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STEAM PURITY FOR GEOTHERMAL POWER PLANTS

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Abstract

More attention needs to be paid to steam purity in geothermal power plants. In many cases, inadequate steam purity leads to performance degradation, turbine damage, and economic loss. Recent geothermal power plant experiences are discussed along with field test programs and retrofit approaches for resolving operating problems related to steam purity. Power plant design considerations for new facilities are also discussed.

Introduction

Inadequate steam purity from liquid-dominated or vapor-dominated geothermal resources can be detrimental to the long-term economical and reliable operation of a geothermal power plant. Contaminant materials in motive steam for geothermal power plants cause buildup of scale, corrosion, and/or turbine blade erosion. These effects reduce turbine efficiency and power output, and increase expenses for mechanical maintenance work. Significant revenue loss due to lower electrical output and forced outages may occur for both the power plant and resource owners.

There are two basic types of contaminants in geothermal steam: liquid entrainment and volatile chemical species. Liquid entrainment can generally be resolved adequately by mechanical separators. The volatile species consist of slightly volatile species such as silica, arsenic, and boron, as well as highly volatile substances such as carbon dioxide, hydrogen sulfide, and ammonia.

Under EPRI contract, Bechtel previously conducted a study to establish the steam purity criteria for geothermal power plants and methods to achieve these requirements commercially. As a result of this study, steam purity criteria for silica and total dissolved solids were developed and are shown in Table 1. The steam purity requirements were established based on information obtained from turbine manufacturers and review of the performance and reliability of existing geothermal power plants.

Treatment Technology

In most cases, primary and secondary mechanical separators provide steam of sufficient purity to allow for reliable operation. However, these separators do not remove volatile species; therefore, other steam cleaning technologies may be required for certain geothermal fields.

The most commonly used steam cleaning technologies in the geothermal industry are described below.

Bottom Outlet Cyclone. The bottom outlet cyclone (BOC) is most often used in the geothermal industry for liquid-dominated resources as a primary separator (i.e., to separate steam from large amounts of brine). The BOC is an easy to operate, highly efficient device that yields a steam separator efficiency of up to 99.95 percent in commercial geothermal power plants.

At vapor-dominated resources, devices like the BOC are not required for steam/brine separation. Instead, separators, often of the centrifugal type, are installed near the wellhead, primarily to remove large particulate matter originating from the resource and for initial removal of some entrained moisture.

Hook and Vane and Wire Mesh Separators. These devices are used for secondary separation (i.e., to remove carried-over brine droplets from steam and to separate the droplets by impingement). They typically remove 99.9 percent of the droplets with a minimum diameter of 8 to 10 microns.

Porta-Test Recycling Separator. Another secondary separator commonly used is the Porta-Test recycling separator, a centrifugal device. This separator is frequently used at The Geysers, California.

Scrubbers. For high salinity brines and brines containing high concentrations of silica, arsenic, and boron, the steam purity criteria may not be met with mechanical separators alone. In such cases, scrubbers can be used, using steam condensate as the scrubbing fluid. TDS, silica, boron, and arsenic can all be removed readily in this manner. Scrubbers can also be used to remove ammonia. However, other noncondensible gases such as carbon dioxide and hydrogen sulfide cannot be removed readily by scrubbers.

Plant Experience

Blundell Power Plant. Utah Power & Light (UP&L) Company constructed a 20 MWe (net) geothermal power plant at Roosevelt Hot Springs, a liquid dominated resource in southwest Utah. The plant started commercial operation in mid-1984. A schematic of the

steam gathering system is shown in Figure 1. Steam for the power plant flows from four production wells. The steam is separated from the brine at each wellhead top-outlet cyclones designed by by Phillips Petroleum. The remaining brine is reinjected. Near the power plant, a single main vertical centrifugal separator is installed for final moisture removal. After operating approximately four months, the maximum power generation capacity had dropped from 23.5 MWe (gross) to 17.5 MWe (gross). At this point, UP&L decided to shut the unit down for inspection. Inspection of the turbine revealed formation of whitish-gray scale on the stationary blades/diaphragm nozzles and the steam seals. The scale on the diaphragm nozzles was greatest in the first stage of the turbine. The severe scaling in the seal area resulted in the erosion of the steam seal labyrinth surfaces. Continued operation with excessive build-up of scale in the labyrinth steam seals is undesirable, due to potential permanent damage to the steel turbine shaft. Frequent short-time plant shutdowns would be prudent in order to remove the scale build-up in the seal area.

Analysis of the scale indicated that the deposits on the stationary blades were approximately 90 percent silica, the remainder primarily sodium chloride; while the scale on the steam seals consisted of 85 percent sodium chloride and only 10 percent silica.

During the inspection shutdown, the steam seals were refurbished and the turbine rotor and diaphragms were sandblasted to remove scale. In addition, modifications intended to improve the steam purity were made to the final moisture knock-out drum and one of the wellhead separators. A baffle plate in the wellhead separator was lowered, and a new internal collar was added to the knock-out drum.

Bottle Rock Power Plant. The State of California, Department of Water Resources, constructed a 55 MWe (net) geothermal power plant at a Lake County section of The Geysers. The power plant started commercial operation during March 1985. A schematic of the steam gathering system is shown in Figure 2. Steam for the power plant originates from wells located on three separate well pads. Rocks and entrained moisture are removed from the produced steam by horizontal centrifugal separators at each wellhead. Immediately following the wellhead separators, the steam is throttled to attain 30°F-plus superheat. The superheated condition is intended to minimize pipeline corrosion and power plant steam consumption. Near the power plant, a single main horizontal centrifugal separator is installed for final moisture removal. This centrifugal separator includes a vane-type element to serve as a coalescer. However, since the steam at this point is superheated, the effectiveness of the vane and centrifugal sections is minimal due to the absence of significant amounts of moisture.

Shortly after the start of commercial operation, the plant experienced the following difficulties:
1) degradation of the turbine/generator power output,
2) inoperability of stop valves on the motive steam line,
3) plugging of the strainers on the main steam line, and
4) corrosion of stainless steel piping and heat exchanger surfaces in the gas handling system.

Because of the inoperability of the main steam line

valves and the plugging of the strainer ahead of the steam turbine, the plant was shut down briefly within two weeks of the start of commercial operation. During this and subsequent shutdowns, inspection of the steam line valves revealed a buildup (mainly iron oxide, magnetite) on the valve stems. Although valves were cycled over a range of valve positions daily, several of the valves on the steam line to the turbine required repeated servicing to remove deposits during the initial operating period. Furthermore, during this period, bowl pressure above the 90 psi design condition (first stage inlet) was required to maintain 55 MWe (gross) turbine generator output.

The maximum turbine bowl pressure limit was reached within 60 days of commercial operation. At that time, the turbine-generator output had degraded to only 47 MWe (gross) with the turbine at the design conditions. At that point, operation of the power plant was suspended. Analysis of the scale samples taken from the turbine during the inspection is shown in Table 2. The analysis indicated that, as in the scale previously collected from the steam line valves, iron was the main component.

After shutdown of the power plant and the subsequent turbine inspection, a decision was made not to restart the power plant until the steam purity could be improved. There was no justification for bringing the power plant back on-line after a costly refurbishment of the turbine and other plant components, if the power plant could not remain on-line for a longer period of time.

In order to attain a longer operating period, the steam purity had to be improved. One approach to this would be to install a scrubber ahead of the turbine to remove particulates in the motive steam. The cost of such a steam cleaning facility was expected to be in the $1 million range. Six to nine months would be required for the scrubber installation.

A quicker approach, but one not expected to be as effective as the scrubber, is the use of water injection in the centrifugal separator near the turbine building. Water injection into the steam line is required to bring the superheated steam to saturation and to attain a few percent moisture in the steam. The presence of water droplets results in a scrubbing effect and improves the separator's efficiency, thus lowering the contaminants in the motive steam to the turbine.

It was decided to evaluate the quicker alternative via field tests using water injection with the existing centrifugal separator.

Field Testing

Blundell Plant. To investigate the turbine scaling problem, UP&L formed a team consisting of UP&L, Phillips, EPRI, and Bechtel personnel to conduct a field test program on the steam gathering system's performance.

One part of the testing consisted of monitoring the primary wellhead separators with respect to steam quality and purity under design and off-design conditions. Another was the monitoring of the motive steam to the turbine near the power plant before and

after the final moisture removal knock-out drum at full load, partial load, steady state, and upset conditions. Another was the monitoring of the condensate pot drainage system along the steam gathering pipeline between the producing wells and turbine building for chemical composition and mass flow.

Comprehensive chemical analysis of the brine and steam from each of the four production wells and the motive steam to the turbine was performed. However, during most of the testing, key chemical species tracked were limited to sodium, chloride, and silica. Turbine performance was also tested repeatedly to determine the turbine's maximum power output under design conditions in order to document turbine performance degradation trends.

Steam Purity Testing - Bottle Rock Plant. In order to optimize condensate water injection rates used for scrubbing of motive steam ahead of the final steam separator near the power plant and to monitor steam purity, a series of on-site analytical test procedures were developed. The analyses chosen were based in part on the turbine scale composition shown in Table 2, since these components represent major fouling constituents in the steam. Analytical methods developed to cover these fouling components and other major steam characteristics are shown in Table 3. Sample locations included the dry steam, steam after the separator, and the condensate from the surface condenser hotwell (i.e., source of the injection water for steam scrubbing). A laboratory manual including the Table 3 methods and other methods was prepared for the power plant chemists and operators.

During the test period a series of analyses were first performed to determine dry steam purity. Samples were taken using a multiport isokinetic sampling nozzle based on ASME specifications. The steam was cooled and the quantity measured in a graduated cylinder. A sampling rate was specified to assure representative sampling at each steam flow. Suspended solids in the steam were determined using an in-line steel filtering device containing a tared glass fiber filter. The noncooled steam was used for this sample. The sample quantity was determined for both the suspended solids and total steam sample by measuring the condensate produced for each sample involved. A schematic of the sampling system is shown in Figure 3. Sample conductivity, pH, and temperature were determined at the sample point. Other analyses were performed in the on-site plant laboratory. Care was taken to assure turbidity readings were made, using a completely filled airtight cell, within 5 minutes of sampling. This was to ensure that no oxidation of sulfide to sulfur occurred, since such oxidation would invalidate the determination. It was found that nitrogen sparging of the condensate samples for 20 minutes removed hydrogen sulfide to a sufficiently low level where it no longer interfered with the other colorimetric or volumetric analysis.

The values in column one of Table 4 represent the average of dry steam analyses taken during the test period. Of particular interest during sampling were the wide swings in iron concentrations in the unscrubbed steam, from as low as 0.1 to greater than 2.0 mg/L. These were probably caused by steam well operation changes and variability in well piping corrosion or

erosion rates. Because of the composition of the scale deposition in the turbine, iron concentration and the related turbidity were considered prime indicators of steam purity for the Bottle Rock plant. The relationship of steam iron concentration and turbidity is shown in Figure 4, based on a compilation of test sample iron and turbidity results. Correlation between these two determinations was found to be good, so that turbidity could be used as an indirect measurement of iron concentration.

To determine the optimum rate of steam ·condensate injection for the steam scrubbing operation, series of tests were run at water injection rates of 34, 64, and 90 gpm at a steam flow of 535,000 lbs/hr at 74 psig. The averages of dry steam purity, condensate injection water, and scrubbed steam purity (after the water injection and the final moisture separator) are shown in Table 4.

The concentration of iron (the principal component of the turbine scale) in scrubbed steam at various water injection rates is shown in Figure 5 as a function of water injection rate.

From Figure 5, it was determined that the preferred water injection was between 30 to 60 gpm at a steam flow of 535,000 lbs/hr, representing a 3 to 6 percent injection rate. Reduction in the amount of iron, as well as boron, silica, arsenic, and suspended solids (all possible scalants), was in the 60 to 90 percent range, as shown in Table 3. A maximum of 31 percent hydrogen sulfide and 29 percent ammonia were removed from the motive steam by the wet scrubber system at an injection rate of 64 gpm.

Discussion

Blundell Power Plant. Chemistry data collected during the field testing showed that the motive steam quality was greater than 99.95 percent and the motive steam to the turbine normally contained less than 1 ppm total dissolved solids (TDS) and less than 0.1 ppm silica with a pH of approximately 4.0. Despite the fact that the overall purity of the steam to the turbine was satisfactory (compared to other similar geothermal power plants and the previously established steam purity guidelines), significant scale formation occurred on the steam seals and first-stage diaphragm nozzles inside the turbine. Although the overall steam purity was considered high, some moisture droplets originating from the brine by entrainment at the wellhead separators probably remained in the motive steam to the turbine. Because the pressure drops across the steam seals and first-stage diaphragm in the turbine were relatively large, droplets of moisture suspended in the steam would tend to evaporate, resulting in mineral deposition.

The variance in deposit composition from the same steam source at different turbine locations can be attributed to the particular brine chemistry and the pressure/temperature conditions in the turbine. At Roosevelt Hot Springs, the geothermal brine from the wellhead separators contains approximately 725 ppm silica, which is very close to silica supersaturation. Brine droplets entrained in the steam are expected to have a composition very similar to that of the brine. In the·first-stage nozzle of the turbine, the motive steam

goes through a 45 psi pressure drop. This drop is large enough so the steam would tend to become superheated, and entrained droplets would start to evaporate. Since the entrained brine droplets are already near silica supersaturation, concentration of the droplets by evaporation would cause silica precipitation. The pressure drop was not enough so that the sodium chloride reached saturation. As a result, the bulk of the deposits found in the first-stage diaphragm nozzles is silica. However, in the steam seals, the steam goes through a larger pressure drop of nearly 90 psi. With this large pressure drop, concentration of the droplets by evaporation is enough to also reach sodium chloride saturation. As a result, the composition of the deposits in the steam seals is similar to that of the brine, which consists primarily of sodium chloride and silica.

To limit the formation of mineral deposits in localized areas inside the turbine, it was determined necessary to improve the efficiency of removal of small droplets near the turbine, and to lower the concentration of dissolved solids in droplets entrained in the steam.

After the field test program, UP&L considered improvement to the steam gathering system in three phases: 1) an improved condensate pot drainage system; 2) addition of a vane-type final moisture removal device; and 3) installation of a secondary steam scrubber facility consisting of a packed tower scrubber combined with a venturi scrubber. UP&L implemented the first phase by improving the performance of the existing 16 condensate pots along the steam gathering pipeline between the producing wells and turbine building by increasing the body diameter and length of the pots. Furthermore, UP&L installed an additional 25 condensate pots of this larger diameter and increased depth to enhance removal of moisture from the motive steam and to remove a substantial portion of those particles entrained in the steam which are affecting steam purity. The resultant improvement in steam purity was sufficient to eliminate the problem of deposition of silica and sodium chloride inside the turbine. Therefore steps 2 and 3 were not necessary.

Bottle Rock Power Plant. By choosing parameters and designing tests that give rapid and precise analytical values, it is possible to monitor plant steam purity and establish optimum rates for injection water into the steam line ahead of the existing horizontal centrifugal separator, to achieve a scrubbing effect. Based on the motive steam chemistry data collected during water injection testing, it was shown that a 90 percent reduction in the iron content (the main constituent of the scale depositions found inside the turbine) was achievable. Because iron was the main constituent of the scale, it was reasonable to assume that any improvement in the steam purity would result in a reduced amount of deposition in the turbine.

Since resuming operation at the beginning of August, 1985 with steam scrubbing by water injection, the Bottle Rock power plant has operated approximately 8 months without apparent power production loss due to scaling/deposition in the turbine. Inoperability of the valves on the motive steam line due to the buildup of deposits on the valve stems has not recurred. The recent inability of the power plant to operate at full power has been attributed to resource limitations.

It is important to maintain adequate steam monitoring and condensate purity so that operational problems resulting in unacceptable steam quality to the turbine can be avoided or corrected. Since iron, the principal impurity at Bottle Rock, correlates well with turbidity, an on-line ratio turbidimeter with an easily accessible and cleanable cell was recommended and is being purchased. Such a device can be set to sound an alarm at a preset turbidity level, notifying the plant chemist and operators that a water injection steam scrubber problem may be occurring. Follow-up analyses and actions to correct the problem would then be made. A schematic for an on-line turbidimeter is shown in Figure 6.

For Bottle Rock, a well designed and operated steam scrubbing system controlled by adequate laboratory and on-line analytical monitoring is essential to assure specified steam quality and long turbine runs.

Conclusion

Recent geothermal power plant experience indicates the need to revise existing motive steam purity criteria. For liquid-dominated resources, there appears to be a need for stricter purity requirements, particularly in cases where steam is generated from brines in which minerals exist at saturation. In addition, other criteria may need to be developed for other species such as iron and boron. Furthermore, there is a need for standardized sampling and analysis techniques to obtain accurate steam purity measurements in geothermal applications.

New geothermal power plant facilities should include steam cleaning facilities in the original design. The additional cost of such equipment, in the range of 1 percent of the geothermal power plant facility cost, is expected to more than pay for itself, considering the loss of revenue from electrical generation and geothermal fluid production, and the expenses for plant refurbishment.

In addition, power plant designers need to review carefully details of the turbine design. The steam seal design and pressure/temperature profiles of the turbine affect the likelihood of scale formation, if all other factors are equal. For example, the pressure drops across the first stage diaphragm nozzle are significantly different between impulse-type and reactionary-type turbines, and the fouling potential differs from one steam seal design to another.

The motive steam to the turbine should be closely monitored by an on-site laboratory and by on-line analysis to avoid power plant operation under conditions where deposition in the turbine is likely to occur. Additionally, a data base on the motive steam chemistry is a valuable resource in resolving steam purity related operational problems, should they occur.

Acknowledgement

Table 1
STEAM PURITY CRITERIA

	SiO_2 ppm	TDS ppm
Desired (conventional boiler criteria)	0.02	5
Allowable (slow scale buildup but no need for maintenance for at least 2 years; less than 10% power loss in 2 years)	0.1	15
Marginal (20% power loss in 1 year)	1.0	50

Table 2
ANALYSIS OF TURBINE SCALE, BOTTLE ROCK POWER PLANT

Component[1]	Composition %[2]
Iron (Fe)	Principal Constituent
Boron (B)	1.25
Silican (Si)	0.85
Arsenic (As)	0.60
Aluminum (Al)	0.35
Magnesium (Mg)	0.25
Calcium (Cu)	0.20
Manganese (Mn)	0.08
Copper (Cu)	0.06
Vanadium (V)	0.02
Tin (Sn)	0.02
Titanium (Ti)	0.015
Strontium (Sr)	0.01
Germanium (Ge)	0.01

1 Chromium, nickel, and molybdenum found assumed to be from turbine steel (< 2% of total).
2 Analysis by emission spectrography, reported as oxides.

Table 3
STEAM PURITY ANALYTICAL METHODS

Parameter	Sample Locations[1]	Instrument-Method
pH/pH[2]	DS WS HW	pH meter/glass electrode
Cond/Cond[2]	DS WS HW	Cond meter/cond cell
Turbidity	DS WS HW	Turbidimeter
Temperature (sample)	DS WS HW	Thermometer
Iron	DS WS HW	Spectrophotometer-0-phenanthroline method
Arsenic[2]	DS WS HW	Atomic Absorption (hydride)
Ammonia[2]	DS WS HW	Spectrophometer-Nessler
Boron[2]	DS WS HW	Spectrophotometer-Carminic Acid
Chloride[2]	DS WS HW	Titration-$Hg(NO_3)_2$
Hydrogen Sulphide	DS WS HW	Orion spec. ion-$AgNO_3$ Titration
Sulfate	DS WS HW	Spectrophotometer-turbidimetric
System Deposit Filtered Solids		Special Filter System Analytical Balance Atomic Absorption

1 DS = Dry steam before separator
  WS = Wet steam after separator
  HW = Condenser hotwell

2 Analysis noted is made after the sample is sparged for 20 minutes with N_2 at a rate of 500-ml/min. This effectively removes H_2S and CO_2 so that there are no interferences in the colorimetric or volumetric test procedures.

Table 4
WATER INJECTION TEST RESULTS SUMMARY
@ Steam Flow 535,000 lb/hr and 74 psig

Constituent	Average Dry Steam	Average Inject Water	Water Injection 34 GPM (3% Water) Value / % Reduction	64 GPM (6% Water) Value / % Reduction	90 GPM (8% Water) Value / % Reduction
Cond @ 30°C umhos/cm	730	450	565 / 23%	568 / 22%	660 / 10%
pH @ 30°C	6.0	8.6	6.2 / *	6.2 / *	5.8 / *
As ppb	90	3.2	ND	6 / 93%	32 / 64% (120 gpm)
Turbidity NTU	2.8	4.5	0.8	0.7	3.0
B ppm	45	–	25 / 67%	20 / 56%	35 / 22%
Cl ppm	<4	–	<1 / 75%	<1 / 75%	<1 / 0%
Fe ppm	0.4	1.6	0.02 / 95%	0.1 / 75%	0.4 / 0%
SiO_2 ppm	0.12	–	0.05 / 58%	0.02 / 84%	0.2 / increase
Total Solids ppm	320	–	~210 (est)	~210 (est)	~265 (est)
Susp. Solids ppm	50	–	~40 (est)	~210 (est)	~25 (est)
Diss. Solids ppm	270	–	~200 (est)	~200 (est)	~245 (est)
H_2S Total ppm	200	–	ND	207 / *	194 / *
H_2S Cond. ppm	90	–	ND	62 / 31%	100 / *
NH_3 as N ppm	75	–	56 / 25%	52 / 29%	50 / 33%
Estimated steam quality from separator			99.94%	99.96%	99.02%

Cond, As, B, Cl, SiO_2, NH_3, solids are all significantly reduced @ 30-60 GPM (3-6% injection)
ND = no data
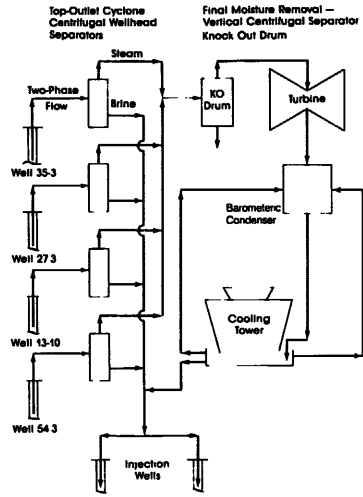* Change considered insignificant

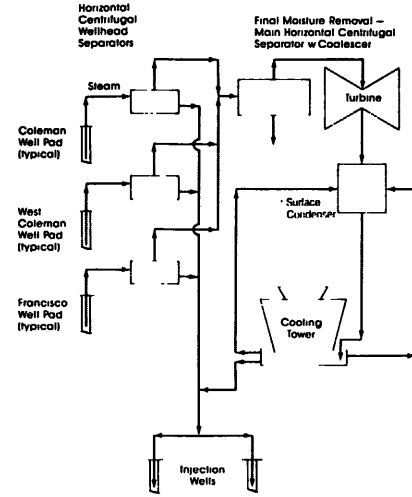Figure 1. UP&L Blundell well gathering system schematic

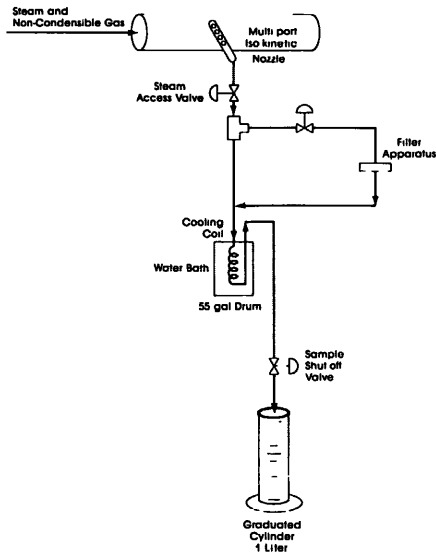Figure 2. DWR Bottle Rock steam gathering system schematic

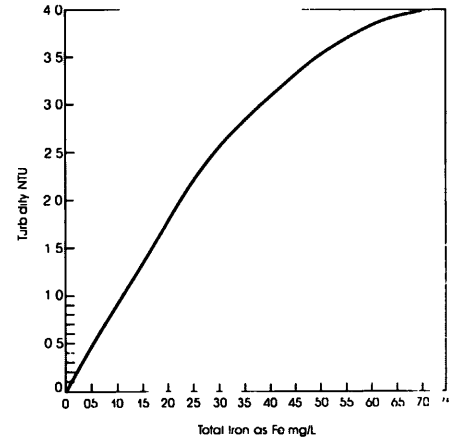Figure 3. Steam sampling system

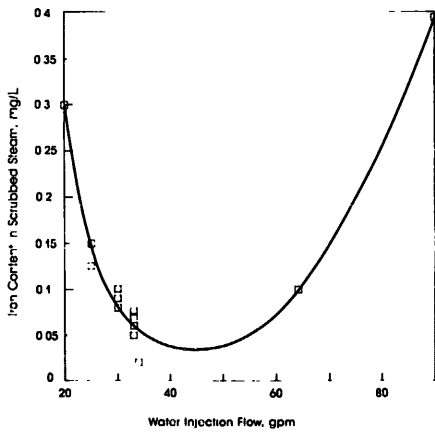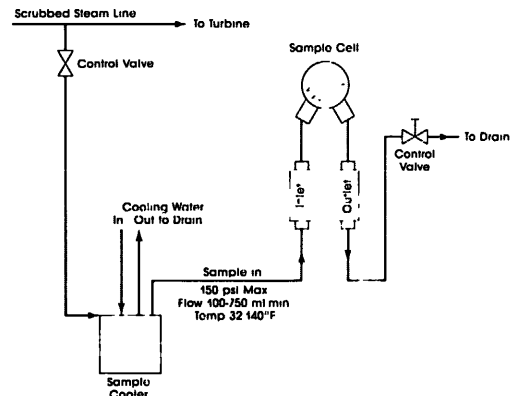Figure 4. Correlation of iron and turbidity measurement

Figure 5. Iron removal by water injection

Figure 6. Sample hookup for on-line ratio turbidimeter