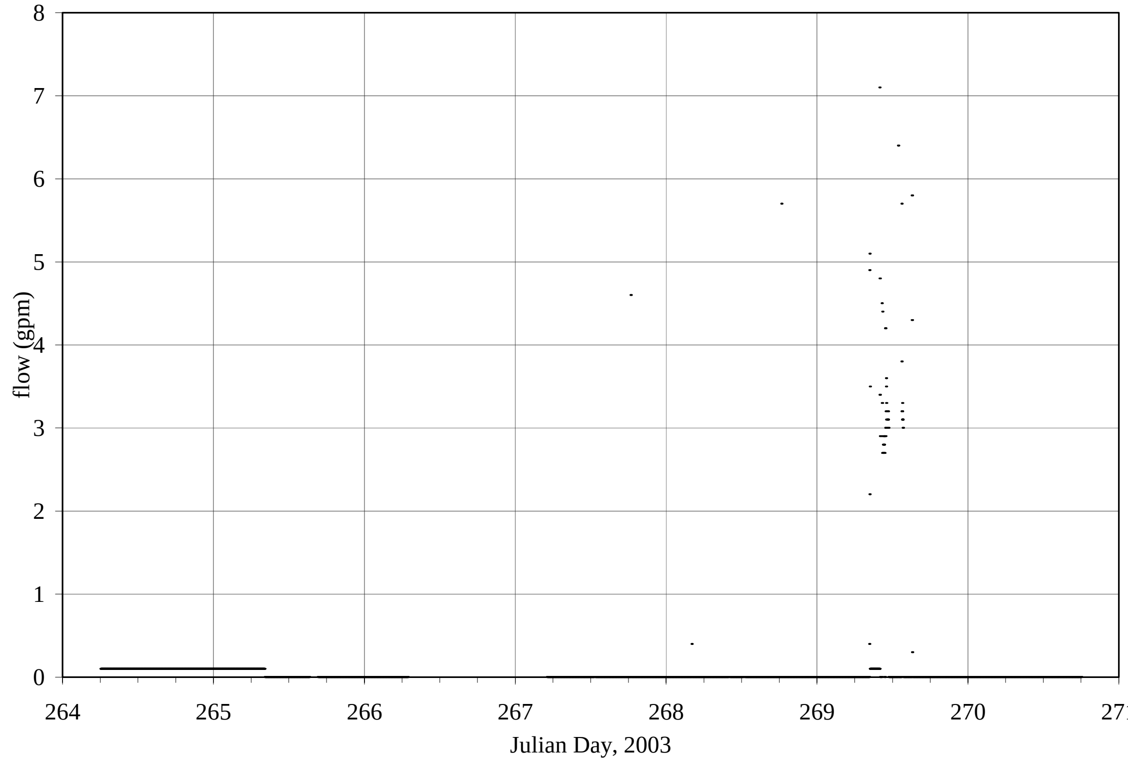


Figure D27. Fuel Oil flow rate, Boiler 2. Julian Day 264 = September 21, 2003.

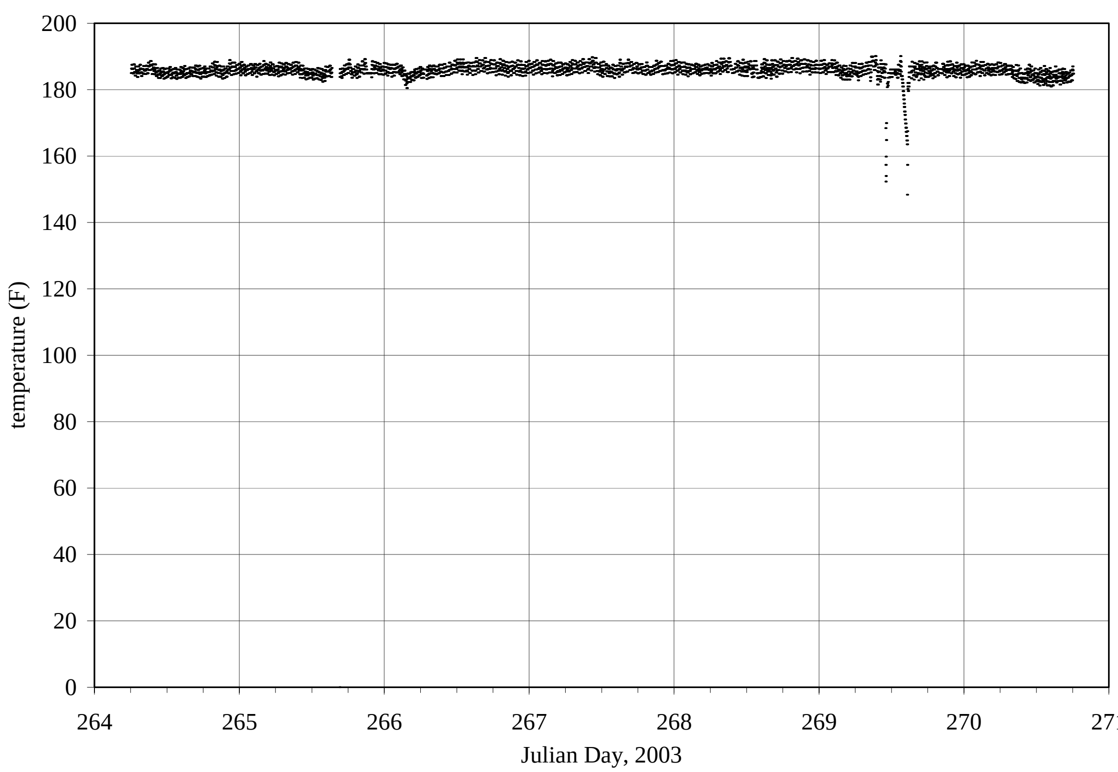


Figure D28. Fuel Oil temperature, Boiler 2. Julian Day 264 = September 21, 2003.

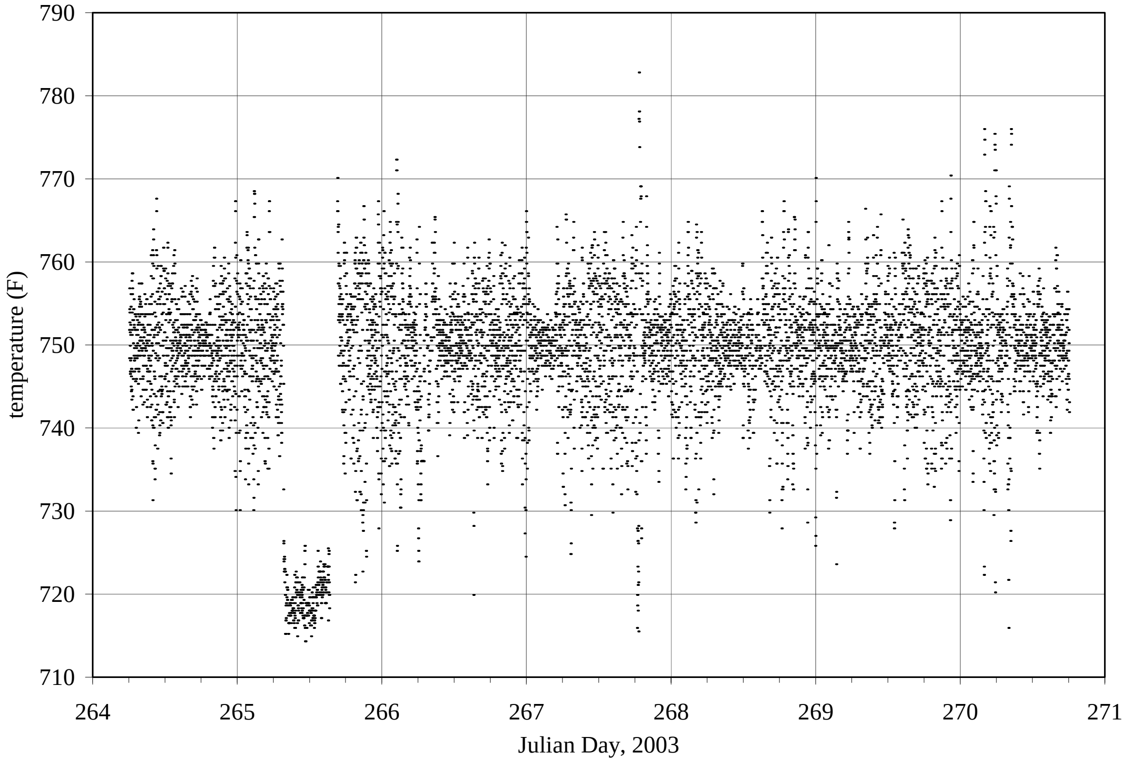


Figure D29. Steam temperature, Boiler 2. Julian Day 264 = September 21, 2003.

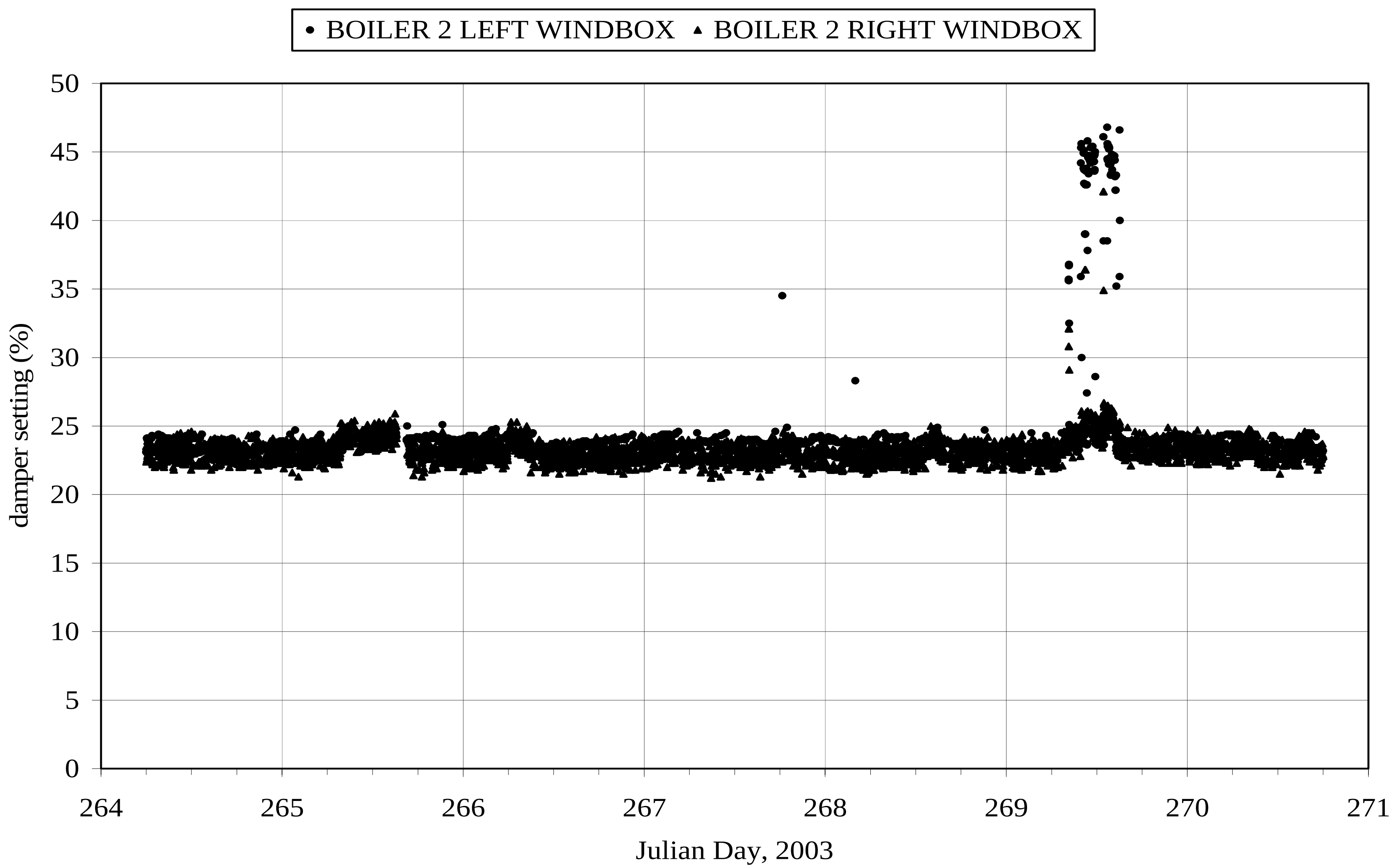


Figure D30. Air flow rates in left and right windbox, Boiler 2. Julian Day 264 = September 21, 2003.

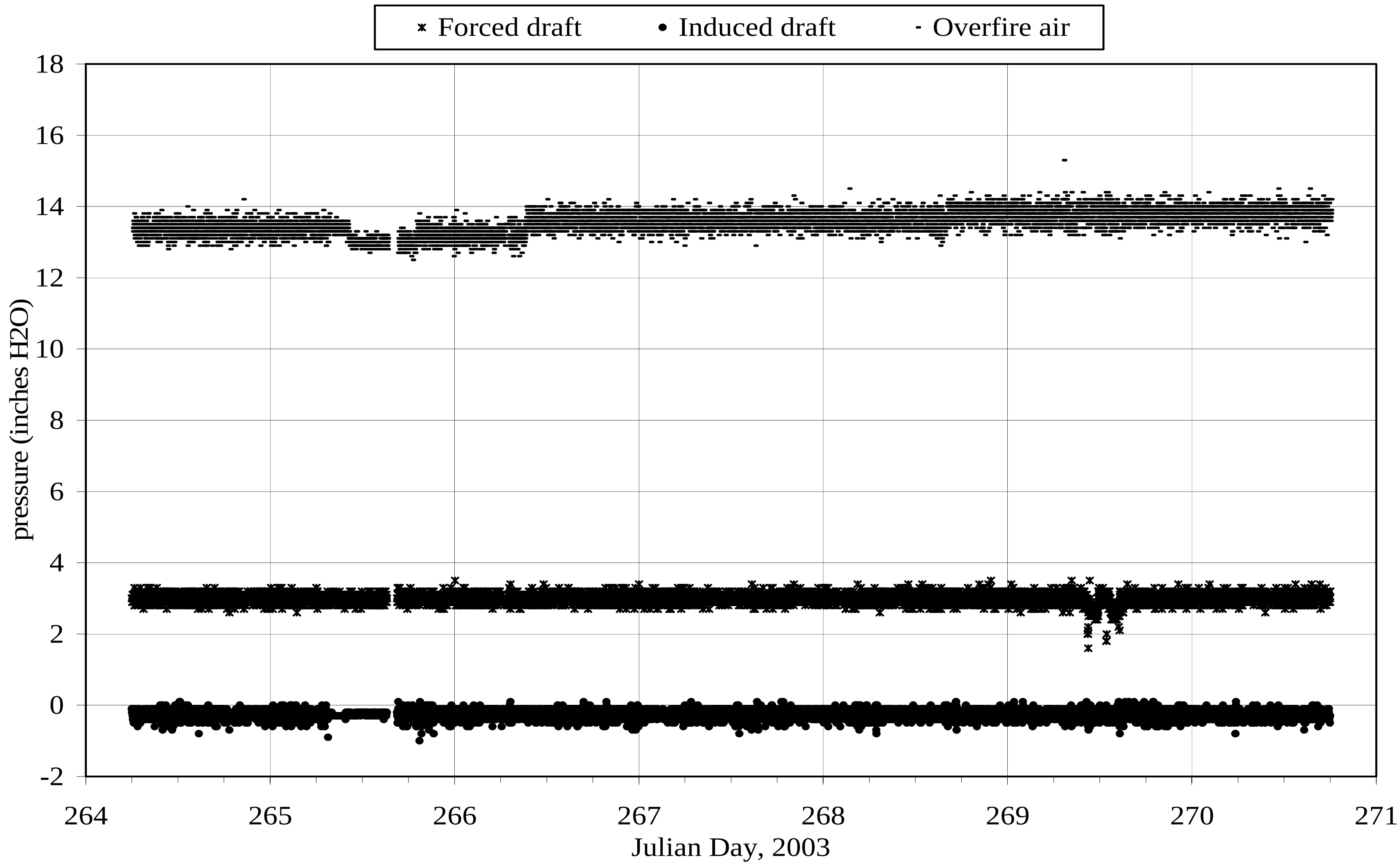


Figure D31. Forced draft, induced draft and overfire air pressure, Boiler 2. Julian Day 264 = September 21, 2003.

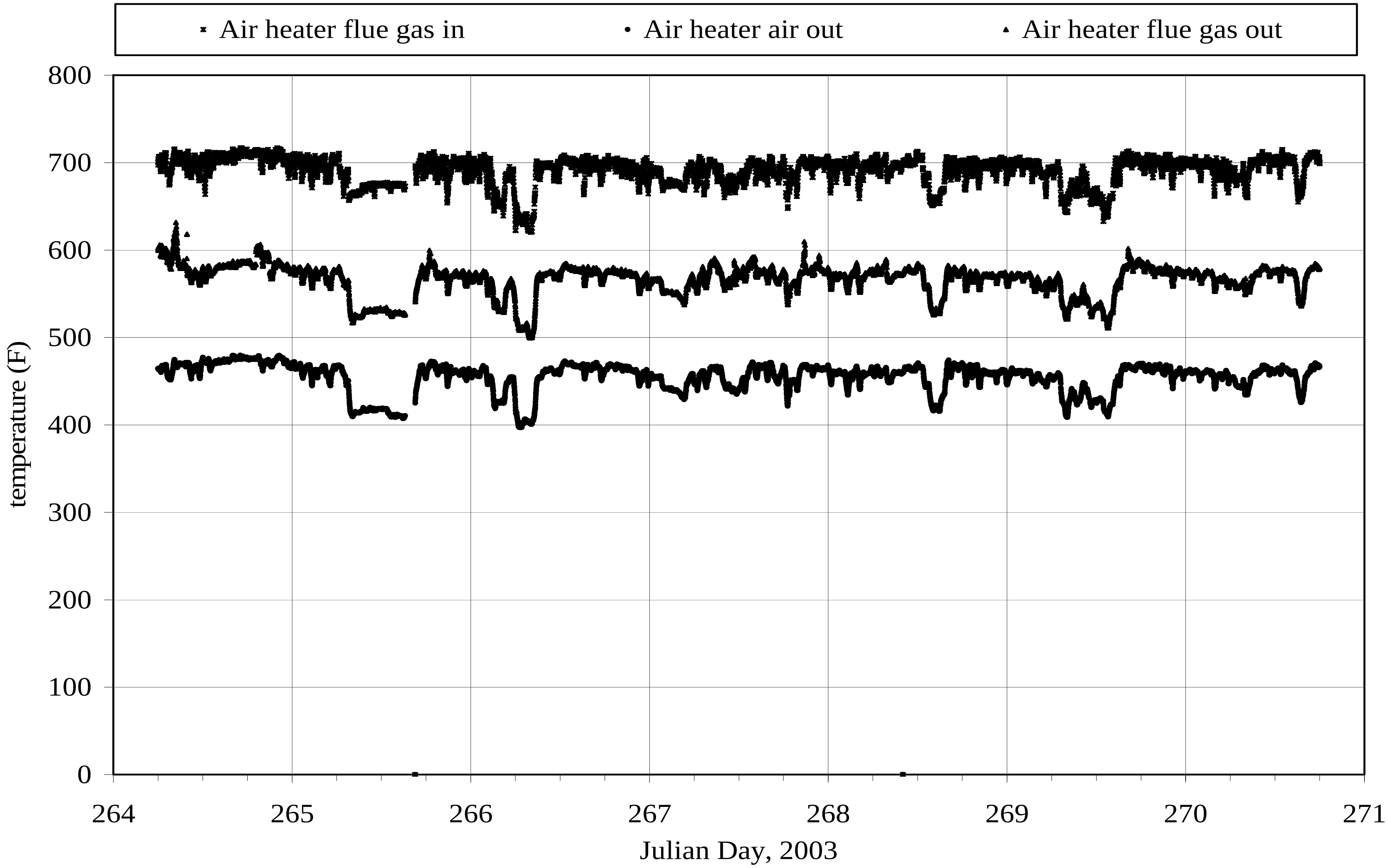


Figure D32. Air heater, flue gas in, flue gas out and air out temperature, Boiler 2. Julian Day 264 = September 21, 2003.

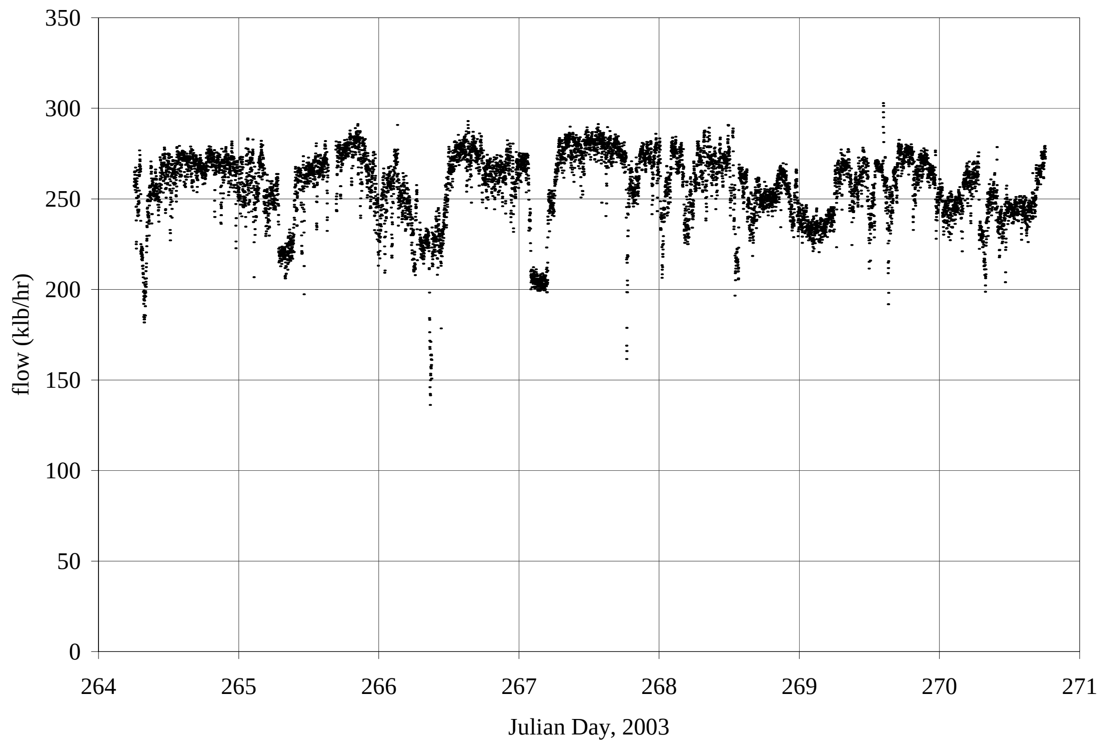


Figure D33. Steam flow rate, Boiler 3. Julian Day 264 = September 21, 2003.

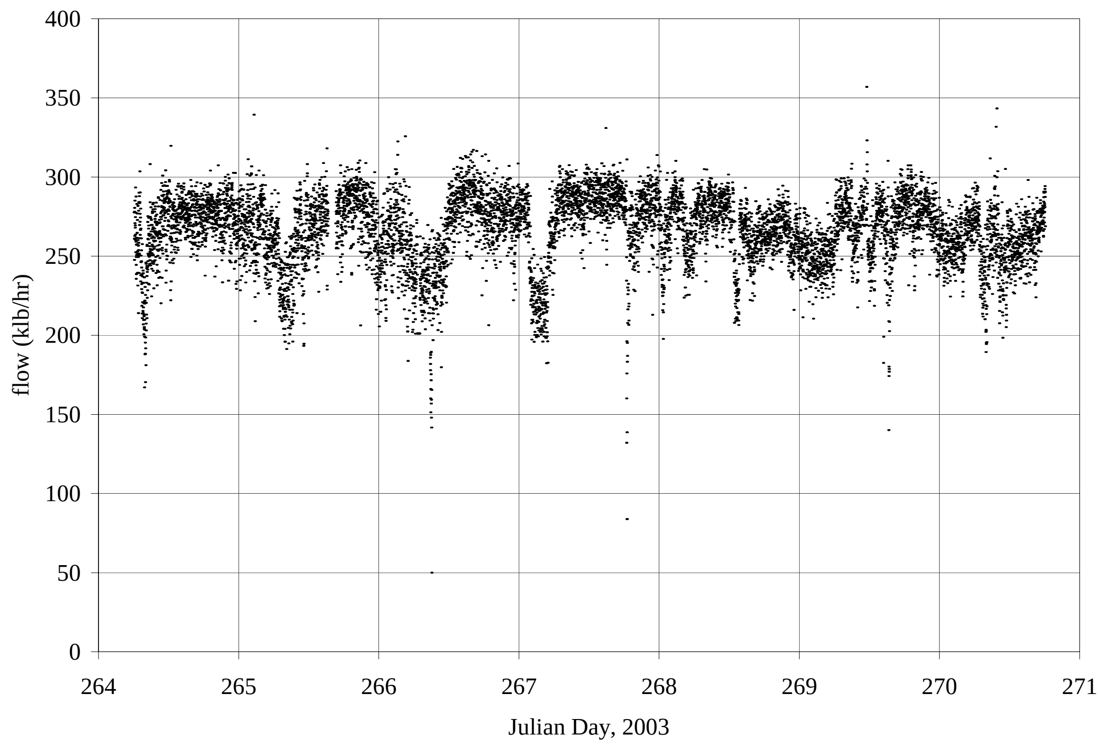


Figure D34. Feed water flow rate, Boiler 3. Julian Day 264 = September 21, 2003.

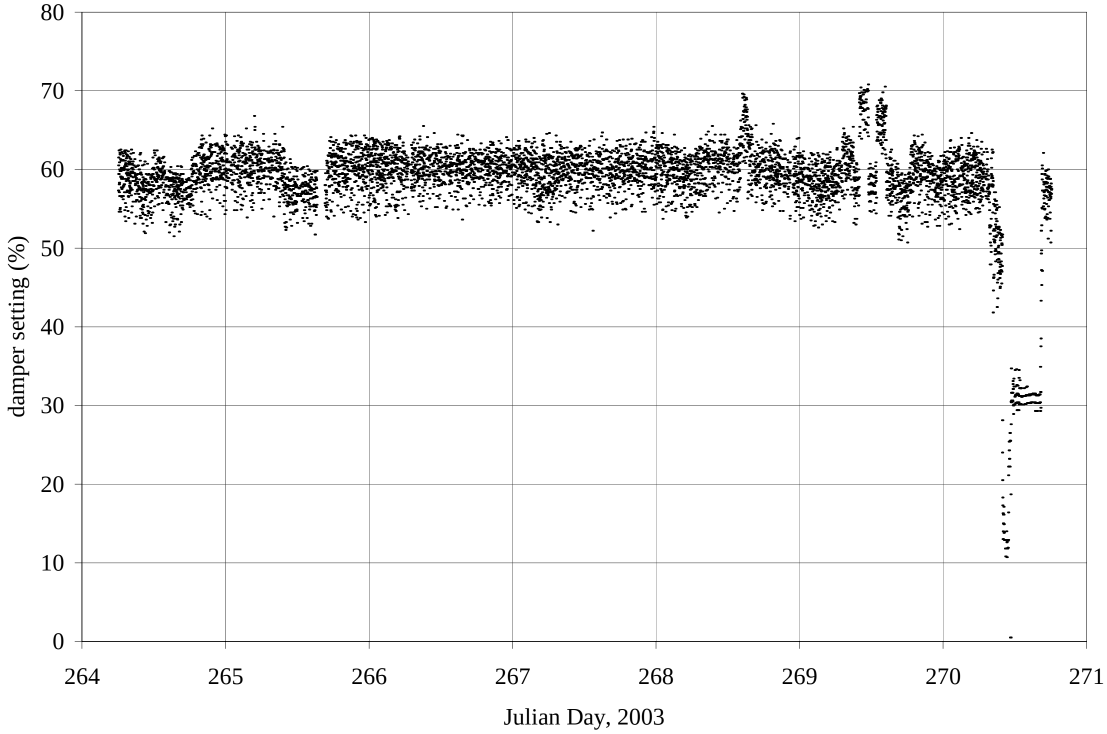


Figure D35. Right grate air flow rate, Boiler 3. Julian Day 264 = September 21, 2003.

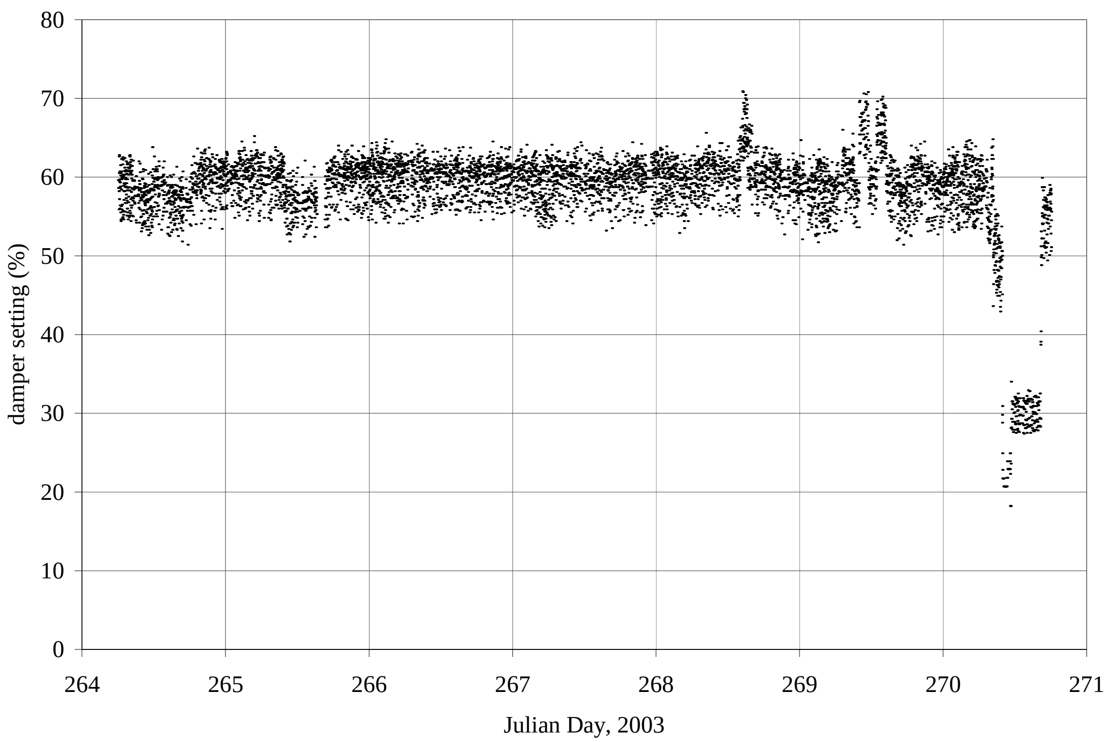


Figure D36. Left grate air flow rate, Boiler 3. Julian Day 264 = September 21, 2003.

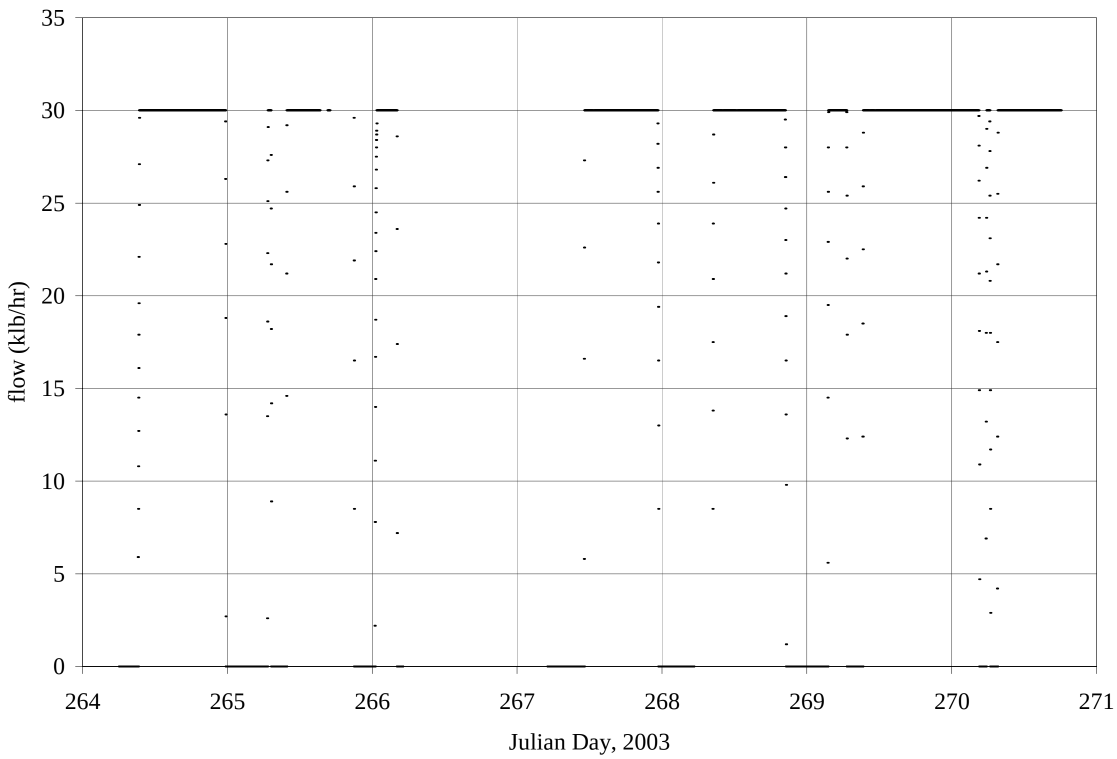


Figure D37. Continuous blowdown flow rate, Boiler 3. Julian Day 264 = September 21, 2003.

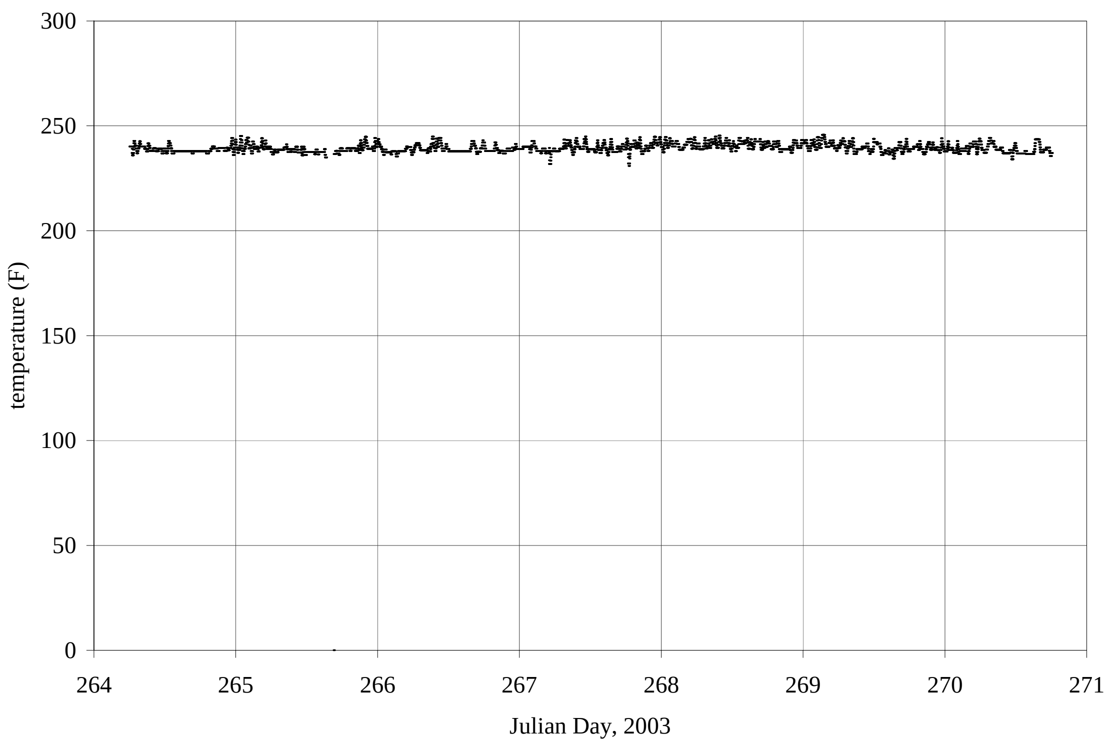


Figure D38. Feedwater temperature, Boiler 3. Julian Day 264 = September 21, 2003.

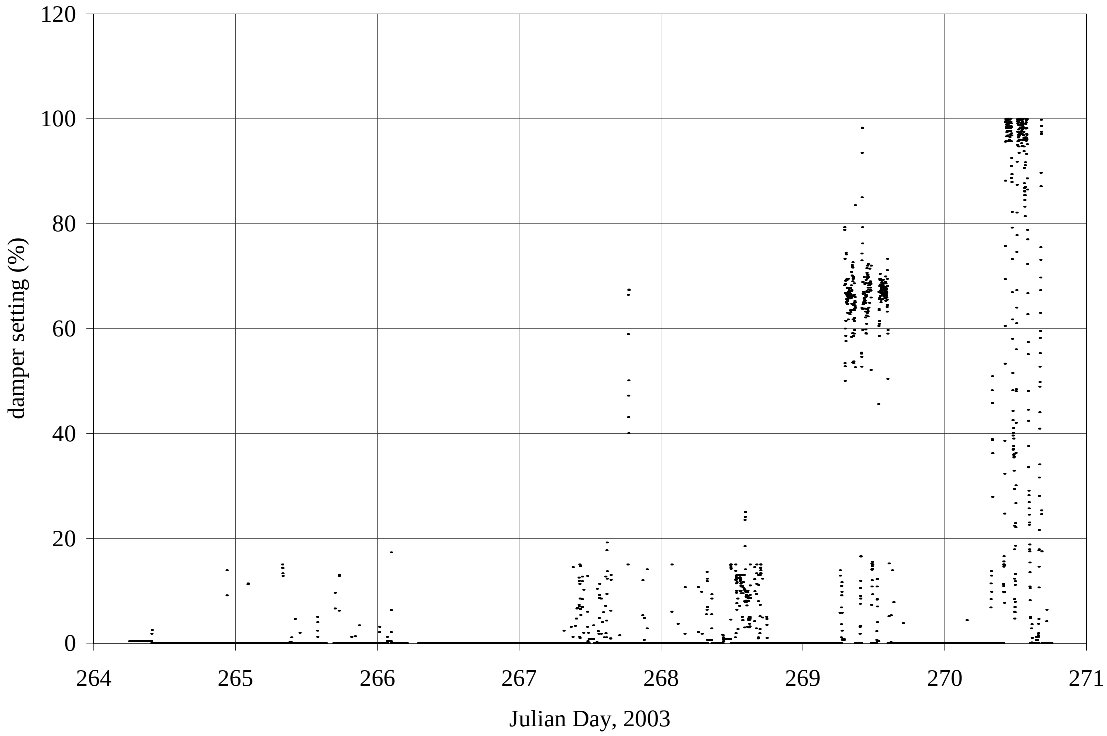


Figure D39. Coal flow rate, Boiler 3. Julian Day 264 = September 21, 2003.

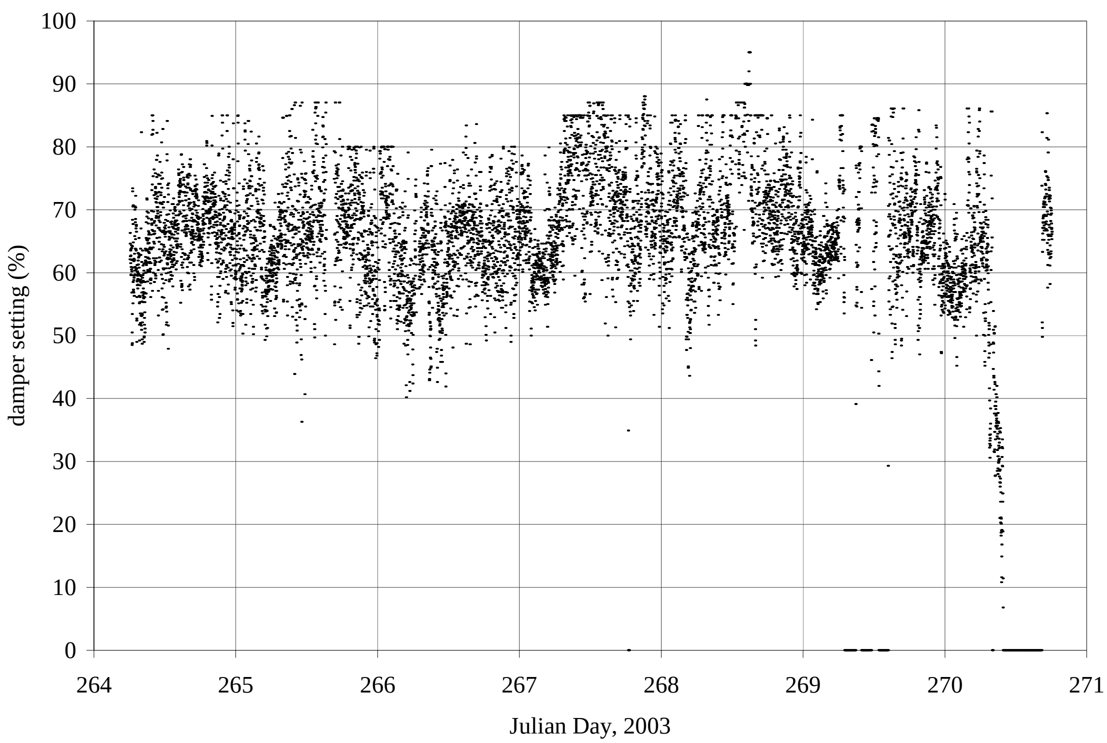


Figure D40. Bagasse feed rate, Boiler 3. Julian Day 264 = September 21, 2003.

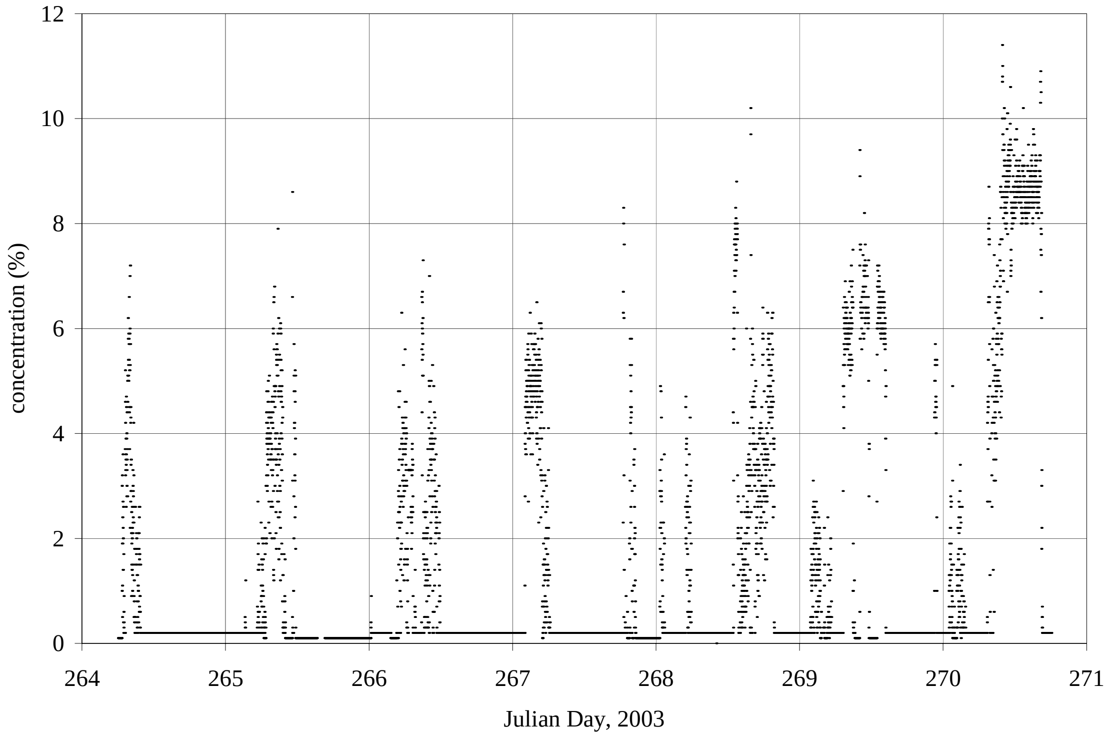


Figure D41. O_2 concentration, Boiler 3. Julian Day 264 = September 21, 2003.

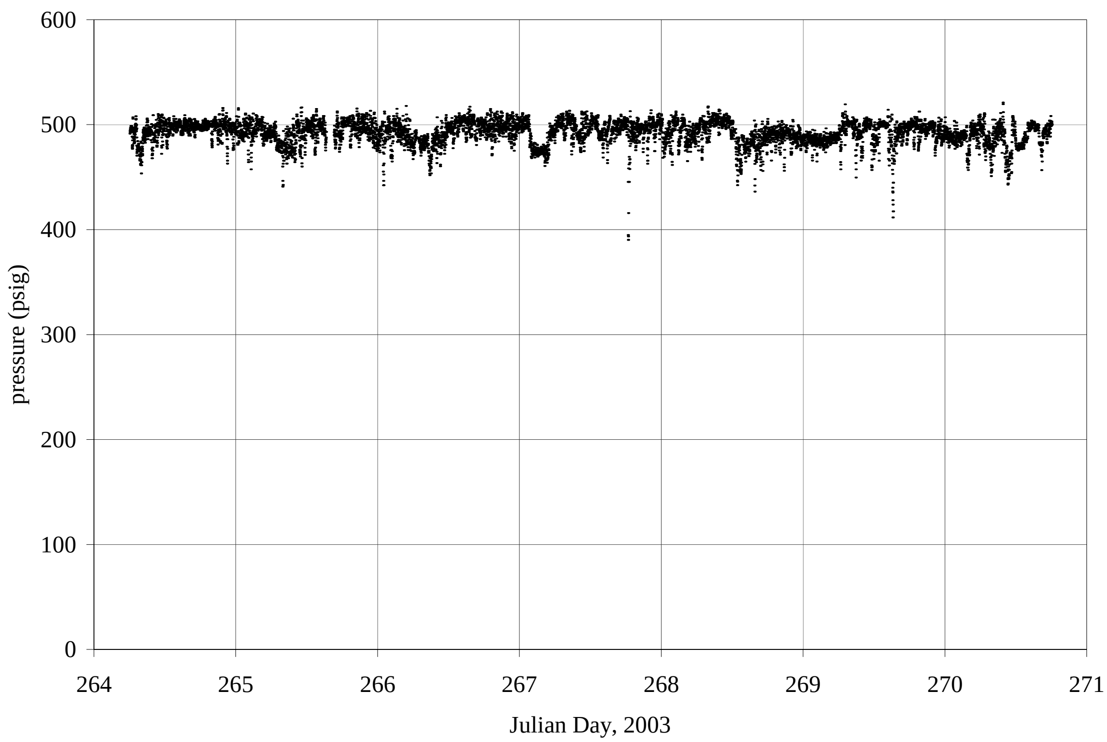


Figure D42. Drum pressure, Boiler 3. Julian Day 264 = September 21, 2003.

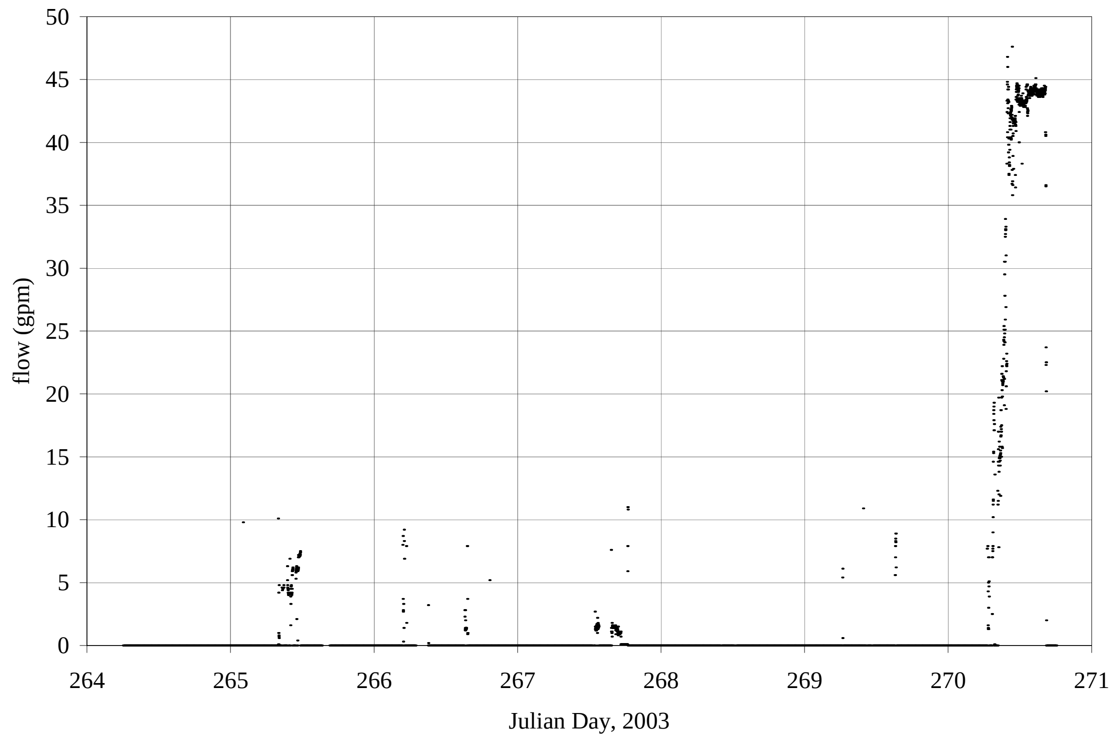


Figure D43. Fuel Oil flow rate, Boiler 3. Julian Day 264 = September 21, 2003.

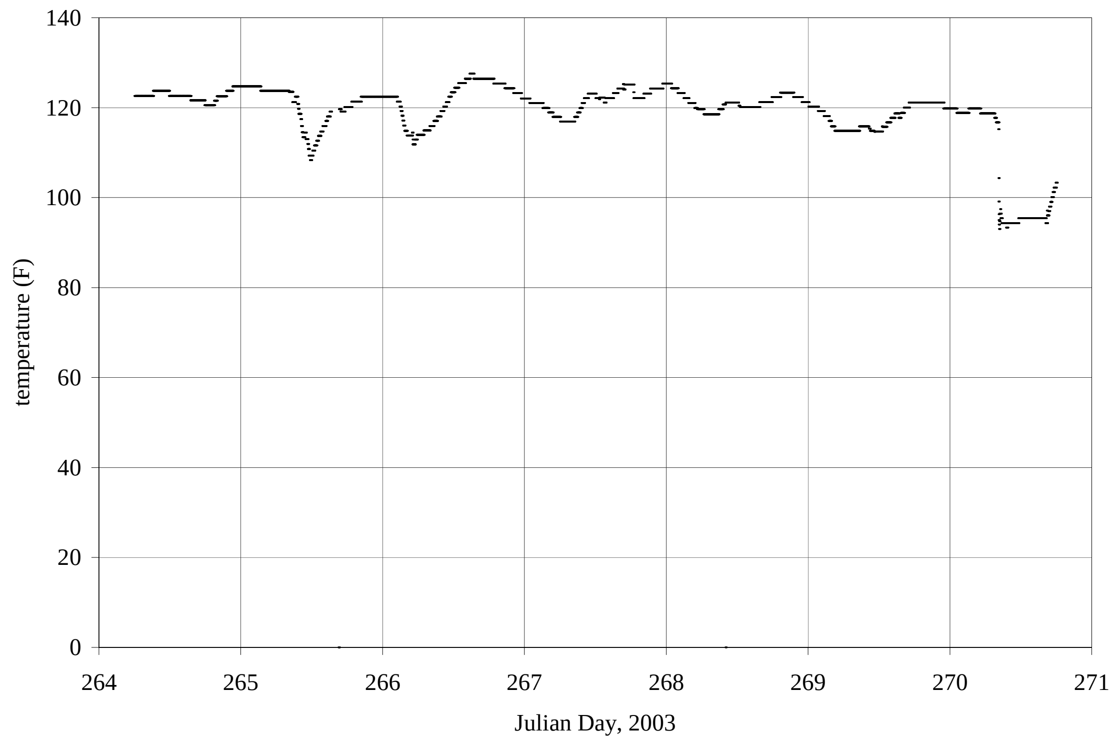


Figure D44. Fuel Oil temperature, Boiler 3. Julian Day 264 = September 21, 2003.

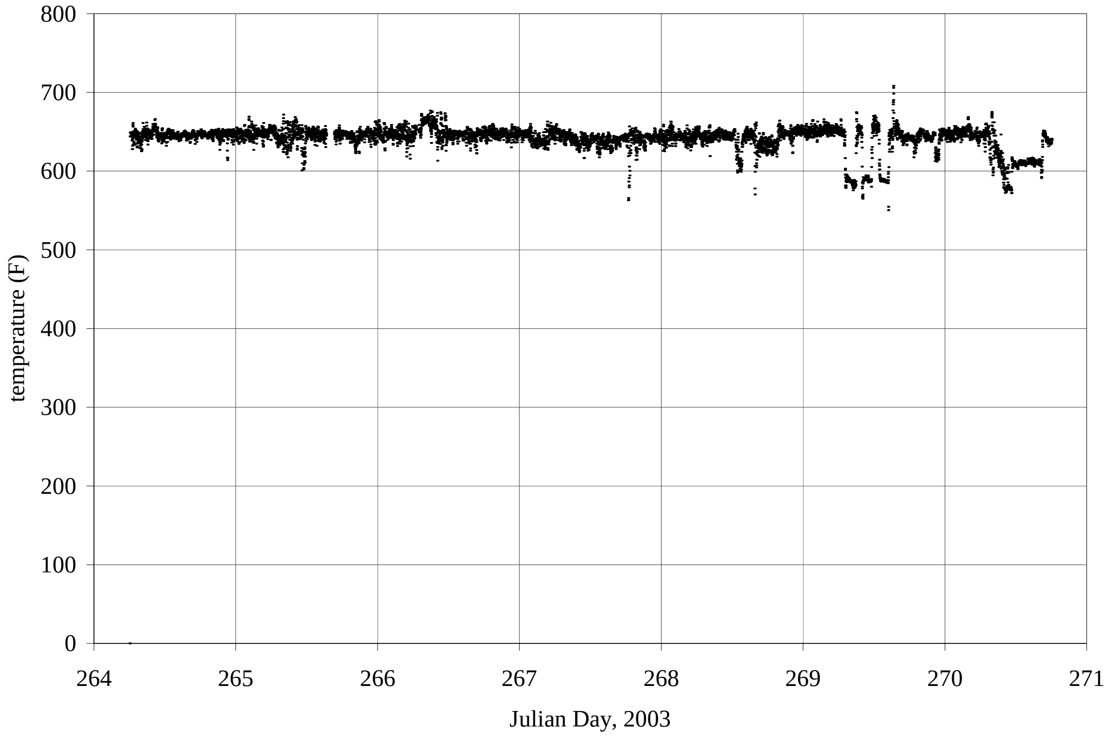


Figure D45. Primary steam temperature, Boiler 3. Julian Day 264 = September 21, 2003.

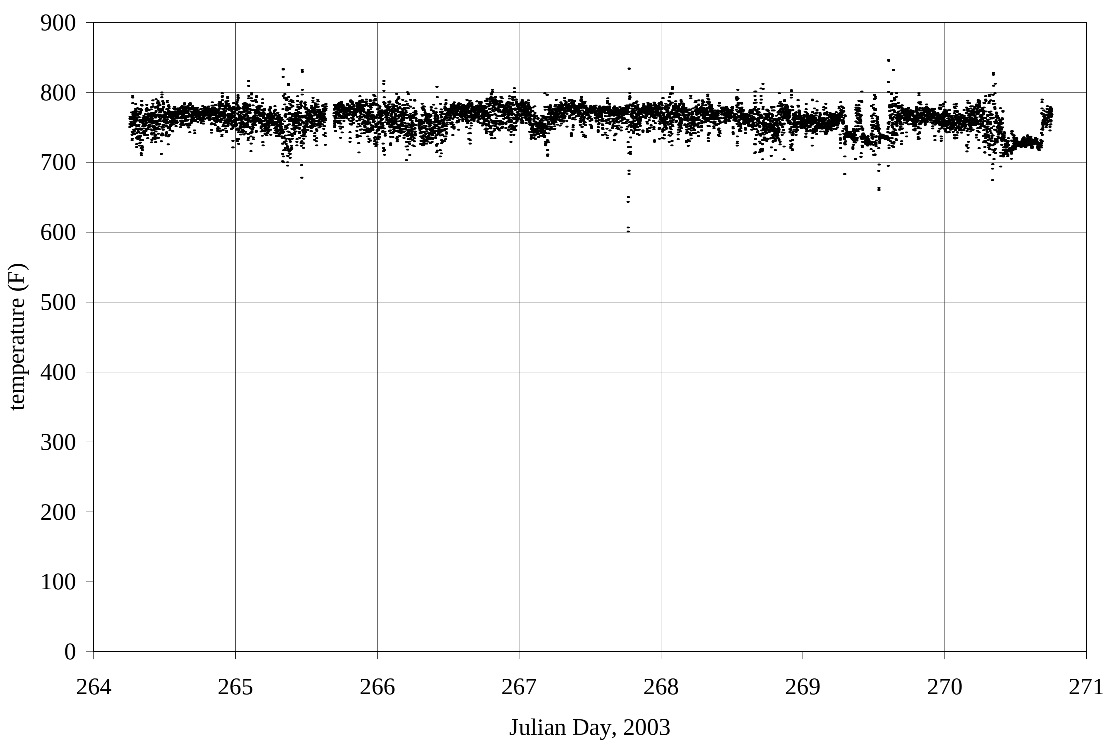


Figure D46. Final steam temperature, Boiler 3. Julian Day 264 = September 21, 2003.

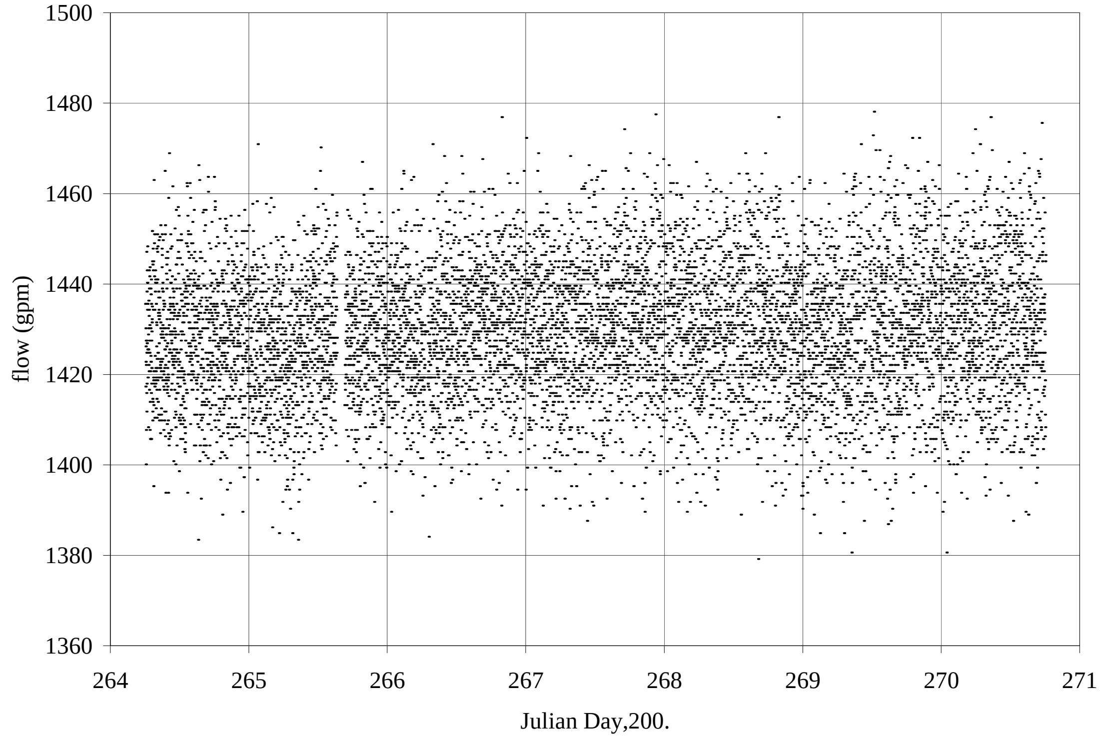


Figure D47. Wet scrubber flow rate, Boiler 3. Julian Day 264 = September 21, 2003.

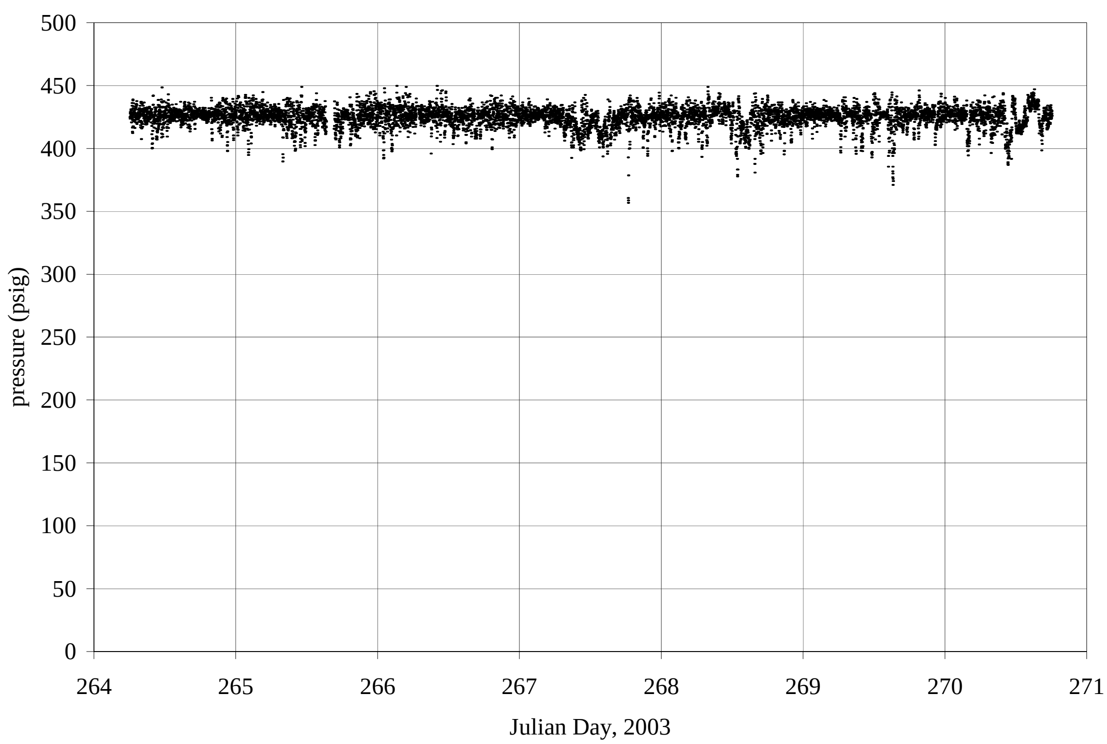


Figure D48. Steam header pressure, Boiler 3. Julian Day 264 = September 21, 2003.

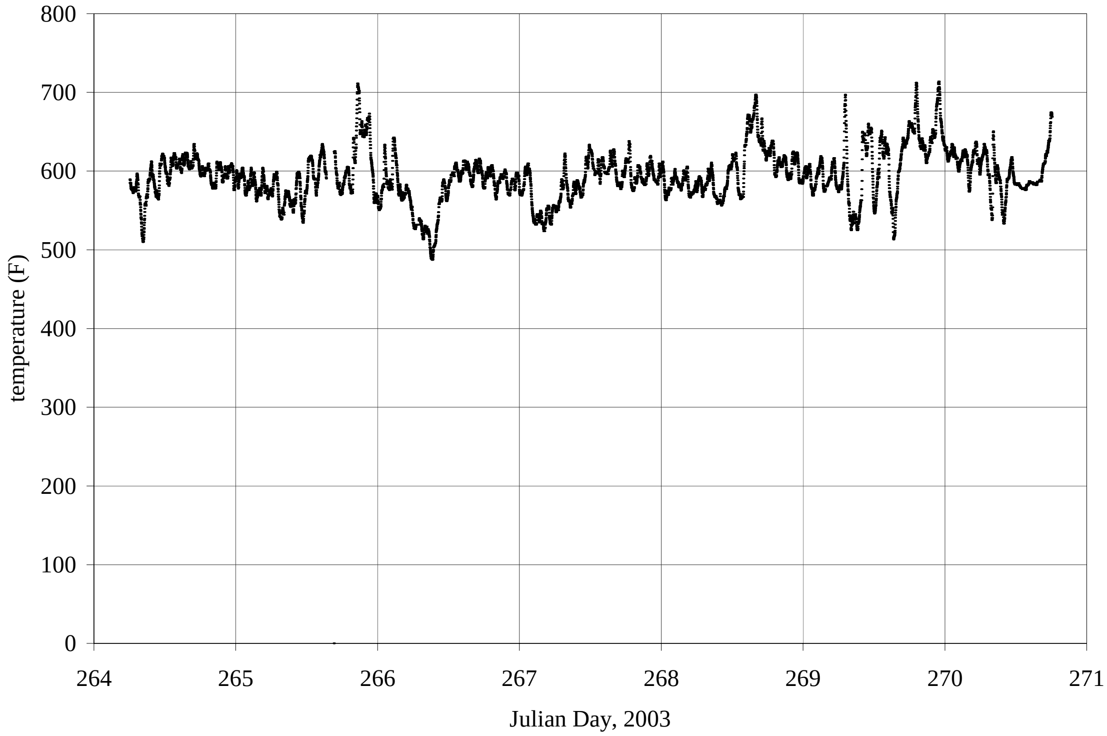


Figure D49. Grate temperature at thermocouple #1, Boiler 3. Julian Day 264 = September 21, 2003.

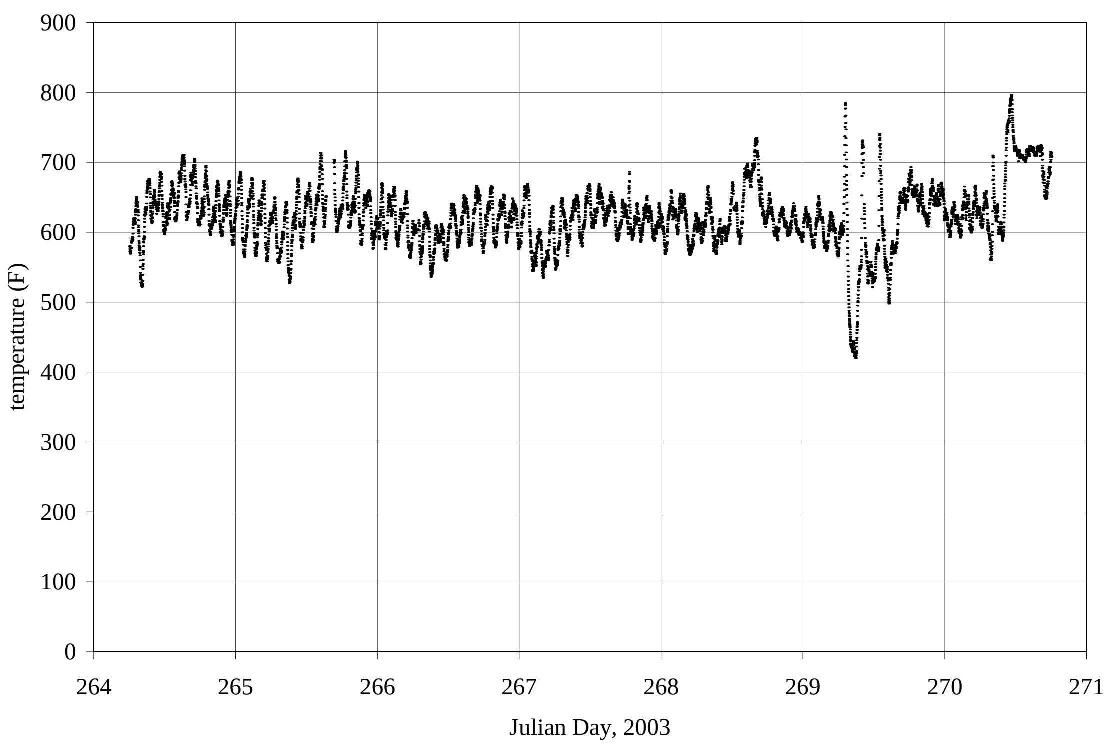


Figure D50. Grate temperature at thermocouple #2, Boiler 3. Julian Day 264 = September 21, 2003.

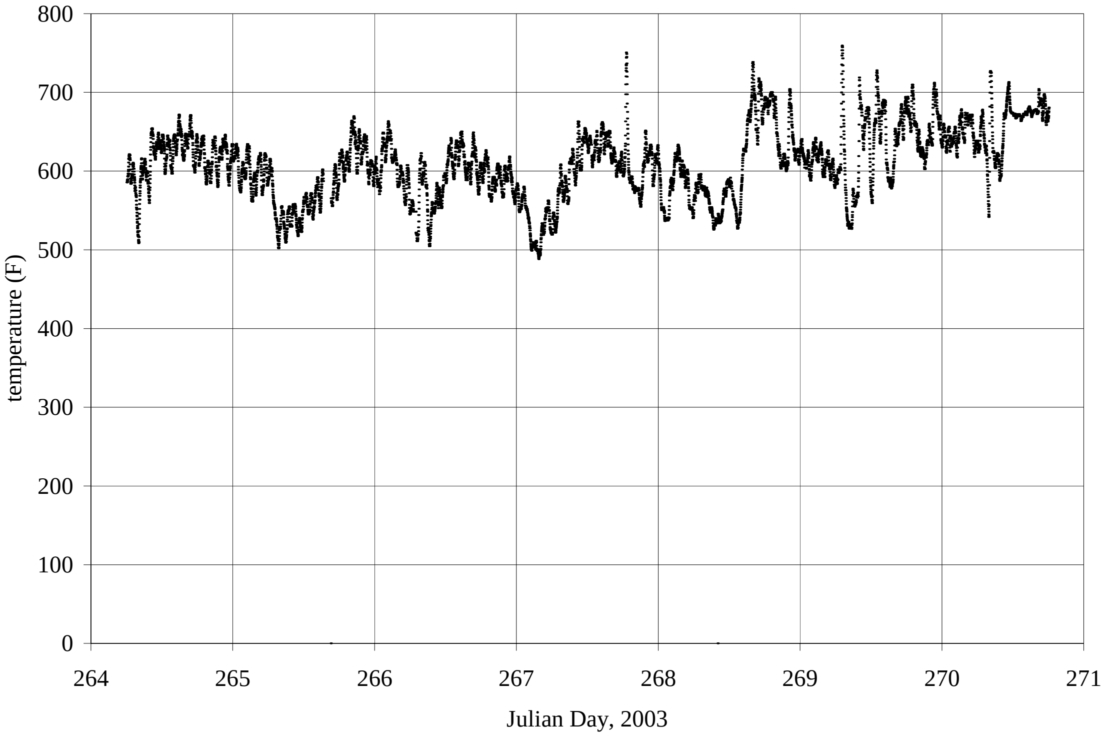


Figure D51. Grate temperature at thermocouple #3, Boiler 3. Julian Day 264 = September 21, 2003.

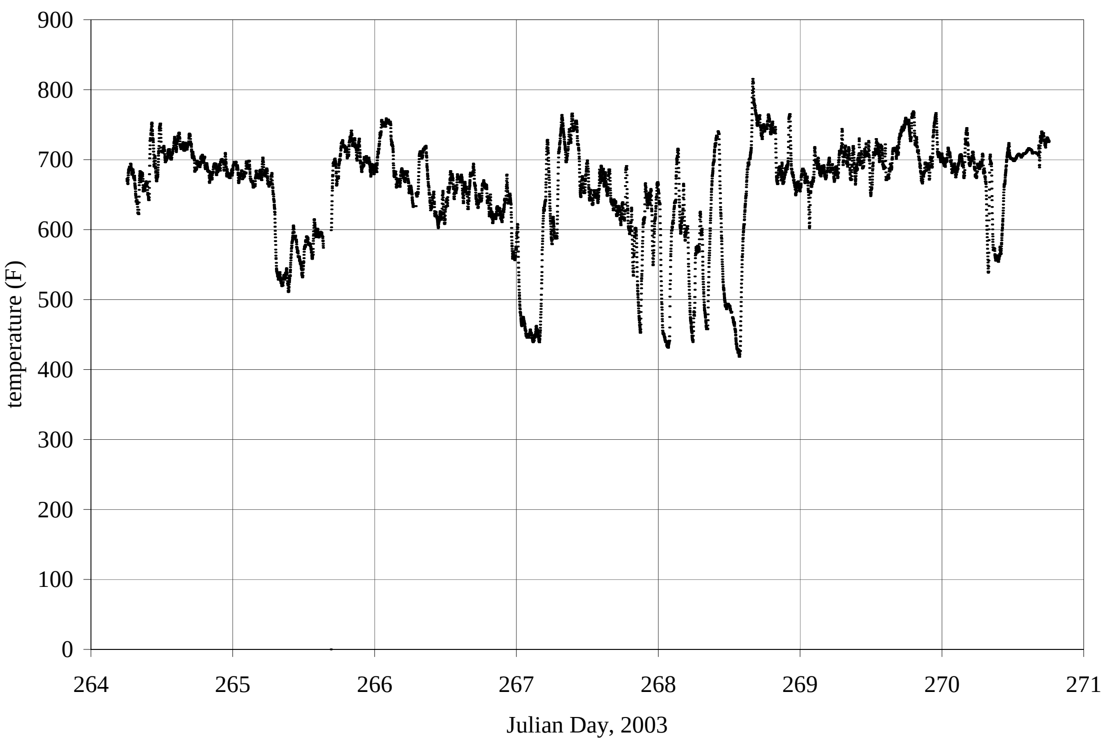


Figure D52. Grate temperature at thermocouple #4, Boiler 3. Julian Day 264 = September 21, 2003.

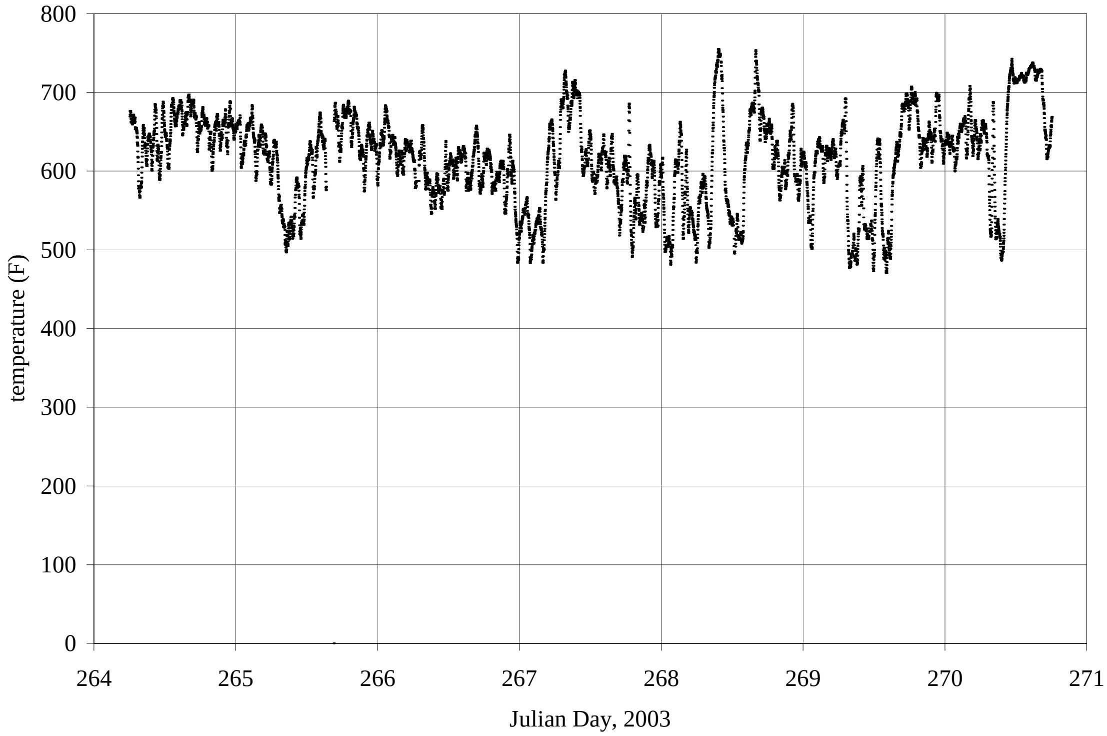


Figure D53. Grate temperature at thermocouple #5, Boiler 3. Julian Day 264 = September 21, 2003.

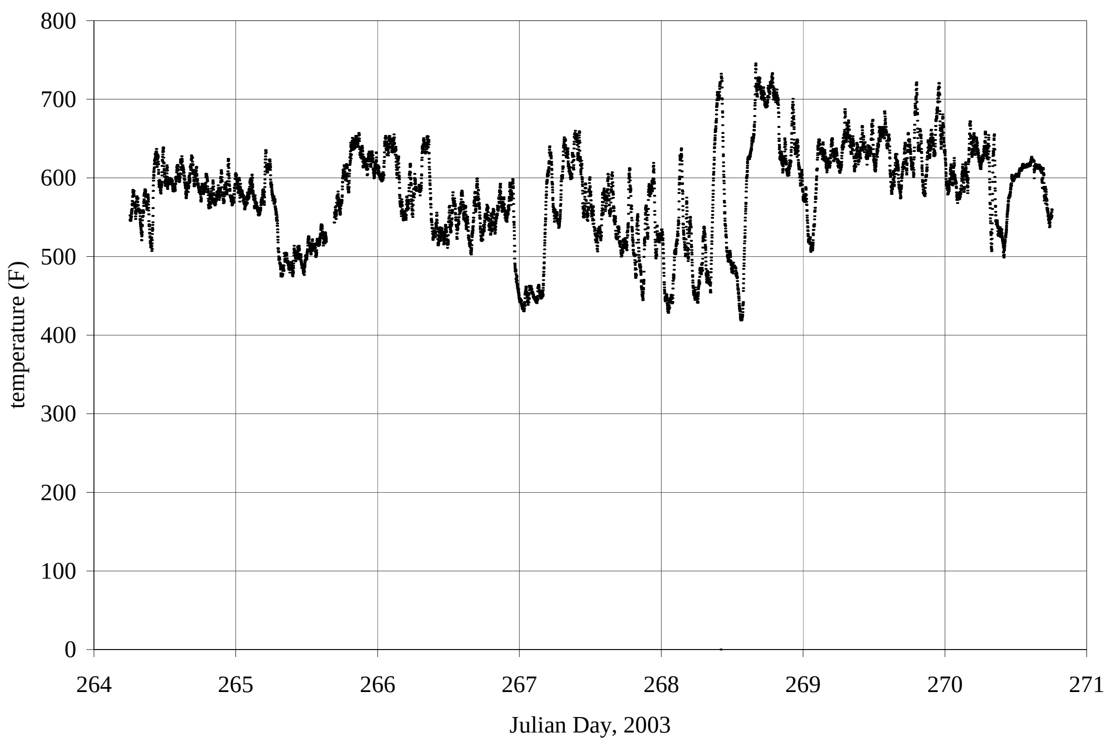


Figure D54. Grate temperature at thermocouple #6, Boiler 3. Julian Day 264 = September 21, 2003.

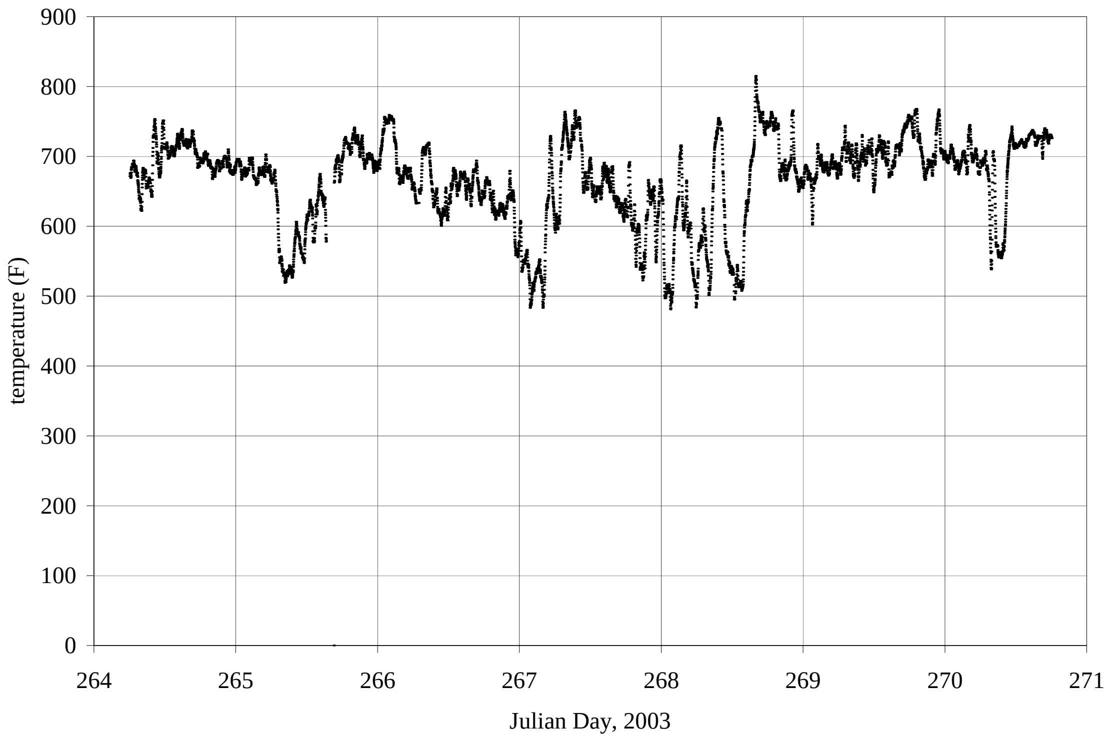


Figure D55. Air heater right bypass temperature, Boiler 3. Julian Day 264 = September 21, 2003.

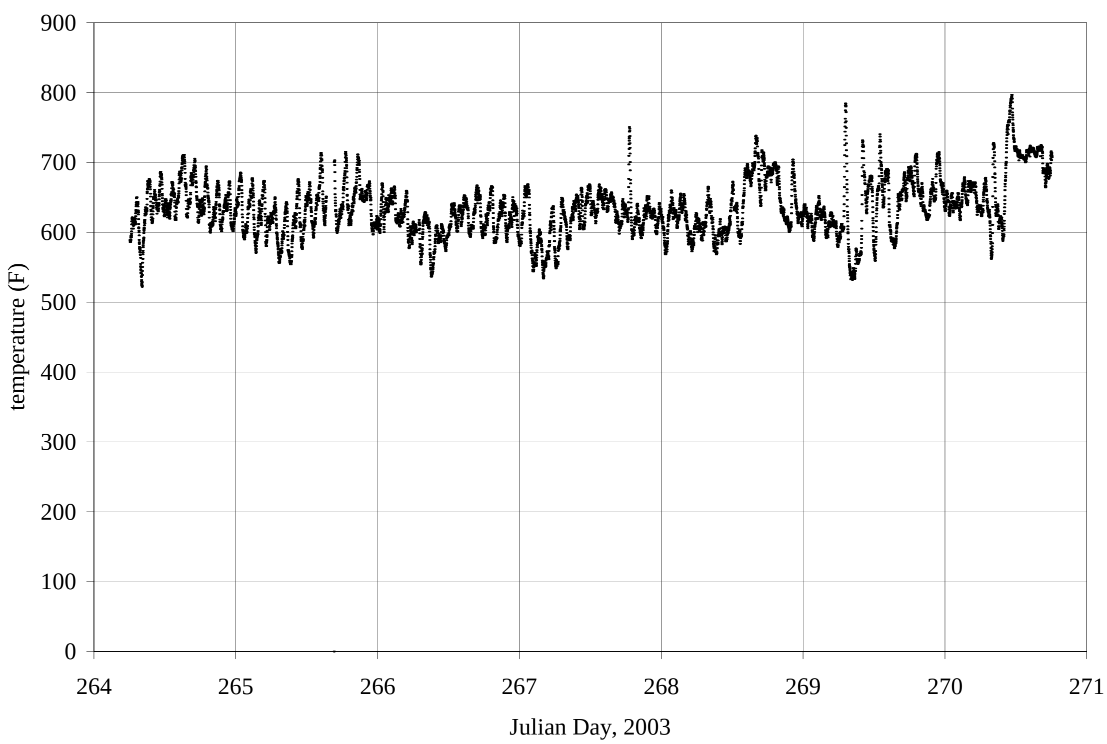


Figure D56. Air heater left bypass temperature, Boiler 3. Julian Day 264 = September 21, 2003..

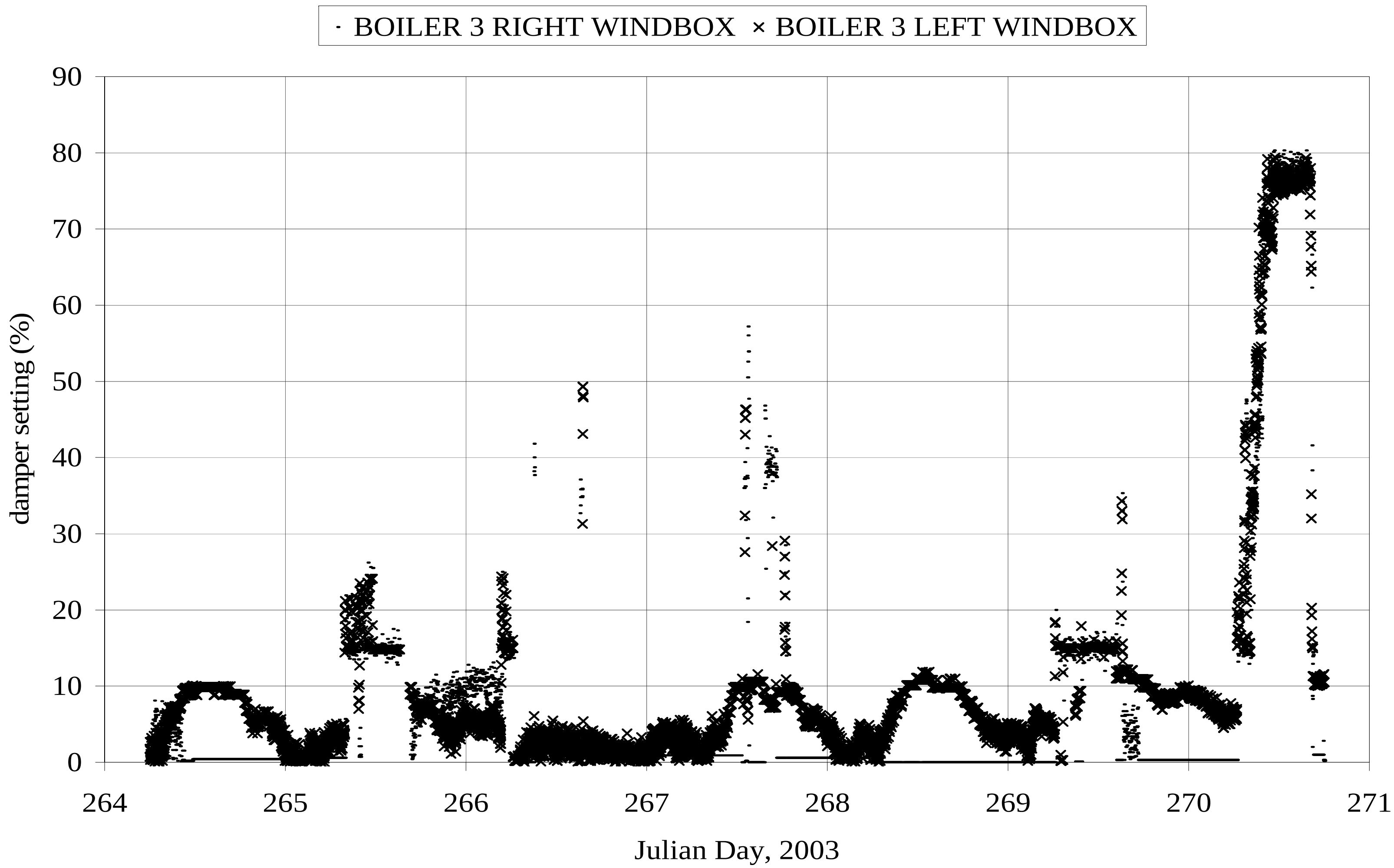


Figure D58. Air flow rates in left and right windbox, Boiler 3. Julian Day 264 = September 21, 2003.

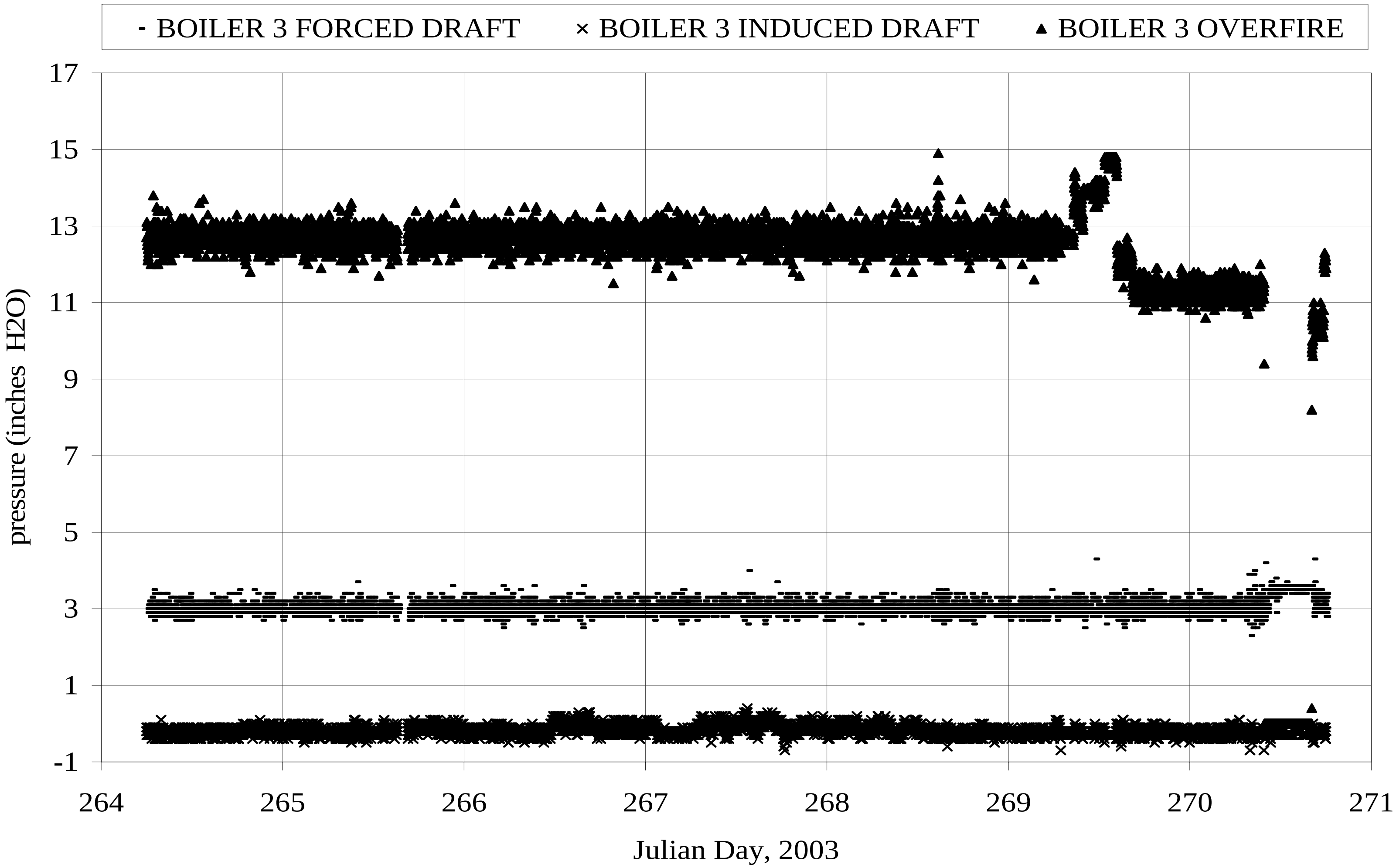


Figure D59. Forced draft, induced draft and overfire air pressure, Boiler 3. Julian Day 264 = September 21, 2003.

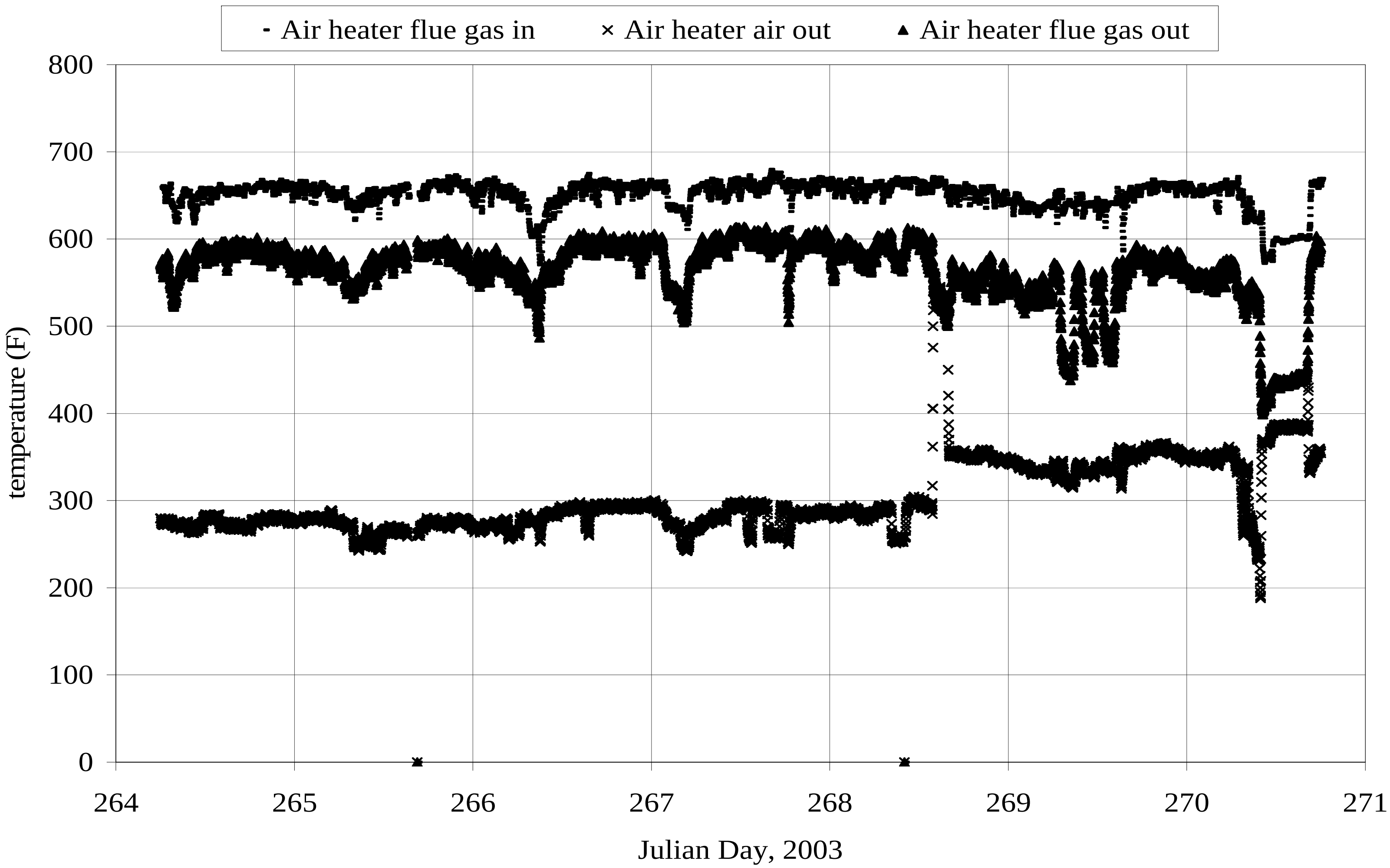


Figure D60. Air heater, flue gas in, flue gas out and air out temperature, Boiler 3. Julian Day 264 = September 21, 2003.

Integrated Sugar Factory Steam System Evaluation
Task 2 Deliverable Report

September 2005

HAWAII NATURAL ENERGY INSTITUTE
School of Ocean and Earth Sciences and Technology
University of Hawaii at Manoa

Integrated Sugar Factory Steam System Evaluation
Task 2 Deliverable Report

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Contents

Abstract

Hawaii's largest sugar producer, Hawaiian Commercial & Sugar Co. (HC&S), has undertaken a plantation wide energy efficiency assessment with cost share from the U.S. Department of Energy's (DOE) Office of Industrial Technology (OIT). This assessment includes analyses of the irrigation pumping system, electrical distribution system, and sugar factory. University of Hawaii (UH) project participants developed a comprehensive model of the steam system in the HC&S sugar factory using Aspen Plus computer modeling software in order to conduct investigations into steam use. A pinch analysis was conducted to guide an investigation into energy saving modifications to factory equipment and operations.

The HC&S sugar factory at Puunene is a modern and efficient facility with electrical power generation of approximately 80 to 85 kWh/ton of cane (tc) during periods of steady operation. While this range is high compared to sugar producers in other parts of the world where levels of 10-30 kWh/tc or less are common, levels of 90-100+ kWh/tc are thought to be attainable. Steam consumption for evaporating sugarcane juice and boiling sugar at HC&S is in the range of 800-850 lbs steam/ tc. Experts feel that the most efficient factories should be able to operate on 650 lbs steam/tc or less. Pinch analysis and Aspen Plus modeling software were used to investigate modifications that might reduce the factory steam-to-cane ratio and increase electricity export at HC&S.

Simulation results for five scenarios were discussed with HC&S personnel to determine feasibility based on operating constraints. Although simulation results for all five scenarios showed notable savings over the base case, only two of the five proposed changes were deemed possible within the operational constraints of the factory. Results from all five simulations were included for reference should conditions become more favorable for their implementation.

The two scenarios deemed possible within operating constraints were (1) operating the pan boiling system on second vapor rather than first vapor, and (2) adding the capability to flash condensates from evaporators 2, 3, and 4. Model results for using second vapor to supply pan boiling demands show a reduction in exhaust steam demand of about 21,000 pounds per hour which corresponds to a 65 lb/tc reduction in steam:cane ratio. If this steam was condensed in an existing turbo-generator at HC&S (TG4) it would increase electrical power generation by 0.95 MW. The model shows a decrease of nearly 6% for heat exchange surface area required in the evaporator train, offset by a 10% increase in required heat exchange surface area for the pans.

Modeling results for adding the capability to flash condensates from evaporators 3 and 4 show a potential steam savings equivalent to 8,000 pounds of exhaust steam which corresponds to a 25 lb/tc reduction in steam:cane ratio. Condensing this steam in TG4 would increase electrical power generation by approximately 0.36 MW. Model results indicate a net increase of less than half a percent in evaporator heat exchange surface area. Heat exchange surface area would need to be increased in the first three effects and reduced in the fourth and fifth effects. A negative consequence of this modification is an

increase in evaporator train condenser load, which would require increased cooling water supply and pumping capacity.

The combined modifications to the operation and equipment at HC&S Puunene sugar factory could decrease the steam:cane ratio by 12%. If the steam saved were converted to electricity present electricity export could be increased by 11%.

Introduction

Hawaii's largest sugar producer, Hawaiian Commercial & Sugar Co. (HC&S), has undertaken a plantation wide energy efficiency assessment with cost share from the U.S. Department of Energy's (DOE) Office of Industrial Technology (OIT). This assessment includes analyses of the irrigation pumping system, electrical distribution system, and sugar factory. The sugar factory assessment includes a steam generation efficiency assessment for the power plant and a steam utilization assessment of the factory including the mill, processing plant, and cogeneration plant. The University of Hawaii (UH) was contracted to provide technical assistance on these latter two tasks. This report summarizes work completed by UH on the steam utilization portion of the factory assessment.

Sugar cane processing yields three primary product streams; raw sugar, molasses, and bagasse. Raw sugar is sold as turbinado and to refiners while molasses is marketed as cattle feed supplement. Bagasse, the fibrous byproduct that remains after cane has been milled, is used as fuel in boilers to produce steam for electricity generation and factory processes. HC&S produces electricity in excess of their in-house demand, allowing them to export electricity to the utility grid.

Bagasse is a renewable energy resource and power generated from bagasse is considered to be nominally greenhouse-gas neutral. Utilization of a renewable energy resource for power generation helps reduce Hawaii's dependence on imported oil, enhances the local economy, and has environmental benefits. Electricity sold to the local utility helps the utility company meet renewable portfolio standards that have been targeted by the State of Hawaii. Environmental benefits, rising energy costs, and a highly competitive sugar market encourage maximization of electricity export.

Exportable electricity can be increased in two ways; bagasse can be converted into steam (and subsequently electricity) more efficiently, or, steam and electricity use in the sugar factory can be reduced, thus increasing the amount of exportable power. An index of sugar factory electricity generation is commonly reported in terms of kWh per ton of cane (tc) processed. This index is affected by both steam generation efficiency and steam use efficiency in the factory. Steam use efficiency is often reported as steam:cane ratio and has units of lb steam/tc. A typical value of steam:cane ratio for sugar factories world wide is 1000 lb/tc [1,2]. A value of steam:cane ratio under 1000 lb/tc is obtained by employing steam saving measures.

During periods of steady operation, HC&S's Puunene sugar factory generates about 80-85 kWh per ton cane processed. While this number is high when compared with cane sugar producers from other parts of the world, some room for improvement exists. Maximum attainable electricity generation from an efficient sugar factory running at full capacity is in the range of 90 to 100+ kWh/tc processed [2]. Steam consumed in cane processing at HC&S is in the range of 800-850 lb/tc. While HC&S's steam:cane ratio is well below average accepted levels it does not yet approach minimum values. Experts feel that the most efficient factories should be able to operate on 650 lbs steam/tc or less [3].

HC&S's Puunene sugar factory currently employs most of the conventional steam saving measures found in the cane sugar industry and has been an industry leader in cogeneration. As such, examining the factory configuration and operating conditions of other sugar producers for areas of potential efficiency gains was not of great interest. Instead, computer analysis techniques were used to evaluate the steam use efficiency and how proposed modifications to the factory would impact steam requirements.

Sugar factories are complex operations, but advances in process modeling software now make it possible to generate accurate working models. If sufficient input parameters are provided, these models can be used to assess the entire process and identify areas where improvements might be feasible. Proposed process and operational modifications can be modeled to quantify improvements and identify potential impacts on the larger system. Results from these models combined with operator input and company goals can then be used to make decisions on plant upgrades.

The initial evaluation of HC&S's Puunene sugar factory was accomplished using the Advanced System for Process ENgineering (ASPEN) PLUS® commercial software package from Aspen Technology Inc. (Cambridge, MA). Further analysis was carried out using a pinch analysis program, Aspen Pinch. Five areas where operational or equipment modifications could lead to more efficient use of process steam were identified. After consultation with HC&S personnel, only two of the proposed modifications were found to function within operational constraints imposed by the existing sugar factory. The details of the modeling effort and results are presented in the remainder of this report.

Description of Sugar Factory

The HC&S sugar factory was originally constructed in 1901. Over the last century improvements and modifications have occurred at regular intervals. In 1957, HC&S installed, what was then, the largest bagasse-fired boiler system in the world. This boiler system remains in place today but has been updated and augmented with a third boiler that was commissioned in 1977. In the late 1980's the entire factory was computerized, making it one of the first sugar factories to do so. Today, HC&S continues to innovate and update its factory and processing facilities [4].

Over the last 20 years the number of sugar plantations in Hawaii has declined dramatically as a result of increased competition from lower cost producers in other nations. Today, sugar is grown at two remaining plantations on Maui and Kauai, HC&S and Gay & Robinson (G&R), respectively. Throughout the state-wide decline of the sugar industry, HC&S has upgraded and modified its Puunene factory to increase capacity as other mills have closed. Today it processes about 1.6 million tons of net cane annually, producing over 200,000 tons of raw sugar and more than 70,000 tons of molasses [5].

The layout of the Puunene factory can be most easily described by breaking it into three main processes, steam generation, cane milling and juice boiling. Flow sheets depicting the three main process areas are presented in the Appendix.

In the power plant, steam is produced by burning sugarcane bagasse and/or coal in three generating units (Boiler 1, Boiler 2, and Boiler 3) and then fed to two turbo generators, TG4 and TG5. The boilers are all spreader stokers equipped with traveling grates. Boilers 1 and 2 were purchased from Riley Stoker Corporation and are identical, with rated capacities of 125,000 lb steam/hr and 900 psig steam pressure. Flue gases from the two units are exhausted through a common wet scrubber and stack. Residue from their grates enters a common water quench and is removed by belt conveyor. Boiler 3 was purchased from Foster Wheeler, operates at 425 psig steam pressure, and is rated for 350,000 lb steam/hr. Flue gas from Boiler 3 is exhausted through a dedicated wet scrubber and stack and the grate residue is also removed using a water quench and conveyor system

Electricity is generated using two extraction condensing turbines, TG4 and TG5. TG5 operates on 900 psig steam and has a maximum continuous rating of 200,000 lb steam/hr. The extraction pressure for TG5 is 425 psig. TG4 operates on 425 psig steam, has a maximum continuous rating of 400,000 lb/hr, and steam is extracted at a pressure of 15 psig.

The mill line separates cane stalks into juice and fiber through a process of shredding and crushing. Cane from the fields is washed to clean off soil residues and then undergoes several particle size reductions before being crushed to expel the juice. The mill line at HC&S has a 5,000 hp, steam-driven Walkers shredder with 96 hammers. The shredder is followed by four, 1,000 hp, steam-driven, six roll, light duty mills equipped with pressure feeders. The first mill has inlet dimensions of 84" x 43" with the subsequent mills having dimensions of 78" x 43". Turbines power the shredder and the mills; the shredder runs on 900 psig steam while the mills operate using 425 psig steam. An electric driven, 750 hp knife-set running at 880 rpm precedes the shredder.

In the boiling house, juice from the milling process is concentrated into a thick syrup before undergoing crystallization and separation that results in two product streams, molasses and raw sugar. The boiling house at HC&S employs three mixed juice heaters, a clarified juice heater, a quintuple effect evaporation train, and a pan evaporation set operating on the B magma boiling system. The quintuple effect evaporator train includes three first effect evaporators operating in series on exhaust (15 psig) steam followed by second, third, fourth and fifth effect evaporators, each running on vapor from the previous effect. The combined heat exchange surface area of all seven evaporators is 155,900 square feet. The juice heaters have a total heat exchange surface area of 21,800 square feet and operate using exhaust steam. The first and second mixed juice heaters operate on second and third vapor respectively, while the tertiary mixed juice heater and clarified juice heater operate on first vapor.

The evaporator pan system includes A and C continuous pans and batch pans for B magma, B seed, low grade seed, and food grade sugar. Total evaporator pan heat exchange surface area is 49,400 square feet. The A and C continuous pans each have a heat exchange surface area of 10,342 square feet. The seed pans have heat exchange surface areas of 4,283 and 5,270 square feet for B seed and low grade seed, respectively. B magma batch pans have a combined heat exchange surface area of 9,000 square feet and the food grade pans have a combined area of 10,162 square feet. During periods of maximum utilization the A continuous pan is augmented with a pair of 4,061 square foot batch pans.

Modeling

The first step in assessing steam utilization at HC&S's Puunene sugar factory was to develop a base model using the Aspen Plus computer simulation software. Since Aspen plus is primarily used in the petrochemical industry it does not include many of the unit operations found in a sugar factory, however it is flexible enough that equivalent substitutes can be developed based on existing unit operation models. The Aspen Plus solution algorithm assumes continuous, steady state processes. It should be emphasized that modeling is carried out only for continuous operations. Scenarios involving process interruptions, pan and evaporator steam outs, and scheduled down time cannot be accounted for in the Aspen models.

Establishing the factory layout and creating a preliminary flow sheet were necessary precursors to developing a working model. Working with HC&S personnel an outline of the factory flow sheet was developed. Difficulty was encountered while trying to establish pan boiling system parameters. Portions of the pan boiling system operate using batch processing, and recycling and reboiling are utilized but are not explicitly measured. Dilution and reprocessing further complicate the process. Modifications to operating parameters occur in real time and from batch to batch making it a challenge to arrive at a set of representative operating parameters.

The black box nature of the pan boiling system necessitated making gross assumptions in the pan portion of the Aspen model. Using known inlet and outlet flows and input from HC&S personnel, a rough but workable model was developed for the pan boiling section of the factory. Following the completion of the flow sheet, input for operating parameters was gathered. Establishing a representative set of operating parameters involved examination of data logs, onsite measurements, and extensive discussion with factory personnel.

In cases where required inputs could not be measured, estimates or calculated values were used. When calculation or estimation was not easily accomplished, average values were obtained from the literature. Estimated and calculated parameters included heat transfer coefficients in heaters evaporators and pans, vapor bleeding to pans and mixed juice heaters, massecuite and pan input flows, pressure losses, and thermal losses.

Arriving at a representative set of values was also complicated by the vagaries of sugar processing. Variations in weather, field conditions, cane quality, milling throughput, boiler operation, evaporator performance, heat exchanger fouling, hydroelectric availability, and water treatment can influence the cane processing rate and boiling house efficiency. Arriving at a model that would simulate periods of high capacity operation (<90%) required careful study of the factory operation. After extensive consultation with HC&S personnel a representative set of base case operating parameters was established as shown in Table 1.

Initial model runs were completed using the operating parameters shown in Table 1. Wonderware data for the factory that were logged during boiler efficiency testing in September, 2003, were used for model verification. Further adjustments were made to optimize the model before investigating equipment and process changes. Areas of potential process change were identified with the help of pinch analysis.

Pinch Analysis

Pinch analysis is a tool for examining energy supply and demand balances in complex processes. Pinch analysis was developed in the early 1980's as a method to simplify the design of energy recovery systems. Since that time the technology has matured and a number of computer programs have been developed to enhance its application and ease of use. Despite these advances, pinch analysis has not been widely employed outside of a narrow group of industrial sectors, most notably petroleum refining and more recently steel and paper manufacturing. Raw sugar manufacturing from cane is an area where pinch technology has had limited penetration. Some examples of its application have been published, but raw sugar manufacture from cane largely remains a new application for pinch analysis [6].

Pinch analysis provides a systematic method for analyzing process energy demands using the first and second laws of thermodynamics. The first step in pinch analysis is to identify and quantify all process streams that undergo temperature changes. Process streams that require heating are listed as “cold streams” and streams that require cooling are listed as “hot streams.” Values of specific heat, supply temperature, target temperature, and mass flow rate are tabulated for all hot and cold streams.

The next step is to display the tabulated process stream data graphically. It is useful to define a heat capacity flow rate (CP) as the product of flow rate in lb/sec and specific heat in BTU/lb °F. This new value, CP, with units of BTU/sec °F can be used to easily graph enthalpy change in process streams. Temperature is plotted against enthalpy in plots called composite curves. The process composite curve contains both hot and cold composite curves.

In the process composite curve, the hot curve appears above the cold curve. In most processes, the variation in CP values for different streams results in kinked composite curves as depicted in Figure 1. The smallest vertical distance between the hot and cold curves is called the minimum temperature approach (DTmin). This point represents a bottleneck in heat recovery and is also referred to as the pinch point or pinch temperature. The DTmin value can be adjusted, shifting the curves farther apart, leading to lower process-to-process heat exchange and higher utility requirements. For a given DTmin, minimum hot and cold utility requirements can be determined and are indicated by the extent to which the hot and cold ends of the composite curve do not overlap.

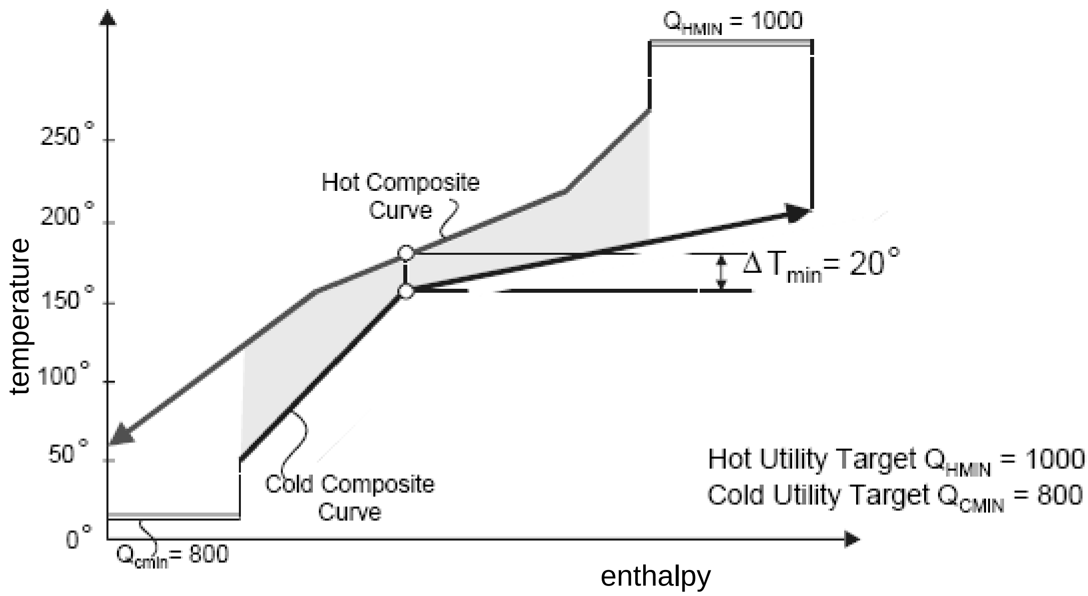

Figure 1. Example of a process composite curve generated with Aspen pinch showing hot and cold composite curves.

Using the process composite curve, minimum energy requirements can be determined and modifications to the process heat exchange network can be developed. Various programming tools are available to aid in heat exchange network design and process modification decisions. Additional information on pinch analysis and pinch techniques is available in numerous references [7,8,9].

One of the reasons pinch analysis has not been widely adopted in the cane sugar industry is the unique thermal energy use profile of sugar factories. Industries in which pinch analysis is commonly applied involve heating and cooling of process streams over a range of temperatures. Sugar processing, on the other hand, involves primarily the evaporation of large quantities of water and has few if any high temperature product streams that require cooling. The temperature composite curve for a typical sugar factory shows limited opportunity for modifying heat exchange networks to improve efficiency.

Table1. Base case operating parameters for HC&S Puunene sugar factory.

Factory Parameter	Units	Value	Factory Parameter	Units	Value
Mixed Juice Flow	lb/hr	800,000[b]	3rd Vapor Bleed to MJH1	lb/hr	13,500[b]
Mixed Juice Brix	brix	14.4[a]	Syrup Brix	brix	65[b]
Mixed Juice Purity		86.72[a]	Apan Feed Brix	brix	70[b]
Mixed Juice Inlet Temperature	F	110[b]	Apan Feed	lb/hr	200,250[c]
First Mixed Juice Heater Outlet Temperature	F	168[b]	Asugar Yield	%	54.82[a]
Second Mixed Juice Heater Outlet Temperature	F	187[b]	Amassecuite Brix	brix	91.2[a]
Third Mixed Juice Heater Outlet Temperature	F	214[b]	Bpan Feed Brix	brix	70[b]
Clarified Juice Heater Inlet Temperature	F	200[b]	Bpan Feed	lb/hr	100,515[c]
Clarified Juice Heater Outlet Temperature	F	221[b]	Bsugar Yield	%	43.5[a]
Evaporator 1A Inlet Steam Pressure	psia	21.7[b]	Bmassecuite Brix	brix	92.9[a]
Evaporator 1A Inlet Steam Temperature	F	268[b]	Cpan Feed Brix	brix	70[b]
Evaporator 1A Operating Pressure	psia	19.5[b]	Cpan Feed	lb/hr	66,062[c]
Evaporator 1B Inlet Steam Pressure	psia	24.6[b]	Cmassecuite Brix	brix	
Evaporator 1B Inlet Steam Temperature	F	268[b]	Seedpan Feed Brix	brix	70[b]
Evaporator 1B Operating Pressure	psia	19.5[b]	Seedpan Feed	lb/hr	66,062[c]
Evaporator 1C Inlet Steam Pressure	psia	26.4[b]	Seedmassecuite Brix	brix	
Evaporator 1C Inlet Steam Temperature	F	268[b]	FGpan Feed Brix	brix	70[b]
Evaporator 1C Operating Pressure	psia	19.5[b]	Fgpan Feed	lb/hr	66,062[c]
Evaporator 2 Inlet Steam Pressure	psia	19.5[b]	FGsugar Yield	%	
Evaporator 2 Inlet Steam Temperature	F	227[b]	Fgmassecuite Brix	brix	
Evaporator 2 Operating Pressure	psia	13[b]	Molasses Yield	lb/hr	
Evaporator 3 Inlet Steam Pressure	psia	13[b]	Apan Heat Exchange Surface Area	ft^2	10,342[b]
Evaporator 3 Inlet Steam Temperature	F	214[b]	Bpan Heat Exchange Surface Area	ft^2	9,000[b]
Evaporator 3 Operating Pressure	psia	8.8[b]	Cpan Heat Exchange Surface Area	ft^2	10,342[b]
Evaporator 4 Inlet Steam Pressure	psia	8.8[b]	Seedpan Heat Exchange Surface Area	ft^2	9,554[b]
Evaporator 4 Inlet Steam Temperature	F	187[b]	FGpan Heat Exchange Surface Area	ft^2	10,162[b]
Evaporator 4 Operating Pressure	psia	5[b]	Pan Operating Pressure	psia	2.2[b]
Evaporator 5 Inlet Steam Pressure	psia	5[b]	900psia Steam Flow	lb/hr	200,000[b]
Evaporator 5 Inlet Steam Temperature	F	165[b]	425psia Steam Flow	lb/hr	400,000[b]
Evaporator 5 Operating Pressure	psia	2.2[b]	30psia Steam Flow	lb/hr	260,000[b]
1st Vapor Bleed to Pans	lb/hr	117,000[b]	900psia Steam to Shredder	lb/hr	39,500[b]
1st Vapor Bleed to MJH3	lb/hr		425psia Steam to Mills	lb/hr	55,000[b]
1st Vapor Bleed to CJH	lb/hr		425/30 PRV Flow	lb/hr	12,000[b]
2nd Vapor Bleed to Cpan	lb/hr		425/150 PRV Flow	lb/hr	15,000[b]
2nd Vapor Bleed to MJH2	lb/hr		Clarifier Tank Temperature Loss	F	-14[b]
a=Factory Report b= HC&S c=Calculated					

The limitations of pinch analysis for sugar factories are discussed by Thompson of Sugar Technologies International LTD [9]. Opportunities for heat recovery in sugar factories are limited to streams below the pinch temperature as no hot streams requiring cooling exist above the pinch. One of the opportunities for heat recovery below the pinch is preheating boiler air and boiler feed water with exhaust vapor or condensate. These heat recovery methods are rarely used as they are often uneconomical and/or difficult to implement.

Pinch analysis also identifies latent heat loads placed on the utility steam as an opportunity for energy savings. In the case of a sugar factory, this involves reducing the amount of water evaporated in the lower efficiency evaporation pans. This can be accomplished by increasing the inlet brix concentration, resulting in more water being evaporated in the preceding, highly efficient, multiple-effect evaporator train. Reducing the amount of additional water that is added during pan processing can also reduce heating loads. Operating at higher brix levels requires high purity juice which is mostly a function of field conditions and to a lesser extent, milling operations. While it is theoretically possible to operate at higher concentrations, 70-73 brix rather than 65 brix, the potential operational difficulties that could result from running at these levels may outweigh gains.

Continuous operation at elevated brix is extremely difficult to maintain. Fluctuation in purity levels force operators to work with a margin of safety during batch operations to avoid problems with false graining, conglomeration, inversion, and coloring. Within the current processing parameters, pan operations are conducted at brix levels that facilitate smooth operation and maintain a sufficient margin of error for unexpected process fluctuations. While operating at higher levels has been reported elsewhere, especially in the beet sugar industry, the feasibility of operating at these elevated levels must be confirmed in practice. Modeling showing potential gains resulting from operating at higher brix is discussed in the results section of this report.

The final area that pinch can be useful is in guiding evaporator configuration and process steam distribution. Quintuple effect evaporation trains such as the one utilized at HC&S are highly efficient and do not lend themselves to analysis using pinch. Literature on pinch analysis for multiple effect evaporation systems suggests a decomposition approach that involves separating the evaporators from the process heating network. Matching the utility loads to the vapor streams in the evaporator train is then carried out to maximize efficiency. Employing this technique led to the identification of several areas where modifications could result in more efficient use of process steam [9,10,11].

Results and Discussion

Scenarios identified in the pinch analysis were investigated using the Aspen Plus model. Results from runs of modified cases were compared against the base case and changes in steam demand, heat exchange surface areas and steam flows were noted. Where savings were realized, it was assumed that any increase in available steam (resulting from a decrease in steam demand) would be used to generate electricity for export. This may not always be the best choice, as increasing processing throughput or utilizing electricity to provide additional power to pump irrigation water might yield better economic returns depending on market conditions.

Second Evaporator Vapor to Pans

Scenario analysis began with examination of HC&S's evaporator train using the decomposition method. The first composite curve for utility loads, shown in Figure 2, was generated using Aspen Pinch. Unlike Figure 1, shown in the pinch analysis section, Figure 2 shows the unique energy use profile of a sugar factory. Note that no hot streams exist above the pinch point to provide heating. All the process heating above the pinch temperature must be provided by hot utility streams, in HC&S's case, bled vapor from the evaporator train.

Temperature levels of the vapors available from the evaporation train in its current configuration were overlaid to produce Figure 3. As shown in the figure, nearly half of the utility heating demand is consumed in the pans. While some steam is used to raise the temperature of the syrup, the majority of the energy demand in the pans is for water evaporation, thus the long plateau at 152ºF, the vaporization temperature of water at 25.5 inches of mercury vacuum. In the base case model, the evaporation pans are operated primarily with first vapor, the exception being the Cseed continuous pan which operates on second vapor.

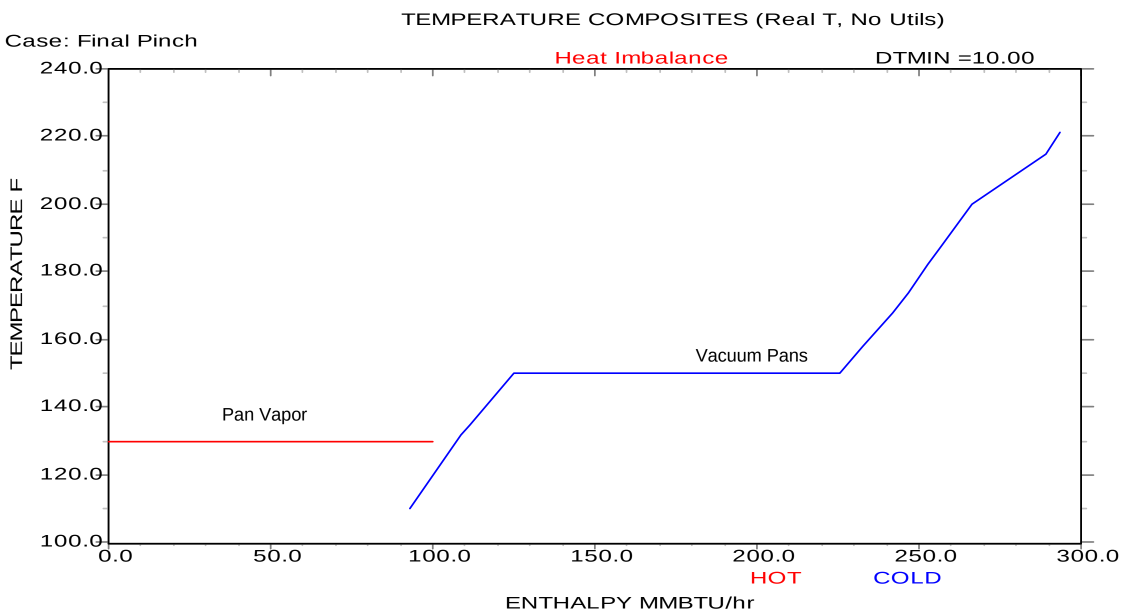

Figure 2. Composite curve for utilities at HC&S Puunene sugar factory.

Looking at Figure 3, it appears that the 70ºF temperature difference between first vapor and the temperature needed to evaporate water at 25.5 inches of mercury vacuum is much greater than necessary; however operational constraints reduce the available portion of this difference substantially. The syrup is boiled in large calandria pans and a boiling point rise in the range of 20-30ºF is observed. Furthermore, the required temperature approach in shell and tube heater exchangers typically ranges from 10-20ºF. This gives a required temperature difference between the steam and the syrup of 30-50ºF and it would appear that this could be satisfied using second vapor (210ºF - 152ºF = 58ºF), thereby reducing the demand for first vapor. This opportunity was investigated and modeled in Aspen. Results show that using second vapor to meet pan boiling demands would reduce exhaust steam demand by about 21,000 pounds per hour which corresponds to a 65 lb/tc reduction in steam:cane ratio. If this steam were condensed in TG4 it would produce 0.95 MW of additional electricity.

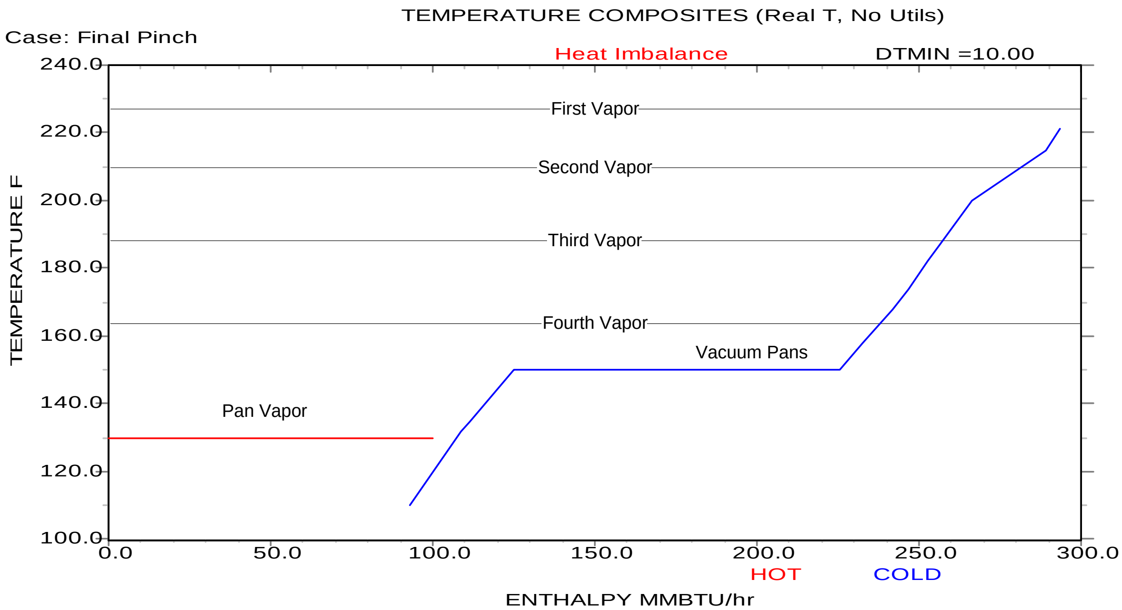

Figure 3. Composite curve for utilities at HC&S Puunene sugar factory with pan outlet vapor temperature overlay.

Using second vapor would require heat exchange surface area modification in both the pans and the evaporators. Modeling shows a reduction in required heat exchange area for the first effect of the evaporation train with a corresponding increase in area for the second effect. Some reduction is also seen in the third, fourth, and fifth effects. Overall, the model results show the total heat exchange area required for the evaporation train would decrease by almost 6% and that the pan heat exchange surface area would need to be increased by approximately 10%. Model results for heat exchanger specifications can be found in Table 2 and 3.

Piping for routing second vapor to the pans has been installed, but is currently unused, except in the case of the continuous C pan, where it provides second vapor for evaporation. Second vapor has been tested in the batch pans but resulted in slower heating rates and extended processing times. First vapor is favored under the current factory configuration because it allows operators to cycle the batch bans quickly. Replacing batch pans with continuous pans for B, seed, and food grade sugars, or adding heat exchange surface area to the present batch pans, would allow operators to maintain high cycle rates while utilizing second vapor.

Switching to continuous pans rather than increasing the surface area of the existing batch pans would help reduce the amount of additional surface area required to successfully operate the pans using second vapor. Capital costs and disruption to operations that would result from switching from batch to continuous pans would be significant. At present this modification may not represent an adequate return on investment, however the potential for significant energy savings warrants closer consideration.

Table 2. Evaporator heat exchanger specifications and model results.

Evaporator	Value	Base Case	2nd Vapor to Pans	3rd Vapor to Pans	Vapor to Mixed Juice Heaters	Flash Condensate	70 Brix Syrup	Units
1A	Area	32,910	30,256	27,305	31,795	31,994	31,994	ft^2
	U	113	113	113	113	113	113	Btu/hr-ft^2-°F
	Δ Area	0	-2,654	-5,605	-1,757	-1,115	-916	ft^2
1B	Area	21,084	19,372	17,471	19,951	20,363	20,494	ft^2
	U	240	240	240	240	240	240	Btu/hr-ft^2-°F
	Δ Area	0	-1,712	-3,613	-1,133	-721	-590	ft^2
1C	Area	11,806	10,648	9595	11,165	11,398	11,271	ft^2
	U	160	160	160	160	160	160	Btu/hr-ft^2-°F
	Δ Area	0	-1,158	-2,211	-641	-408	-535	ft^2
2	Area	24,689	48,424	42,150	26,424	22,493	25,931	ft^2
	U	315	315	315	315	315	315	Btu/hr-ft^2-°F
	Δ Area	0	23,735	17,461	1,735	-2,196	1,242	ft^2
3	Area	22,572	17,546	40,872	22,820	21,511	23,792	ft^2
	U	198	198	198	198	198	198	Btu/hr-ft^2-°F
	Δ Area	0	-5,026	18,300	248	-1,061	1,220	ft^2
4	Area	21,516	15,004	8,177	27,782	22,582	23,173	ft^2
	U	277	277	277	277	277	277	Btu/hr-ft^2-°F
	Δ Area	0	-6,512	-13,339	-6,266	1,066	1,769	ft^2
5	Δ Area	21,273	14,195	7,411	17,026	26,369	23,285	ft^2
		140	140	140	140	140	140	Btu/hr-ft^2-°F
	Area	0	-7,078	-13,862	-4,247	5,096	2,012	ft^2

Table 3. Pan heat exchanger specifications and model results.

Pan	Value	Base Case	2nd Vapor to Pans	3rd Vapor to Pans	70 Brix Syrup	Units
A	Area	10,348	11,391	15,041	8,174	ft^2
	U	87.5	87.5	87.5	87.5	Btu/hr-ft^2-°F
	Δ Area	0	1,043	4,693	-2,174	ft^2
B	Area	8,946	9,971	13,916	8,946	ft^2
	U	57	57	57	57	Btu/hr-ft^2-°F
	Δ Area	0	1,025	4,970	0	ft^2
C	Area	9,608	10,902	16,946	9,608	ft^2
	U	37	37	37	37	Btu/hr-ft^2-°F
	Δ Area	0	1294	7,338	0	ft^2
Seed	Area	10,379	10,379	15,778	10,379	ft^2
	U	37	37	37	37	Btu/hr-ft^2-°F
	Δ Area	0	0	5399	0	ft^2
Food Grade	Area	10,100	11,450	17,877	10,100	ft^2
	U	35	35	35	35	Btu/hr-ft^2-°F
	Δ Area	0	1,350	7,777	0	ft^2

Third Evaporator Vapor to Pans

The use of third vapor for pan boiling was also modeled, although HC&S personnel did not deem it to be a viable option due to operational/space constraints in the factory. Model results for using third vapor to drive pan boiling show additional savings over second vapor of 22,000 pounds of exhaust steam per hour which corresponds to a 69 lb/tc reduction in steam:cane ratio. If this steam were condensed in TG4 it would produce an additional 0.99 MW. The total increased electricity production gained by shifting from first vapor (base case) to third vapor would be 1.95 MW. The total reduction in steam:cane ratio would be 134 lb/tc.

Using third vapor in the boiling pans would require more extensive modification to heat exchange surface areas than shifting to second vapor. Model results show that use of third vapor could lead to a reduction in total heat exchange area of nearly 12% in the evaporators. Increases in surface area for the second and third effects would be offset by reductions in first, fourth and fifth effects. Operating the pans on third vapor would require replacement of all batch pans with continuous pans to facilitate heat transfer at lower temperature differences. Model results show required pan heat exchange surface area increasing by nearly 60%. Operating the boiling pans on third vapor would likely leave little room for error during the sensitive crystallization process. In addition, the infrastructure required to route low pressure third vapor steam to the pans in already tight factory space might require a major retrofit. Model results for heat exchanger area under this scenario are summarized in Tables 2 and 3.

Plate Type Mixed Juice Heaters

The third scenario investigated potential modifications to the mixed juice heaters. Once again, using steam from later evaporator effects can result in steam savings. HC&S employs shell and tube type, mixed juice heaters. This design operates reliably and rarely has fouling problems but requires higher approach temperatures than plate type exchangers. The lower temperature approach values allowable with plate heat exchangers would enable the mixed juice heaters at HC&S to be heated with lower temperature steam. Using plate heat exchangers, the first mixed juice heater could operate on fourth vapor, the second mixed juice heater on third vapor, and the third mixed juice heater and the clarified mixed juice heater could be shifted to second vapor. Modeling results for these modifications show an exhaust steam savings of 18,000 lbs/hr which corresponds to a 57 lb/tc reduction in steam:cane ratio. If this steam was condensed in TG4, electricity generation could increase by approximately 0.82 MW. The feasibility of adding plate heat exchangers is low however, because fouling problems and reduced reliability could outweigh potential energy gains. Model results for heat exchanger area under this scenario are summarized in Tables 2 and 4.

Increased Syrup Brix

As discussed in the pinch analysis section, raising the syrup brix level at the exit of the evaporators could reduce latent heat loads on the pans. Model evaluation of elevated brix shows reduced first vapor demand in the pans, however, operational difficulties that might ensue in the crystallization process cannot be fully represented in the model. Results show that an additional 2,900 pounds of exhaust steam would be required in the evaporators to increase syrup density to 70 brix. A syrup feed of 70 brix mixed with Bsugar remelt would produce an inlet brix of 73 brix to the A continuous vapor pan. Under these conditions first vapor demand in the A pan would decrease by 10,000 lbs/hr. This is equivalent to a reduction in exhaust steam demand of 8,000 lbs/hr. The net savings of exhaust steam from this modification would be about 5,000 lbs/hr which corresponds to a 16 lb/tc reduction in steam:cane ratio. Condensing this steam in TG4 would result in increased electricity generation of approximately 0.23 MW.

Table 4. Mixed juice heater heat exchanger specifications and model results.

Mixed Juice Heater	Value	Base Case	Vapor to Mixed Juice Heaters	Units
1	Area	4,612	8,641	ft^2
	U	190	190	Btu/hr-ft^2-°F
	Δ Area	0	4,029	ft^2
2	Area	6,771	16,839	ft^2
	U	63	63	Btu/hr-ft^2-°F
	Δ Area	0	10,068	ft^2
3	Area	5,154	9,030	ft^2
	U	165	165	Btu/hr-ft^2-°F
	Δ Area	0	3,876	ft^2
Clarified	Area	5,232	5,232	ft^2
	U	215	215	Btu/hr-ft^2-°F
	Δ Area	0	0	ft^2

Condensate Flash

Flashing condensate is a common steam saving method. At HC&S, flashing is carried out on first and second effect condensate. The feasibility of flashing all condensates to subsequent effects was investigated using the Aspen model. Model results show a potential steam savings equivalent to 8,000 pounds of exhaust steam which corresponds to a 25 lb/tc reduction in steam:cane ratio. Condensing this steam in TG4 would result in increased electricity generation of approximately 0.36 MW. This modification would result in small changes to the required heat exchange surface area in the evaporation train. Model results show a net increase of less than one-half percent with reductions in the first three effects and increases in the fourth and fifth. This modification would increase evaporator train condenser load, an unwanted side effect.

Summary and Conclusions

Pursuant to the plantation wide energy efficiency assessment project proposed for HC&S on Maui, UH project participants developed a comprehensive model of the HC&S sugar factory using Aspen Plus computer modeling software. A pinch analysis was conducted to guide investigation into energy saving modifications to factory equipment and operations.

The HC&S sugar factory at Puunene is a modern and efficient facility with electrical power generation of approximately 80 to 85 kWh/tc during periods of steady operation. While this range is high compared to sugar producers in other parts of the world where levels of 10-30 kWh/tc or less are common, levels of 90-100+ kWh/tc are believed to be attainable. Steam consumption for sugar boiling is in the range of 800-850 lb steam/tc. Experts believe that the most efficient factories should be able to operate on 650 lb steam/tc or less [3]. Pinch analysis and Aspen Plus modeling software were used to investigate modifications that might improve boiling house steam:cane ratio and electricity export at HC&S.

Simulation results for five scenarios were discussed with HC&S personnel to determine their feasibility. Although simulation results for all five scenarios showed notable savings over the base case, only two of the five proposed changes were deemed possible within the operational constraints of the factory.

The two scenarios deemed possible within operating constraints were (1) operating the pan boiling system on second vapor rather than first vapor, and (2) adding the capability to flash condensates from evaporators 3 and 4. Modeling the use of second vapor to supply pan boiling demands shows a reduction in exhaust steam demand of about 21,000 pounds per hour which corresponds to a 65 lb/tc reduction in steam:cane ratio. If this steam were condensed in TG4, it would increase electrical power generation by 0.95 MW. Using second vapor would require heat exchange surface area modification in both the pans and the evaporators. Overall, the model shows a decrease of nearly 6% for heat exchange surface area required in the evaporation train, offset by a 10% increase in required heat exchange surface area for the pans.

Modeling the addition of the capability to flash condensates from evaporators 3 and 4 shows a potential steam savings equivalent to 8,000 pounds of exhaust steam per hour, which corresponds to a 25 lb/tc reduction in steam:cane ratio. Condensing this steam in TG4 would increase electrical power generation by approximately 0.36 MW. Model results also indicate a net increase of less than 0.5% in required heat exchange surface area, with reductions in the first three effects offset by increases in the fourth and fifth effects. A negative consequence of this modification is an increase in evaporator train condenser load possibly offsetting some of the potential gain.

HC&S exports up to12 MW to the local utility. The 1.32 MW increase in electric generation from the combined effect of the above modifications would increase exportable electricity by nearly 11%. Steam:cane ratio would be reduced by about 12% from a range of 800-850 lb/tc to a range of 710-760 lb/tc.

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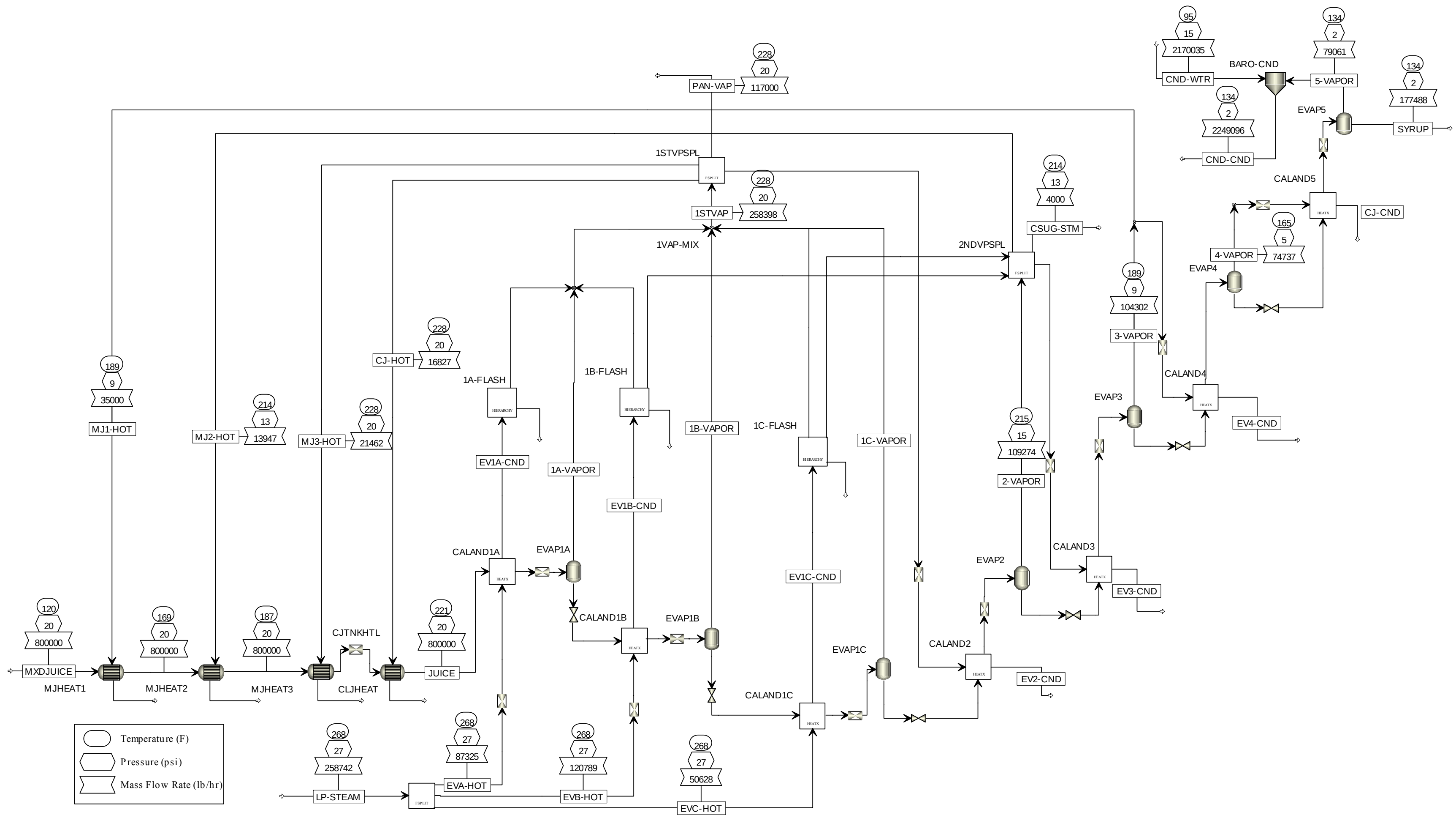
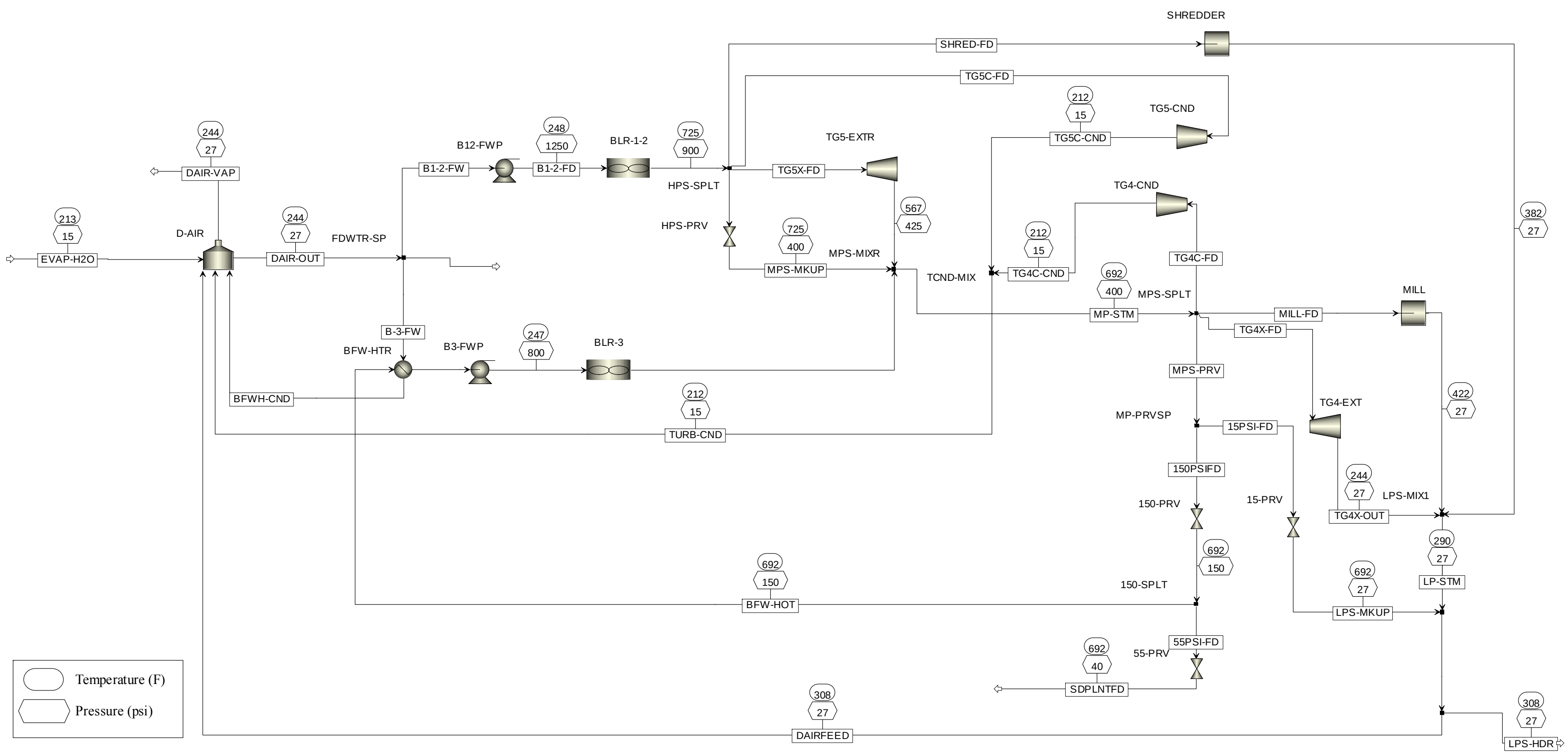
Appendix

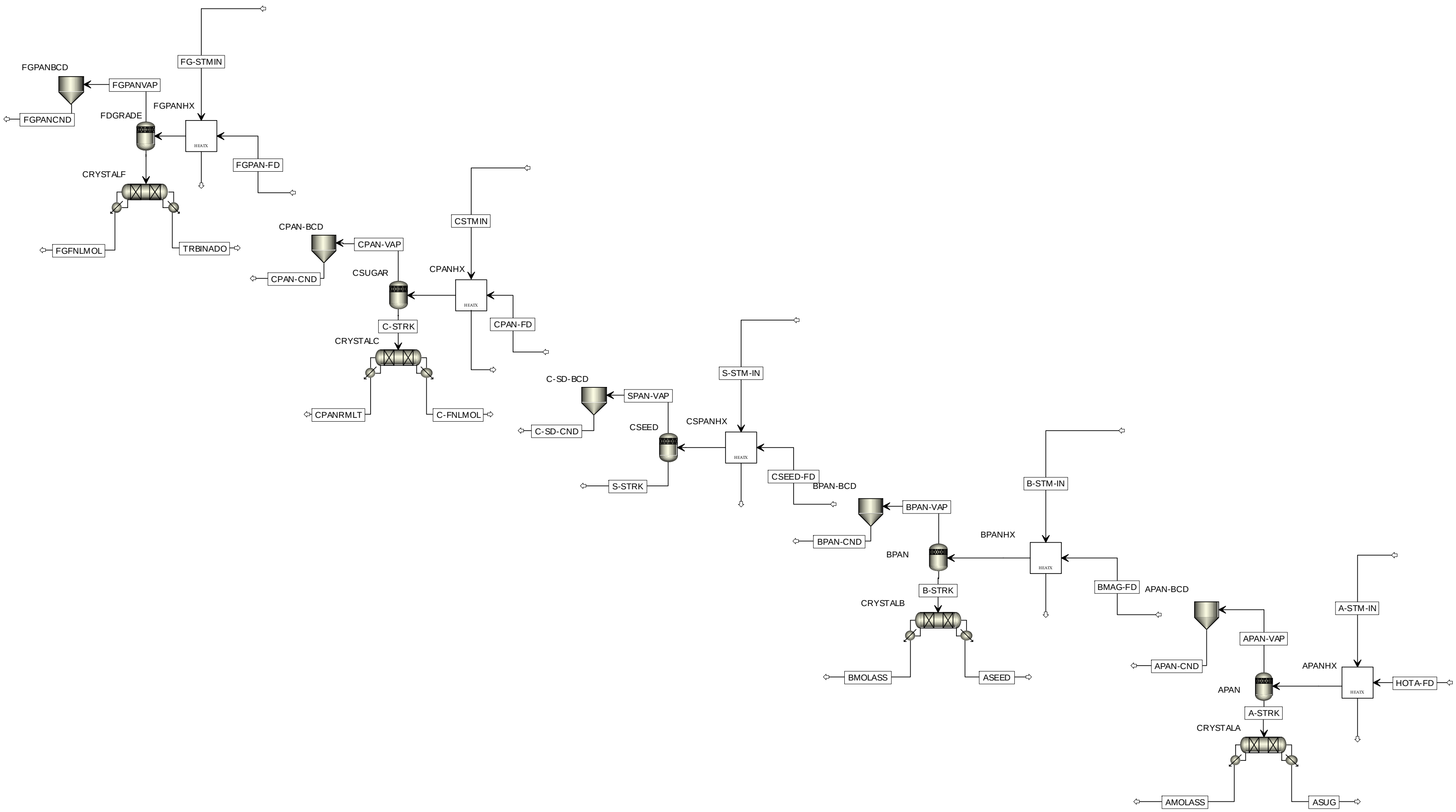
Aspen flow sheet for HC&S boiling house



Aspen flow sheet for HC&S power plant



Aspen flow sheet for HC&S pan boiling system



APPENDIX C

Steam Line Insulation Survey Results

Missing Insulation Survey
Puunene Power Plant

UNIT	LOCATION	DESCRIPTION	APPROX LINE TEMP.	ANNUAL HEAT LOSS - MMbtu
Boiler 3		450 # steam line - 14" dia. , missing 40’	750	4,537.6
	10th Floor	4" line, missing 20’ (off steam drum)	750	791.4
	9th Floor	4" line, missing 10’ (off steam drum)	750	395.7
	8th Floor - Steam Drum Level	18” line, missing 20’ – (two relief valves)	750	2,892.0
		1" line, missing 25’	750	348.7
		2" line, missing 5’	750	113.6
	7th Floor	2 ½” line, missing 10’	750	267.2
		¾” line, missing 25’	350	81.0
		2 ½” line, missing 5’	350	33.4
	6th Floor- South side	2 ½” line, missing 5’	750	133.6
		4" line, missing 5’	750	197.8
	5th Floor - Mud Drum Level	2" line, missing 150’	350	870.0
	4th Floor	2" line, missing 10’	350	58.0
		12" line, missing 5’	350	116.1
		2 ½ “ line, missing 15’	350	100.4
	@ Flash Tank	8" line, missing 5’	750	358.6
		3 ½” line, missing 20’ - includes 3rd floor for this line	350	173.2
		4" line, missing 20’ - into Boiler	750	791.4
	3rd Floor	4" line, missing 15’ vertical; 32’ horiz. - off flash tank	350	418.6
	2nd Floor	10" line, missing 6’ - near DA 3	750	529.0
		Misc. 2 ½“ lines, missing 300’ (est)	350	2,341.5
		Misc. 3 ½ lines, missing 200’ (est)	350	1732.0
		15" line, missing 20’	350	505.6

	1st Floor - Feed Pump Area	18" line, 20' horiz. –15' vert. (along TG 5 Building)	150	2,035
		10" line, missing 36' (non-continous)	350	716.8
		4" lines, missing 40' (to pumps)	530	794.8
		Misc. 1" lines, missing 150'	530	1,114.5
	Deareator tank	10" line, missing 10'	350	199.1
		4" line, missing 20'	350	152.4
		8" line, missing 15'	350	246.1
		2" line, missing 40'	350	232.0
		2 ½" line, missing 15'	350	100.4
	2nd Floor	Square 22" x 22" duct, missing 35'	1200	24,183.6
Boilers 1 & 2		8" line, missing 70' (900 # steam line - multiple locations)	750	5,019.7
	6th floor	2" line, missing 20'	750	377.0
		18" pressure relief lines, missing 40'	750	578.4
		2" lines, missing 150'	750	3,408.0
	5th floor	none		
	4th Floor	8" line, missing 10'	750	717.1
		6" line, missing 20' vert.- 2' horiz.	530	612.0
		2 ½' line, missing 30' vert. - 20' horiz.	530	600.6
		2 ½' line, missing 15'	530	163.5
		2" line, missing 40' (B2 North side)	320	200.4
		12" line missing 35'	350	510.8
		8" line, missing 70'(steam drum lines: both boilers)	350	1,022
		20" line, missing 20' (dead head?)	530	1,549.2
	3rd Floor	8" line, missing 10' (dead head?),	320	139.9
		3" line, missing 25'	530	402.0
		18" line, missing 50' (vert.)	320	1285.5
	2nd Floor	8" line, missing 4' (to drum)	350	65.6
		1" line, missing 15'	350	33.5
	1st Floor	4" line, missing 30'	250	120.6
		8" line, missing 15'	350	246.1

		2" line, missing 30'	250	63.6
		1” line, missing 25’	250	29.5
Boiler 1	3rd Floor	10" line, missing 3’ vert. 20’ horiz.	530	933.8
	2nd Floor	8” line, missing 15’	350	246.1
		2” line, missing 4’	350	23.2
		8" line, missing 4’ (manifold?)	250	30.8
		12” line, missing 12’	350	278.6
	Adj. to TG Building	4" line, missing 30’	250	120.6
		8" line, missing 10’	250	90.2
	De-aerator	12" line, missing 20’	250	252.2
		10” line, missing 18’	250	195.7
		10” line, missing 5’ (loop @ north end)	750	440.8
		10” line, missing 8’	750	705.2
TG 4	4th Floor	1" line, missing 5’	750	57.4
		5” line, missing 6’	750	28.7
	Gen Rm.	2" line, missing 1’	750	20.1
		6" line, missing 10’	750	561.8
		4" line, missing 2’	750	79.1
	2nd Floor	1" line, missing 15’	750	172.2
		1" line, missing 13’ (off large line)	530	96.6
		8" line, missing 20’	750	1,392.2
	1st Floor	30" line, missing 10’	250	268.0
TG 3	1st Floor	30" line, missing 10’ (dead head)	250	268.0
		36” line, missing 40’	250	1310.4
TG 5 Bldg.		10" line, missing 5’ (roof line)	750	440.8
			Total Annual Heat Loss -	**71,542.6 MMBTU**

71,542.6 MMBTU = 2,981 tons coal (24.0 mmbtu/ton) or 8,876 tons bagasse (8.06 mmbtu/ton) or 12,442 bbls diesel (5.75 mmbtu/bbl)

2,981 tons coal = $208,670 ($70.00/ton)
12,442 bbls diesel = $808,730 ($65.00/bbl)