Rodeo Refinery
Loss of Cogeneration Units 102210-1 ID#144138
October 22, 2010

Incident Investigation Report

Executive Summary

Location: Rodeo Refinery
Date of Incident: **October 22, 2010**
Date Investigation Began: **October 22, 2010**
Time of Incident: **10:45 AM**
Name of Incident: Loss of Cogen Units 102210-1
Incident Risk Ranking: **Category II (Community Impact)**

At 10:43 am on Friday, October 22 the Air Liquide hydrogen plant (Unit 120) shutdown unexpectedly which caused the refinery to stop or restrict production on hydro-treating and hydro-cracking units. Unit 120 was providing 105 MMSCFD of hydrogen and 174 MLB/Hr of steam to the refinery. When the refinery suddenly lost the steam production from Air Liquide the steam and fuel systems went through sudden changes causing the loss one of the SPP (Steam Power Plant) cogeneration unit turbines. A steam curtailment emergency procedure was implemented immediately. After five starting attempts, GTG23A (A Turbine) was producing steam at 1:30 PM. Operators and maintenance technicians were unable to synchronize the generator to the power grid. Troubleshooting efforts caused A Turbine to trip at 1:57 PM causing the 600# steam system pressure to drop. When the 600# (High Pressure) Steam system dropped to 560#, an air purge, on the steam injection system, caused a flameout of C Turbine by blowing condensate into the fuel nozzles. There was a severe loss of instrument air after the loss of C Turbine. The remaining B Turbine shutdown when the governor system could not adjust the fuel flow without instrument air. The shutdown of refinery process units resulted in a smoky flare which is a community impact. Due to visible smoke from the refinery, a Community Warning System (CWS) Level 2 notification was made to the Contra Costa County Hazardous Material Notification Policy. A CWS Level 2 is a "Major Chemical Accident or Release" (MCAR) as defined by the Industrial Safety Ordinance.

Key Findings and High Value Learnings

The physical causes of this incident, which played out in unique cascading steps, included:

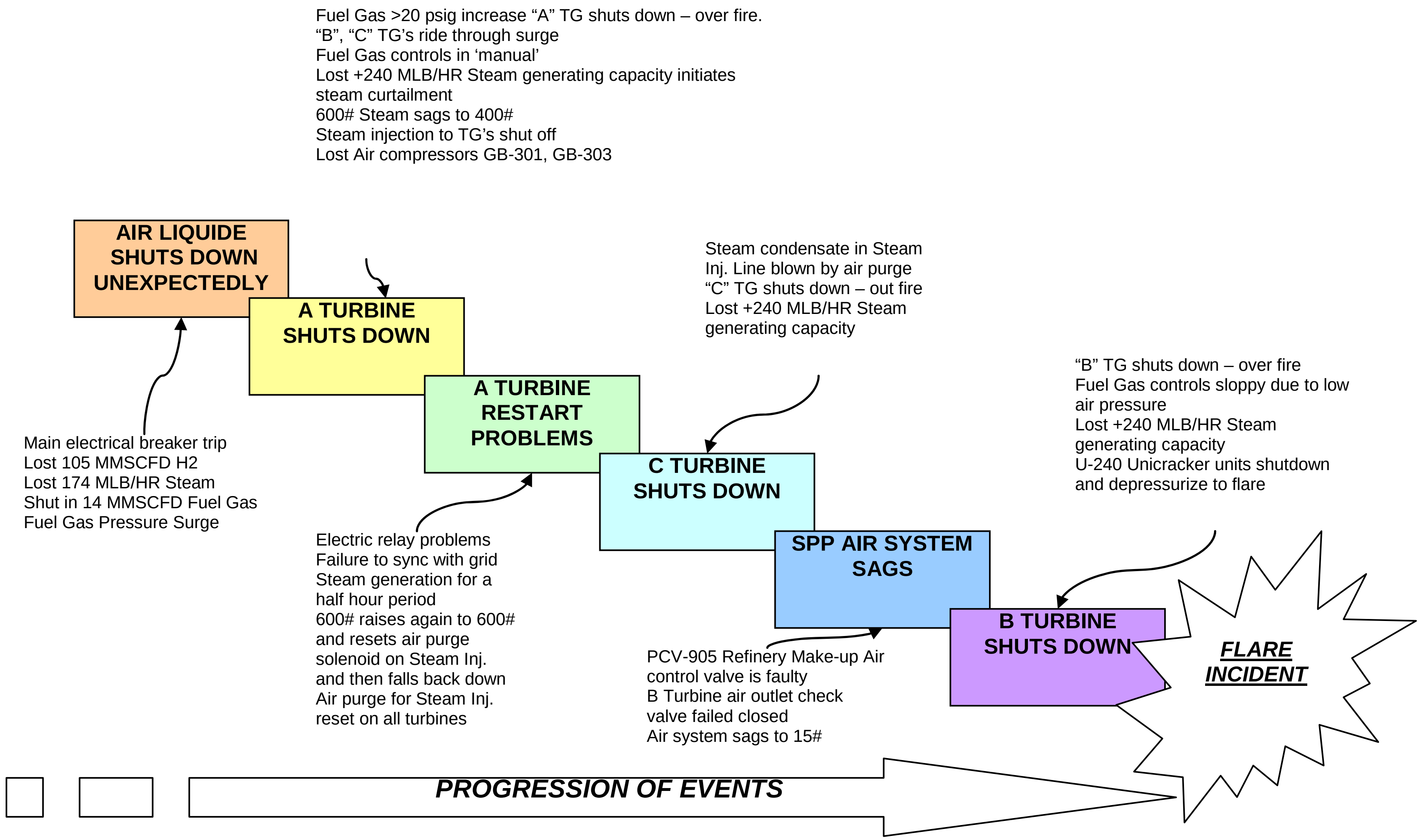
1) The fuel gas system pressure jump caused by the Air Liquide shutdown caused the shutdown of "A" Gas Turbine Generator

2) The inability to restart "A" Gas Turbine Generator associated with electrical circuit problems caused the second trip of the "A" Gas Turbine Generator (GTG23A).

3) The automatic air purge on the steam injection system caused a flameout on the C Turbine, and

4) The loss of instrument air due to system leakage/stuck check valve and faulty make-up air pressure control valve caused the shutdown of B Turbine.

Refer to the graphic on the next page which shows the progression of the events with notations.



Fuel Gas >20 psig increase “A” TG shuts down – over fire.
“B”, “C” TG’s ride through surge
Fuel Gas controls in ‘manual’
Lost +240 MLB/HR Steam generating capacity initiates steam curtailment
600# Steam sags to 400#
Steam injection to TG’s shut off
Lost Air compressors GB-301, GB-303
AIR LIQUIDE SHUTS DOWN UNEXPECTEDLY
A TURBINE SHUTS DOWN
A TURBINE RESTART PROBLEMS
C TURBINE SHUTS DOWN
SPP AIR SYSTEM SAGS
B TURBINE SHUTS DOWN
FLARE INCIDENT
Main electrical breaker trip
Lost 105 MMSCFD H2
Lost 174 MLB/HR Steam
Shut in 14 MMSCFD Fuel Gas
Fuel Gas Pressure Surge
Electric relay problems
Failure to sync with grid
Steam generation for a half hour period
600# raises again to 600# and resets air purge solenoid on Steam Inj. and then falls back down
Air purge for Steam Inj. reset on all turbines
Steam condensate in Steam Inj. Line blown by air purge
“C” TG shuts down – out fire
Lost +240 MLB/HR Steam generating capacity
PCV-905 Refinery Make-up Air control valve is faulty
B Turbine air outlet check valve failed closed
Air system sags to 15#
“B” TG shuts down – over fire
Fuel Gas controls sloppy due to low air pressure
Lost +240 MLB/HR Steam generating capacity
U-240 Unicracker units shutdown and depressurize to flare
PROGRESSION OF EVENTS

INCIDENT INVESTIGATION REPORT

RODEO REFINERY- Loss of Cogeneration Units 102210-1

BACKGROUND

The Rodeo Refinery is supplied steam and hydrogen (in the future electricity will be supplied) from a third party, Air Liquide, since the start-up of the HEP (Hydrocracker Expansion Project) in September 2009. The Air Liquide Hydrogen Plant, Unit 120, is supplied Refinery fuel gas, boiler feed water, and air. Although there have been previous sudden shutdowns of the Air Liquide hydrogen unit, the previous consequences were loss of production and flaring. The loss of hydrogen forces Unit 246, the Heavy Oil Hydro-cracking Unit to stop production. Unit 250, the Diesel Hydro-Treating process must also shutdown after an Air Liquide shutdown. During 2010, all previous Unit 120 shutdowns were at much lower hydrogen production rates except one on October 6th. Four of the ten shutdown events (including this event) in 2010 resulted in flaring with SO_2 emissions greater than the Reportable Quantity of 500 lbs.

The refinery maintains a steam reserve capacity to mitigate the effects of losing any one of the major steam producers. Three gas turbine generators with heat recovery steam generators at the Steam Power Plant and Air Liquide are the major producers of steam. Steam production rate is controlled by the Refinery 600# steam system pressure. The refinery wide emergency operating procedure for steam curtailment includes the new HEP units and Air Liquide's operation. Process units have emergency steam curtailment procedures that are implemented when directed by shift supervision or unit conditions.

The three gas turbine generators at the Steam Power Plant are designated GTG23 A, B, and C (this report will use the terms A Turbine, B Turbine, or C Turbine). Fuel gas from the refinery or natural gas from PG&E (Pacific Gas and Electric Company) is supplied to compressors to provide fuel for the turbines or the COEN duct burners. "A" Turbine has a Woodward control system while "B" & "C" Turbines have newer Triconex systems. Both systems control turbine operation by throttling the fuel to the turbine to drive a generator. Operation of the gas turbine generators is normally in an automatic mode limited by the exhaust gas temperature. The COEN burners provide added heat to generate additional steam as determined by 600# Steam system pressure.

DESCRIPTION OF ACTIONS BEFORE THE EVENT

On October 22, 2010 at 10:43 AM, Unit 120 was reportedly shutdown by a trip of the main electrical supply breaker. The trip was the result of a high pump bearing temperature alarm and the slow response of the pump's circuit breaker. The system is designed to protect the plant from an apparent short circuit in the pump's power supply. The loss of power caused the plant shutdown.

The Refinery was supplying Unit 120 with 14 MMSCFD (million standard cubic feet per day) of fuel gas prior to the shutdown. Unit 120 was exporting 105 MMSCFD of hydrogen and 174 MLB/Hr (thousand pounds per hour) of steam to the refinery. An initial jump in steam exports occurred because of the shutdown. Steam supplied to the refinery increased for four minutes before flow ceased. The Refinery 600# steam system pressure dropped to 400# by 11:00 AM. The refinery fuel gas system was severely out of balance and pressure increased. Since Unit 120 was no longer using 14 MMSCFD of Fuel Gas the Refinery Fuel Gas Center vented to the flare to control pressure. A Community Warning System

Level 1 was called at 11:08 AM due to the excessive flaring. The hydrogen consuming units, Unit 246 Hydrocracker and Unit 250 Diesel Hydrotreater, transitioned to a circulating mode of operation. Unit 240 Hydrocracker went to minimum flow through the First Stage Reactor and shutdown the Second Stage to limit hydrogen consumption.

After five starting attempts, A Turbine was operating and producing steam by 1:30 PM. Operators and maintenance technicians were unable to synchronize the generator to the power grid. Troubleshooting efforts caused A Turbine to trip at 1:57 PM causing the 600# steam system pressure to drop. Ten minutes after the 600# steam system pressure dropped to 560#, an air purge was system activated on the steam injection lines of the running turbines. The steam injection was off line since the initial steam pressure drop at about 11:00 AM. When the 600# steam system was restored by running the A turbine, a permissive relay was reset. It is believed that condensate collected in the C Turbine steam injection line and was blown into the turbine fuel nozzles causing a flameout. (The similar problem did not occur on the B Turbine. The steam injection dropout valve on B Turbine was discovered leaking about 500 pounds per hour. This prevented the B Turbine steam injection line from cooling and collecting condensate.) The SPP Instrument Air system pressure began to drop quickly after C Turbine shutdown. The loss of air prevented the control system from adjusting the fuel throttle valve leading to the high combustor temperature shutdown of B Turbine.

INCIDENT DESCRIPTION

The loss of all three cogeneration units caused a severe drop in the 600# steam system. The steam driven hydrogen recycle compressor at Unit 240 Plant 2 is an important user of 600# steam. The low recycle gas flow initiated an automatic 100PSI/minute depressurization of the process reactors. This vented large amounts of hydrocarbons to the Refinery flare and exceeded the designed smokeless capacity. When black smoke from the Refinery flare became persistent a Community Warning System 2 Level was activated and a Refinery shutdown was implemented to ensure all processes were placed in safe conditions. There were no other process upsets or consequences during the shutdown. There were no injuries or illness complaints from employees, contractors, or the public.

Refinery personnel conducted field observations and monitoring downwind. No significant evidence of impact to the community was found. There were odor and visible smoke complaints received by the Bay Area Air Quality Management District (BAAQMD) during the event. There was no significant activity on Ground Level Monitors or Fenceline monitoring systems. All field instrument readings for contaminants were less than detectable. The Contra Costa County Hazardous Material Response team did independent monitoring off site. Sample results showed no detection of hydrocarbon or sulfur compounds.

Notifications were made to the County Health Services, BAAQMD, Rodeo Hercules Fire Dispatcher, Crockett Fire Department, and Contra Costa County Office of Emergency Services with the CWS Level 1 Terminal notification. Additional phone notifications were made as event progressed. At 2:38 PM, A CWS Level 2 notification was made. The Environmental Services Department also made phone notifications to BAAQMD. The Loss of Cogeneration Units is classified as a Community Impact event and was risk ranked at Category II using the ConocoPhillips Risk Ranking Matrix. A CWS Level 2 is an MCAR (Major Chemical Accident or Release) incident as defined by the Contra Costa County Hazardous Material Incident Notification Policy and the Industrial Safety Ordinance. This investigation report was prepared according to the format required by the Refining Required Standard Incident Investigation and Reporting and the county requirements. A Full Team Level investigation was assigned as required by Policy 5-3, Investigation Work Process.

Sequence of Events:

TIME	EVENT
1043	Air Liquide shutdown of Unit 120
1044	SPP A Turbine shutdown on high basket temperature
1100	Steam Curtailment Implemented as 600# Steam “sags” to 400#
1113	CWS Level 1 – Excessive Flaring
1200	600# Steam “recovers” to 450-500#
1319	A Turbine running with COENS > 600# Steam
1357	A Turbine shutdown by generator trip
1411	Steam Injection Air Purge Activated
1412	SPP C Turbine shutdown – flameout
1427	SPP B Turbine shutdown on high basket temperature
~1430	Refinery Flare Smoking
1437	CWS Level 2 – Smoke visible off site
1505	U240 depressurizing to flare

INCIDENT CAUSES

Members of the investigation team began the investigation shortly after the incident on October 22nd and documented plant conditions. A smaller team investigated the process data including alarms to determine the causes of the turbine shutdowns.

Members of the team conducted interviews with employees and reviewed the policies, procedures, and plant data related to the event. Similar incidents were reviewed.

The event log established a time for key events. See Attachments 2 and 3.

The team conducted training on the use of the Human Factors checklist and the use of TapRooT® prior to conducting the root cause analysis phase of the investigation.

There were key events that led to the loss of all cogeneration units. These key events identified the causal factors that were analyzed for root causes.

- Air Liquide shutdown of Unit 120; contributing factor since Unit 120 operation is not under refinery control. This was the initiating event for the A Turbine shutdown because it caused a sharp increase in the refinery fuel gas system pressure.
- Fuel gas pressure increased 20 PSI; causal factor; physical cause of shutdown of A Turbine. The A Gas Turbine controls are not adequate to reliably control the Fuel Gas pressure surge caused by a Unit 120 unscheduled shutdown. A Gas Turbine stayed on-line in other Air Liquide sudden failures but not during this incident. The A Turbine shutdown was due to over firing, high basket temperatures, caused by a <20 psig fuel pressure surge while B and C Gas Turbines stayed on line with a >70 psig fuel pressure surge. B and C Gas Turbine control instrumentation was upgraded to a Digital Triconex PLC turbine control system in 2003 and 2004. A recent, previous investigation of a Unit 120 shutdown (Sept. 13, 2010) made recommendations to mitigate fuel gas problems but the corrective actions were not implemented yet.
- Condensate blown into GT23C by air purge; causal factor, direct cause of C Turbine shutdown. Condensate collected in the steam injection line despite a water trap. The air purge subsystem trips

and resets based on the 600# steam pressure. Steam Injection had not been restored since the original drop out at ~11:00 AM. The normal shutdown and startup procedures do not cover the steam injection. It has a separate procedure which was not used because there was no priority in restoring this during the refinery upset. After this incident, the area supervisor added a step to the SPP steam curtailment procedure to isolate the steam injection from the turbines after a drop out occurs. Operators were trained and notified of the change and the reason for the new step.

- Loss of SPP Instrument Air; causal factor, direct cause of B Turbine shutdown since it removed the control systems ability to reposition the fuel throttle valve. The SPP instrument air pressure dropped rapidly after the shutdown of C Turbine. The low air pressure resulted in poor firing control for B-Turbine and caused the shutdown due to an over-fire condition. In the past, air from a single SPP turbine was sufficient to supply all internal SPP air demands. The B Gas Turbine air outlet check valve was found stuck shut during an inspection in December, 2010 after this incident which explains why the SPP air pressure was lost. The Refinery air system was unable to supply enough make-up air to maintain pressure because the pressure control valve was faulty. This was found later in an instrument shop inspection.
- PHYSICAL CAUSES: [direct causes]

The physical causes of this incident were the fuel gas system pressure jump caused by the Air Liquide shutdown and equipment reliability issues at the Steam Power Plant (SPP). Electrical circuit problems caused the second trip of the A Turbine. The air purge on the steam injection system caused a flameout on the C Turbine unit, and the subsequent loss of instrument air caused the shutdown of B Turbine.

Health, Safety, and Environmental Management System (HSEMS):
The HSEMS elements involved in this incident are listed for use during the annual HSE Excellence Assessment process. The needed improvements for these elements should be discussed and developed during the assessment process.

- Programs and Procedures
- Asset and Operating Integrity

ROOT CAUSES for CAUSAL FACTORS

Air Liquide shutdown of Unit 120

Analysis not performed since the refinery has no operational control over Unit 120. An earlier investigation, Air Liquide Shutdown 091310-2, made recommendations to decrease the impact of a Unit 120 shutdown on the Fuel Gas System to minimize flaring. See IMPACT ID 140145.

Fuel gas pressure increased 20 PSI

Equipment Difficulty: Design Specs: Problem Not Anticipated

The SPP Turbine fuel gas pressure control systems were not designed to handle sharp transients as large as the recent U120 shutdowns with higher levels of Refinery fuel gas being returned suddenly to the Refinery Fuel Gas Center. The newer Triconex systems did not trip B or C Turbines but there were severe transients in the power output of these generators after the Unit 120 shutdown. (An Air Liquide shutdown on Oct. 6 with similar Hydrogen production rates did not cause a shutdown of any SPP Turbines.)

Equipment Difficulty: Design Review: Independent Review NI; MOC NI

The design review of the changes to the fuel gas system to support the HEP project did not identify or prioritize the effects of a Unit 120 shutdown. The frequency of the shutdowns may have been estimated to be rare enough to lower the overall risk. The past year record of shutdowns has required a new review of potential mitigation steps. The investigation of the September 13, 2010 Unit 120 shutdown was focused on minimizing the flaring and fuel gas consequences of a Unit 120 shutdown.

Management System; Corrective Action; Not Implemented

The recommendations from the September 13th investigation have not been implemented or evaluated for approval yet. The analysis of this report identified the risks of future shutdowns with our existing operating plan. One of the recommendations was the implementation of the draft Unit 120 shutdown emergency operating procedure.

Condensate blown into GT23C by air purge

Procedures; Wrong; Situation Not Covered

The unique conditions involved in this event were not considered since they never happened before.

Management System; SPAC; Confusing or Incomplete

The SPP steam curtailment procedure did not have a step to isolate the steam injection on all turbines after a system drop out.

Loss of SPP Instrument Air

Equipment; Preventive Maintenance; No PM

The Gas Turbine air system exhaust check valves were not identified as requiring ongoing PM to prevent air flow loss (supply out to the system, or leakage back to a shutdown turbine).

RECOMMENDATIONS AND FOLLOW-UP ACTIONS

Unit 120 Shutdown

Recommendation 1:

The Unit 120 Hydrogen Plant unscheduled shutdowns will likely cause significant San Francisco Refinery (SFR) upsets due to the sudden loss of Hydrogen and a surge of 15 – 20+MMSCF/D of gas into the Sweet Fuel Gas System. Causes and recommendations to improve the Unit 120 reliability are outside the scope of this investigation. The Incident Investigation Report for the 9/13/10 Flaring Event due to a Unit 120 shutdown was issued on 10/7/10. The 9/13/10 Incident Report included recommendations to decrease the impact on the Fuel Gas System and minimize the Flaring event including revising and finalizing the EOP for an emergency Unit 120 shutdown event. Recommendations included the following:

A. Add a second Unit PV-6400 dump valve of Sweet Fuel Gas to the Flare size for about 15 MMSCF/D. The current PV-6400 will divert about 7 MMSCF/D of Sweet Fuel Gas to the Flare. A Unit 120 shutdown will surge about 15 – 20+ MMSCF/D of gas to the Sweet Fuel Gas System. Note: An engineering project request was completed and the design study is underway for completion of piping tie-ins during the mid-year 2011 turnaround period.

B. Immediately cut Unit 231 Magnaformer rate to 12 MB/D, Coker Coil Charge to 6 MB/D, and Unit 200 crude rates to minimum to reduce Sour Gas production.

C. Operate Unit 240 Plant 4 Hydrogen Plant that will provide emergency Hydrogen, Steam, and consume Fuel Gas. Note: Unit 240 Plant 4, which was down for maintenance at the time of this incident, was restarted to add a buffer effect in the Fuel Gas system in case there is another Air Liquide outage that might generate a Fuel Gas pressure surge.

A separate joint SFR and Air Liquide Team is investigating issues to improve Unit 120 reliability.

Fuel Gas pressure increased by 20 psi causing A-Turbine shutdown:

Recommendation 2:

A. Identify and implement solutions to the fuel gas system pressure surge when U120 shuts down with engineering evaluation and progress action levels. The following table is by no means all of the engineering solutions, but lists initial thoughts from the team and operations personnel. Further engineering analysis is required. The initial actions A. through D. may be found to be adequate to address the problem:

Potential Action	Effect	Difficulty
A. Retune PV6400 at Unit 233 for faster response to open faster and relieve fuel gas pressure spike	Allow faster response to relieve fuel gas pressure spike by venting to flare	Quick and easy; Completed
B. Reduce level of fuel gas pressure spike by controlling amount of RFG-A rate to U-120 in conjunction with operation of U240 Plant 4.	Greatly reduces/dampens the level of fuel gas spike going to SPP	Quick and easy; Completed; ongoing evaluation of the right combination based on operating situations.

C. Enhance PV6400 pressure control capability (larger valve, or second parallel valve of "X" capacity)	Greatly increases the action to control pressure spikes	Requires engineering and hardware/ MOC; best done during 2011 mid-year turnaround to avoid hot tapping HC gas piping. Engineering study initiated.
D. Improve fuel gas control at SPP by tuning fuel gas skids, lowering pressure on Ranerex to 165-175 psig, placing controls on automatic, etc…	Improves fuel gas pressure control to gas turbines; reduced Fuel Gas pressure to improve the response time/margin to a Fuel Gas pressure spike.	Requires instrument reliability and engineer support, hardware/ MOC. Best done during the three SPP turbine outages in early 2011. Reliability evaluation initiated.
E. Further potential actions if above steps are determined to be inadequate: 1. Install a suction pressure control valve on the F-17 overhead line, G-17 Fuel gas Compressor suction line, to control the Unit 233 Fuel Gas pressure at 65 – 70 psig. 2. Upgrade the A-Turbine Woodward Governor controls to the equivalent of the Digital Triconex controls (an B, C Turbines)	Eliminate pressure surge Allow these turbines to operate through the Fuel Gas pressure surge; facilitates restart of turbine generator	Requires engineering, hardware/ MOC. Timing difficult unless refinery-wide outage. Hot tap connections may be required. Major controls engineering, hardware/ MOC. Currently phase timing for ~2014.

B. Expedite the issuance of REOP for Unit 120 shutdown. Ensure it includes appropriate actions to cover scenarios that address Unit 240 Plant 4 running and also not running.

Condensate swept into C-Turbine (Second Turbine to shutdown) due to air purge activation

Recommendation 3:

The activation of the air purge was an unexpected result of the 600# steam system pressure transients.

A. Revise the SPP Turbine Emergency Shutdown Procedure to block in the Steam Injection for all operating Turbines if the Steam Injection is lost for any reason. This action will have priority over the actions to restart a turbine to prevent the inadvertent shutdown of the operating turbines. Note: This procedure change was made and operators trained per MOC requirements.

B. Consider changing the Air Purge drop out to include a manual reset before it can be activated after a drop-out event.

B-Turbine (Third Turbine shutdown) SPP Instrument Air Header lost pressure.

Recommendation 4:

After the C Turbine shutdown, the SPP Instrument Air pressure lost pressure rapidly. The letdown from the refinery air system could not keep up with the air loss. Later turbine shutdown events have indicated that there is likely a severe air leak present in the system. One potential location is the C Turbine compressor discharge check valve based on system responses.

A. Consider revising the SPP Turbine Emergency Shutdown Procedure to block in the Instrument Air to both of the shutdown turbines to prevent loss of Instrument Air. When a turbine is ready to start open the SPP Instrument Air block valve and continue with the startup.

B. Emergency Refinery Air make-up control valve PCV-905 did not fully open when the SPP Instrument Air pressure dropped below the set point of 80 psig. Remove and repair or replace the PCV-905 pressure regulator to ensure that it will fully open when the SPP Instrument Air pressure drops below 80 psig. Note: This was completed and internal parts failure were found when valve PCV-905 was removed/inspected/serviced/tested/reinstalled.

C. Consider troubleshooting the SPP Instrument Air system for leaks, such as the turbine compressor outlet check valves. Note: B Turbine check valve was repaired after the incident in December, 2010. The outlet check valves will be inspected/serviced/tested during the individual SPP A and C Turbine Generator outages in early 2011.

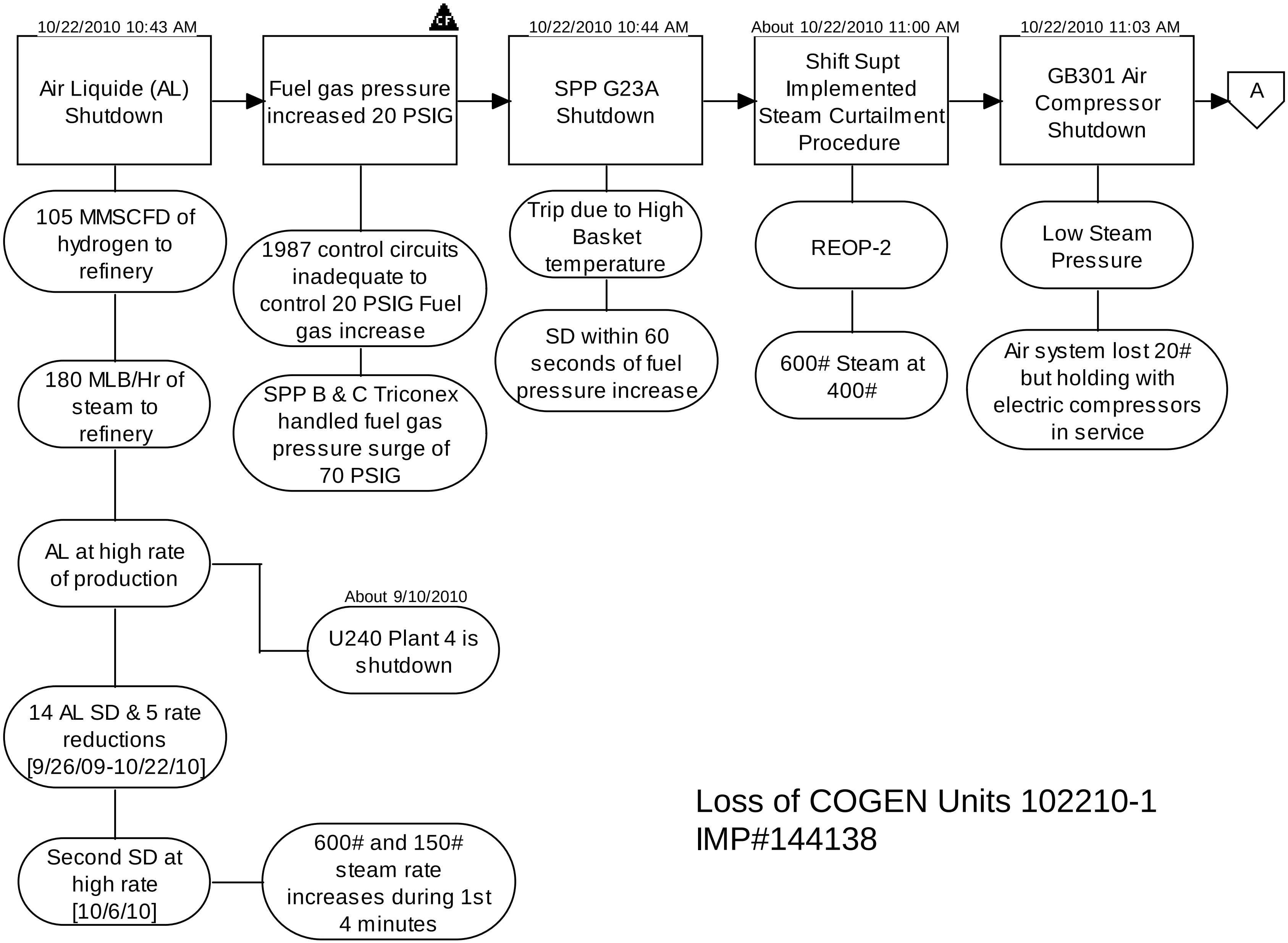
INVESTIGATION TEAM

The team members were: ME&I Superintendent (Leader), Senior Process Engineer, SPP Operator, Marine Terminal Dispatcher (JHSC member), and H&S Special Projects Coordinator (TapRooT® Facilitator).

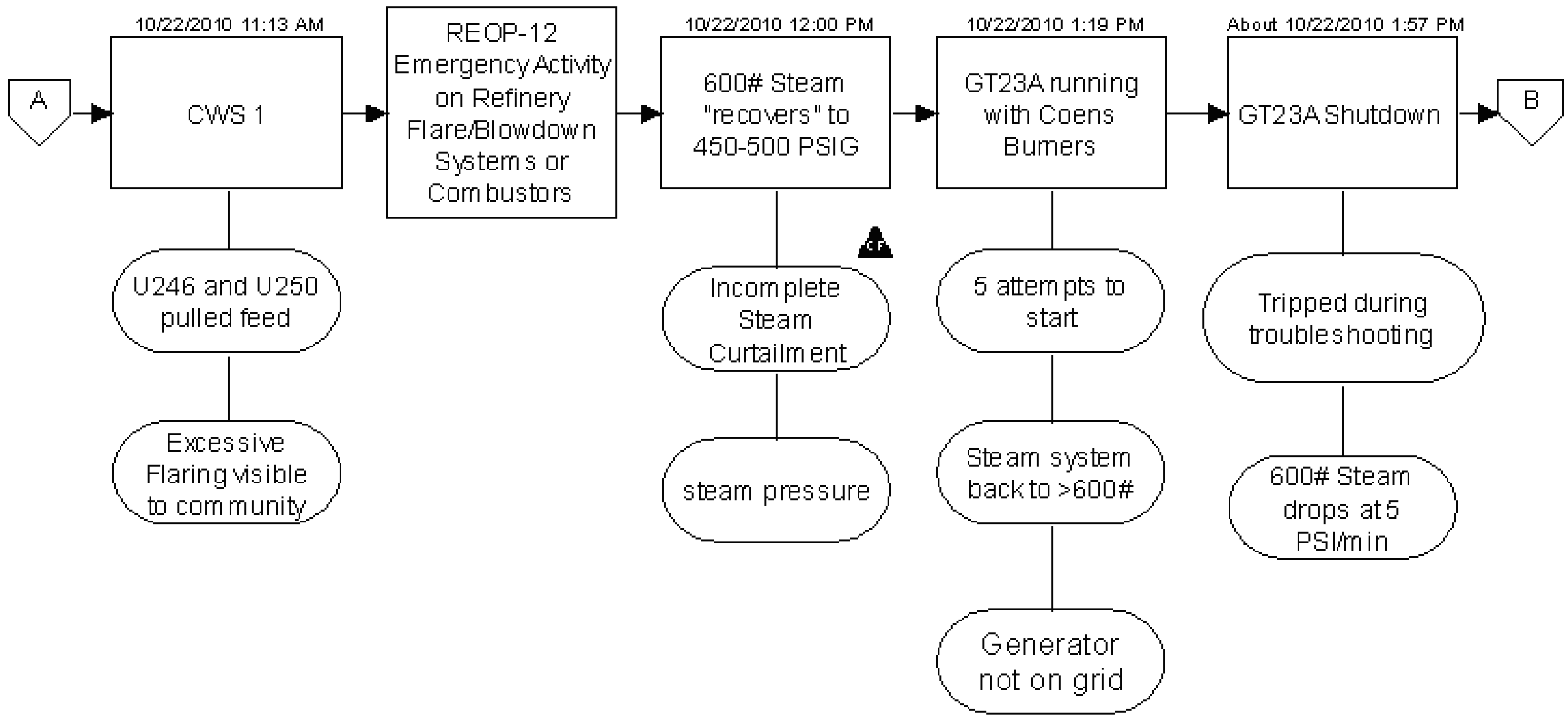
ATTACHMENTS

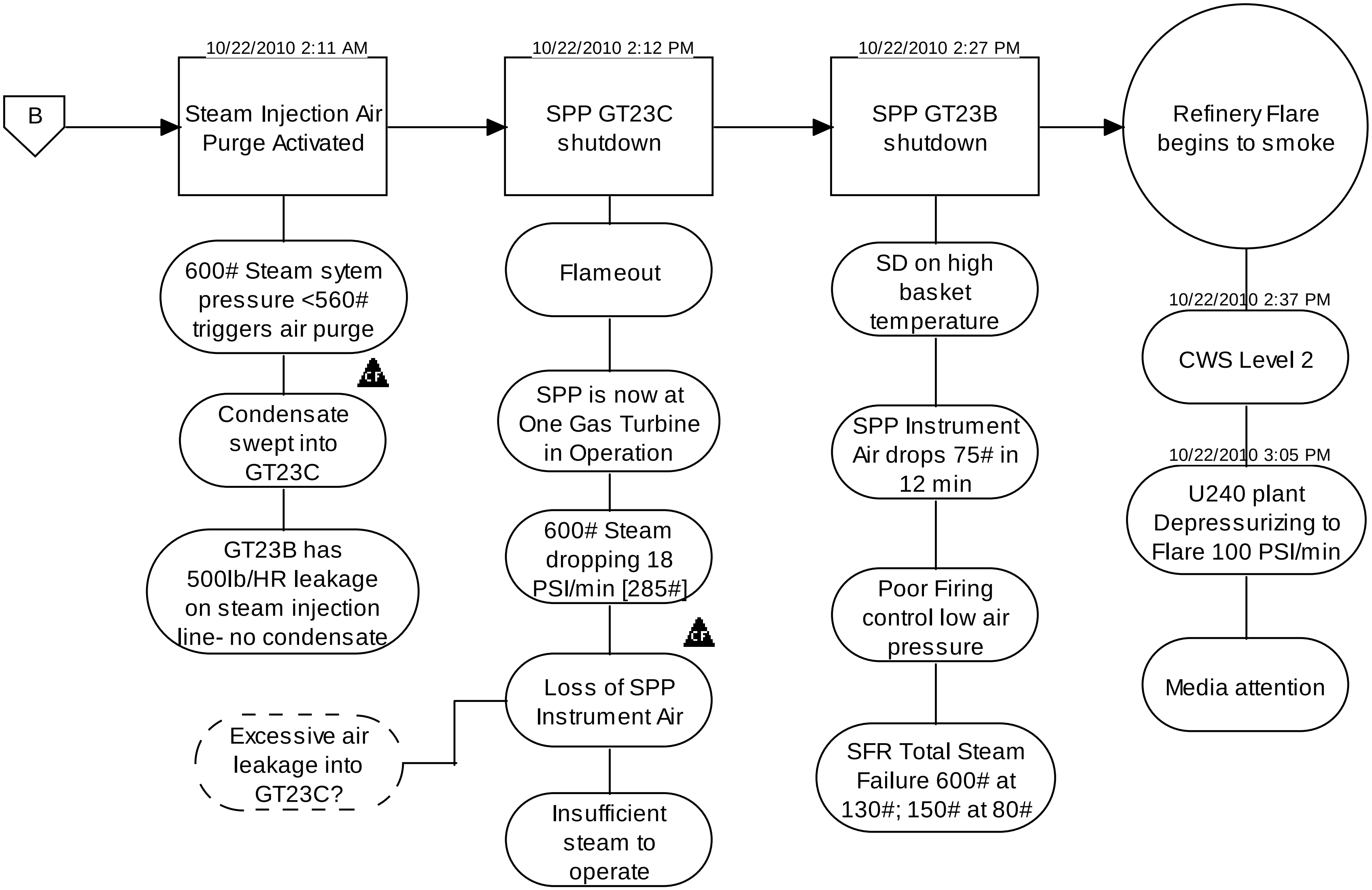
1. TapRoot® SnapChart
2. Event Summary – October 22, 2010
3. Steam System Event Summary – October 22, 2010
4. Plant Instrumentation Trend Charts

ATTACHMENT 1



Loss of COGEN Units 102210-1
IMP#144138


A
10/22/2010 11:13 AM
CWS 1
U246 and U250 pulled feed
Excessive Flaring visible to community
REOP-12 Emergency Activity on Refinery Flare/Blowdown Systems or Combustors
10/22/2010 12:00 PM
600# Steam "recovers" to 450-500 PSIG
Incomplete Steam Curtailment
steam pressure
10/22/2010 1:19 PM
GT23A running with Coens Burners
5 attempts to start
Steam system back to >600#
Generator not on grid
About 10/22/2010 1:57 PM
GT23A Shutdown
Tripped during troubleshooting
600# Steam drops at 5 PSI/min
B


B
10/22/2010 2:11 AM
Steam Injection Air Purge Activated
10/22/2010 2:12 PM
SPP GT23C shutdown
10/22/2010 2:27 PM
SPP GT23B shutdown
Refinery Flare begins to smoke
600# Steam sytem pressure <560# triggers air purge
Condensate swept into GT23C
GT23B has 500lb/HR leakage on steam injection line- no condensate
Flameout
SPP is now at One Gas Turbine in Operation
600# Steam dropping 18 PSI/min [285#]
Loss of SPP Instrument Air
Excessive air leakage into GT23C?
Insufficient steam to operate
SD on high basket temperature
SPP Instrument Air drops 75# in 12 min
Poor Firing control low air pressure
SFR Total Steam Failure 600# at 130#; 150# at 80#
10/22/2010 2:37 PM
CWS Level 2
10/22/2010 3:05 PM
U240 plant Depressurizing to Flare 100 PSI/min
Media attention

ATTACHMENT 2

San Francisco Refinery 10/22/10 Shutdown
Event Summary

TIME	EVENT DESCRIPTION		
10:43 AM	Unit 120 Unscheduled Shutdown		
	Unit 120 Steam Production:		
	Time 10:43	600# St rate 126 Mlb/Hr	
		150# St rate 52 Mlb/Hr	
	+69 sec	600# St rate 200 Mlb/Hr	
		150# St rate 79 Mlb/Hr	
	+4min 42sec	600# and 150# down to Time 0 rate	
	+7min 53sec	600# St rate 21 Mlb/Hr, 150# St rate 52.2	
	13min 39sec	600# St rate 5.4 Mlb/Hr, 150# St rate 5.8 Mlb/Hr	
	SFR Fuel System Impact:		
	Time 0	G-425 Gas to U-120 14.0 MMSCF/D	
	+47 sec	G-425 Gas to U-102 Zero	
	Hydrogen Impact:		
	Time 0	102.8 MMSCF/D	
	+14 sec	0.0 MMSCF/D	
10:44 AM	SPP A-Turbine Shutdown		
	Alarms:		
	-13 sec:	PC168: COMP DIS PRESSU (High alarm at 240 psig)	
	Time 10:44	E110: N-01-10 Bus Vo (A Turbine Disconnects form Grid)	
		J1000: GRG-23A MEGAWA	
	+1sec	FC1015: GTG-231 NOX ST	
	+5sec	TI1102 -6: SOL 1 HT2 – 6 COMB 0 (Combustor Hi Temp SD)	
		J1001: GTG-23A MEGAVA	
	+12 sec	PC168: COMP DISCH PRESSU (Hi-Hi alarm at 279 psig)	
	+15 sec	SSL1012: TURBINE SHUTDW	
	Lost Steam Production: Unit 120 174 Mlb/Hr, A-Turbine 118 Mlb/Hr		
	STEAM CURTAILMENT ACTIONS IDENTIFIED		
	(+ Increased Production, - Cut Use)		
10:46 AM	Unit 240 Complex		-10 Mlb/Hr
10:47 AM	Unit 244 F-507		+10 Mlb/Hr
	Unit 240 Plant 1 B-102		+2 Mlb/Hr
10:48 AM	SPP GB-301/303 Air Compressor		-35 Mlb/Hr
10:57 AM	Unit 215 DI B		-26 Mlb/Hr
10:59 AM	Unit 231 Ref Splitter		-40 Mlb/Hr
	Total		123 Mlb/Hr
10:51:45	Refinery Air Header Normal: SPP:P918 119 psig, R100:PIC967A 114 psig		
10:53:00	Refinery Air Header: SPP:P918 112 psig, R100:PIC967A 114 psig		
10:56:13	Refinery Air Header: SPP:P918 100 psig, R100:PIC967A 102 psig		
11:04:51	Refinery Air Header Normal: SPP:P918 93 psig, R100:PIC967A 94 psig		
11:10:51	Refinery Air Header Fluctuates between 98 – 105 psig		

TIME	EVENT DESCRIPTION
	GB-301 and GB-303 shutdown. Electric Air Compressors at Sulfur Plant, Unit 228 and Unit 240 were operating. Unit 100 Electric Air Compressor was out-of-service.
11:00 AM	600# Steam Pressure at 400 psig 150# Steam Pressure at 155 psig
12:00 PM	600# Steam System holding at 450 – 500 psig 150# Steam System holding at 165 psig
	Refinery Air Pressure drops by 20 psig due to shutdown of GB-301 and GB-303
1:19 PM – 1:57 PM	SPP A Turbine started up and Coen Burners in service, did not get on to Electric Grid. 600# Steam System recovers to 600+
1:56:46 PM	600# Steam Pressure at 640 psig 150# Steam Pressure at 169 psig
1:57 PM	A-Turbine tripped by Electricians investigating why generator would not sync to Grid.
2:12 PM	SPP C-Turbine Shutdown Steam Injection Air Purge activated when steam system pressure restored to >560 psig. Condensate swept into Gas Turbine and shutdown when flames extinguished. B-Turbine continued to run due to Steam Injection leakage of 500 lb/Hr. Tri-Logger data confirms there were no Basket Temperature increases prior to the B-Turbine shutdown. C-Turbine Alarms: -38 sec PAL3043: Low Steam INJ PR (Reactivates after steam system pressure restored and the degrades) -28 sec PAL3043: Low Steam INJ PR Acknowledged -5 sec J3000: Generator MEGAWA (Generator output dropping) Time 2:12 E-310: N-03-10 Bus VO (C Turbine Disconnects form Grid) +4 sec XA3322: Shutdown Mode (cool down sequence)
	Steam System Impact
2:13:34 PM	600# Steam Pressure at 554 psig 150# Steam Pressure at 167 psig
2:27 PM	B-Turbine Shutdown:
2:28:52 PM	600# Steam Pressure at 285 psig (decrease rate 18 psi/min) 150# Steam Pressure at 91 psig
	NOTE: One Turbine Operation is not adequate to operate the Refinery, only safely shutdown. No Refinery actions to curtail steam usage or shutdown units until the last turbine shutdown. Unit cut reactor charge starting about 2:58 PM. Unicracker Reactors depressured at 100#/min, SIS low recycle gas flow, at about 3:05 PM. It takes 12 hours to liberate the hydrocarbon from the catalyst in the reactors. There was only 15 minutes between the C Gas Turbine and B Gas Turbine shutdowns which meant that if actions were taken to move oil from the unit there would be some minor advantage prior to the flaring.

TIME	EVENT DESCRIPTION
3:00:00 PM	600# Steam Pressure at 130 psig 150# Steam Pressure at 80 psig
	SPP Instrument Air System and Refinery Air Header
2:12:48	SPP Instrument Air Normal at 95 psig
2:14:26	SPP Instrument Air at 80 psig
2:16:20	SPP Instrument Air at 60 psig. P918 Instrument Air Header Low Pressure Alarm at 60 psig
2:16:49	SPP Instrument Air Header at 55 psig Refinery Air Header, SPP:P322, at 100 psig
2:19:14	SPP Instrument Air at 37.5 psig P918 Instrument Air Header Low-Low Pressure Alarm at 37.5 psig
2:24:23	SPP Instrument at 20 psig and holds at low pressure Refinery Air Header at 89 psig
2:27 PM	SPP B-Turbine Shutdown (Total SFR Steam Failure) Tri-Logger data confirmed all basket temperatures trending up and one basket temperature exceeded the 1650ºF shutdown temperature before all temperatures dropped suddenly. High Basket temperature shutdown B-turbine. B-Turbine Alarms -47 sec TSH2012 COMB LO SPREAD (cold basket) -18 sec TSH2012 COMB LO SPREAD -12 sec J2000: Generator MEGAWA (Generator output dropping) -4 sec J2000: Generator MEGAWA (Generator output dropping) Time 2:27 E-210: N-02-10 Bus VO (C Turbine Disconnects form Grid) +4 sec XA2322: Shutdown Mode (cool down sequence)
2:45:25	SPP Instrument Air at 15 psig Refinery Air Header at 78 psig
3:05 PM	Unicracker Reactors depressurized at 100#/min, SIS low recycle gas flow
3:34:41 PM	SPP Instrument Air Recovers to 61 psig Refinery Air Header at 84 psig

ATTACHMENT 3

San Francisco Refinery 10/22/10 Shutdown

Steam System Event Summary

TIME	EVENT DESCRIPTION		
10:43 AM	Unit 120 Unscheduled Shutdown		
	Unit 120 Steam Production:		
	10:43	600# St rate 126 Mlb/Hr	
		150# St rate 52 Mlb/Hr	
	10:44:09	600# St rate 200 Mlb/Hr	
		150# St rate 79 Mlb/Hr	
	10:47:42	600# and 150# down to Time 0 rate	
	10:50:53	600# St rate 21 Mlb/Hr, 150# St rate 52.2	
	10:56:39	600# St rate 5.4 Mlb/Hr, 150# St rate 5.8 Mlb/Hr	
10:44 AM	SPP A-Turbine Shutdown		

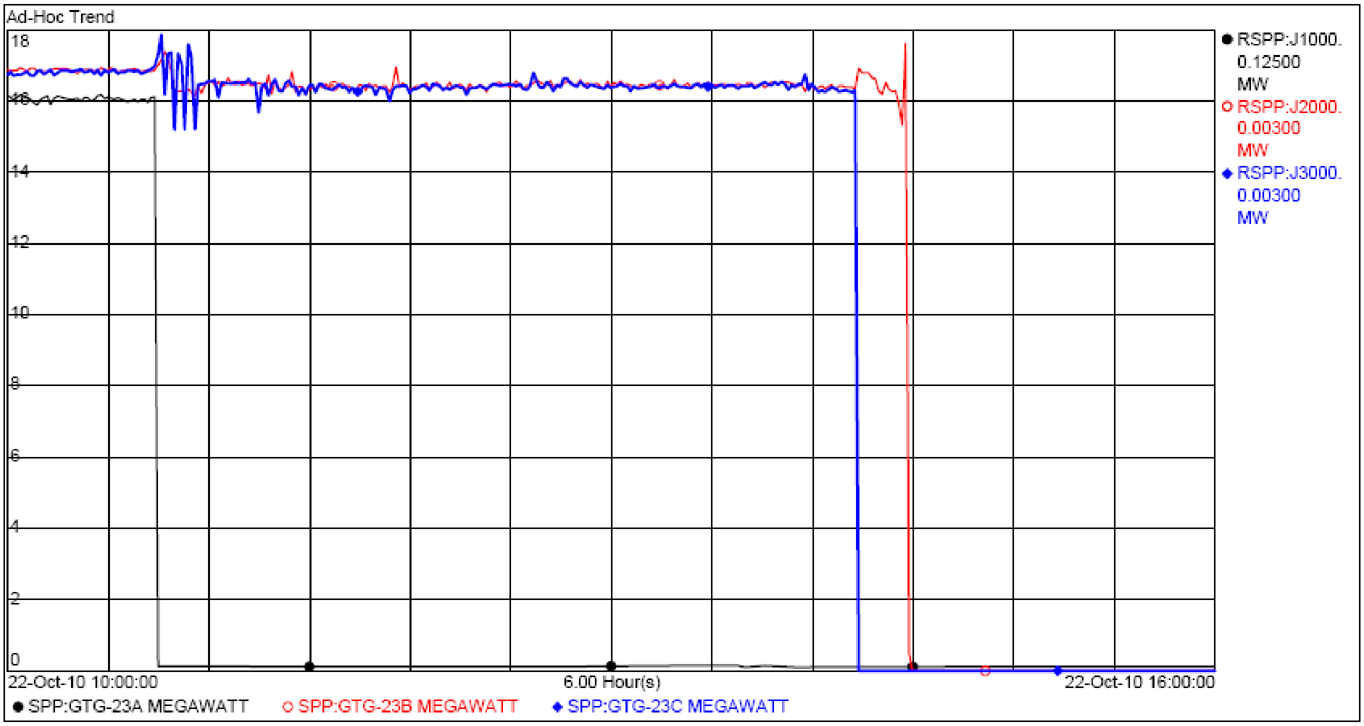
Lost Steam Production: Unit 120 178 Mlb/Hr, A-Turbine 118 Mlb/Hr

	STEAM CURTAILMENT ACTIONS IDENTIFIED (+ Increased Production, - Cut Use)	
10:46 AM	Unit 240 Complex	-10 Mlb/Hr
10:47 AM	Unit 244 F-507	+10 Mlb/Hr
	Unit 240 Plant 1 B-102	+2 Mlb/Hr
10:48 AM	SPP GB-301/303 Air Compressor	-35 Mlb/Hr
10:57 AM	Unit 215 DI B	-26 Mlb/Hr
10:59 AM	Unit 231 Ref Splitter	-40 Mlb/Hr
	Total	123 Mlb/Hr

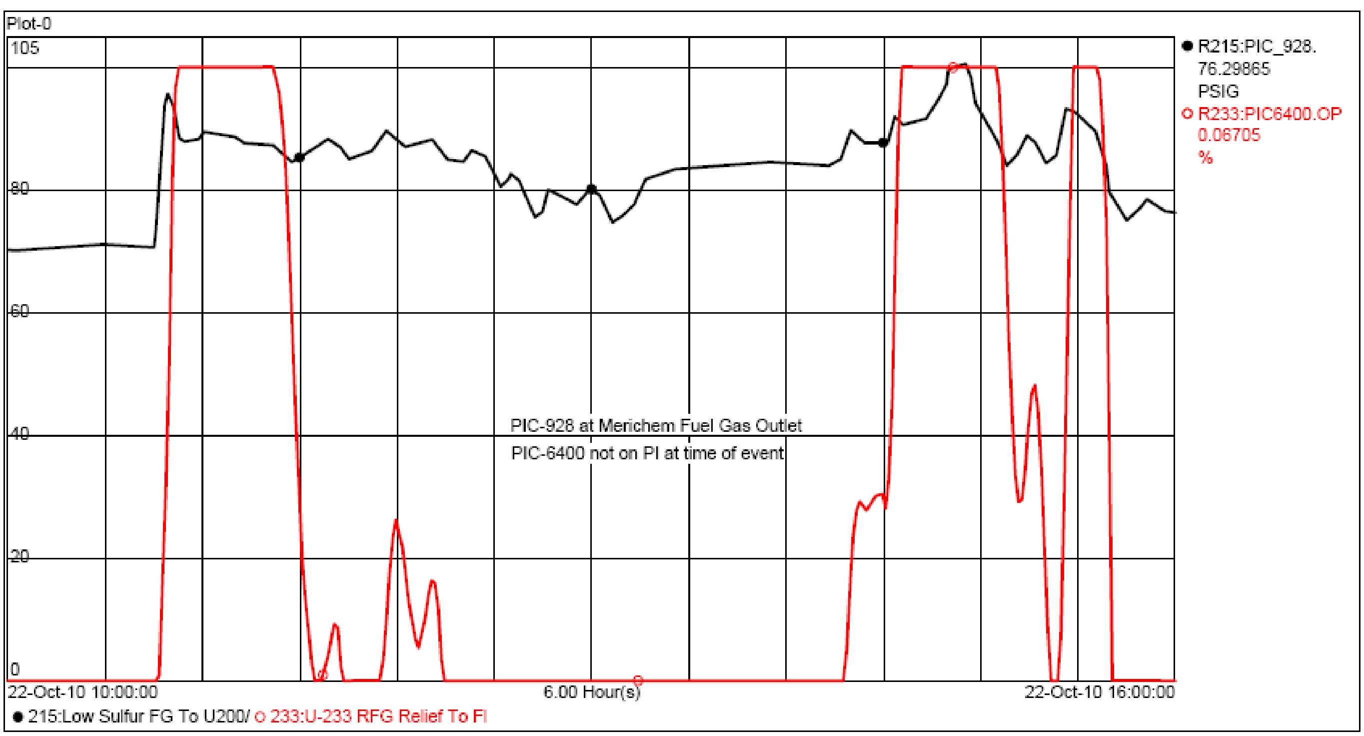
10:44 – 11:00 AM	600# Steam Pressure dropped from 616 psig to 400 psig 150# Steam Pressure dropped from 167 psig to 157 psig
11:00 – 11:30 AM	600# Steam Pressure increased from 400 psig to 600 psig 150# Steam Pressure increased from 157 psig to 167 psig
11:30 AM – 12:00 PM	600# Steam Pressure dropped from 600 psig to 480psig 150# Steam Pressure held at 165 psig
12:00 PM	600# Steam System holding at 450 – 500 psig 150# Steam System holding at 165 psig
1:19 PM – 1:57 PM	SPP A Turbine started up and Coen Burners in service. Did not get on to Grid. 600# Steam System recovers to 600+
1:56:46 PM	600# Steam Pressure at 640 psig 150# Steam Pressure at 169 psig
1:57 PM	A-Turbine tripped by Electricians investigating why generator would not sync to Grid.

TIME	**EVENT DESCRIPTION**
2:12 PM	SPP C-Turbine Shutdown
2:13:34 PM	600# Steam Pressure at 554 psig 150# Steam Pressure at 167 psig
2:27 PM	B-Turbine Shutdown:
2:28:52 PM	600# Steam Pressure at 285 psig (decrease rate 18 psi/min from 2:13:34 PM) 150# Steam Pressure at 91 psig
3:05 PM	600# Steam Pressure at 125 psig 150# Steam Pressure at 75 psig

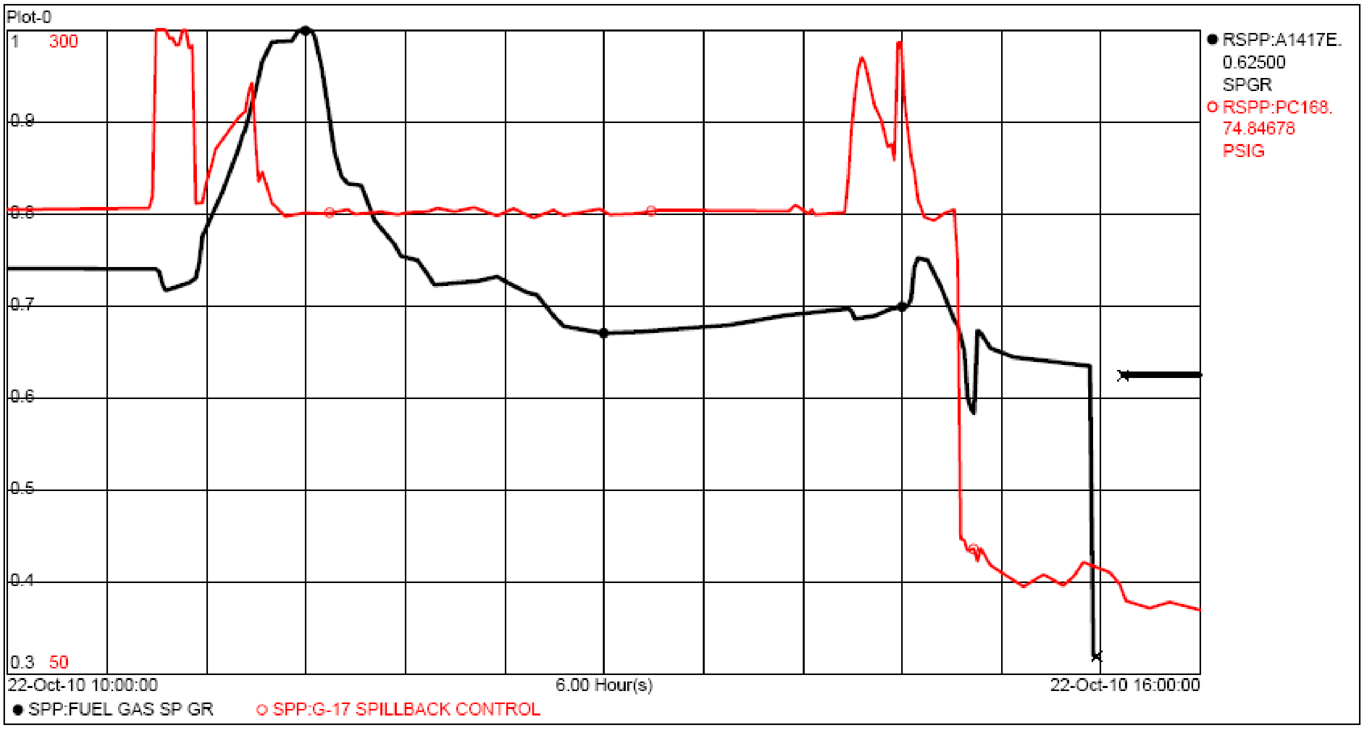
ATTACHMENT 4
Plant Instrumentation Trend Charts



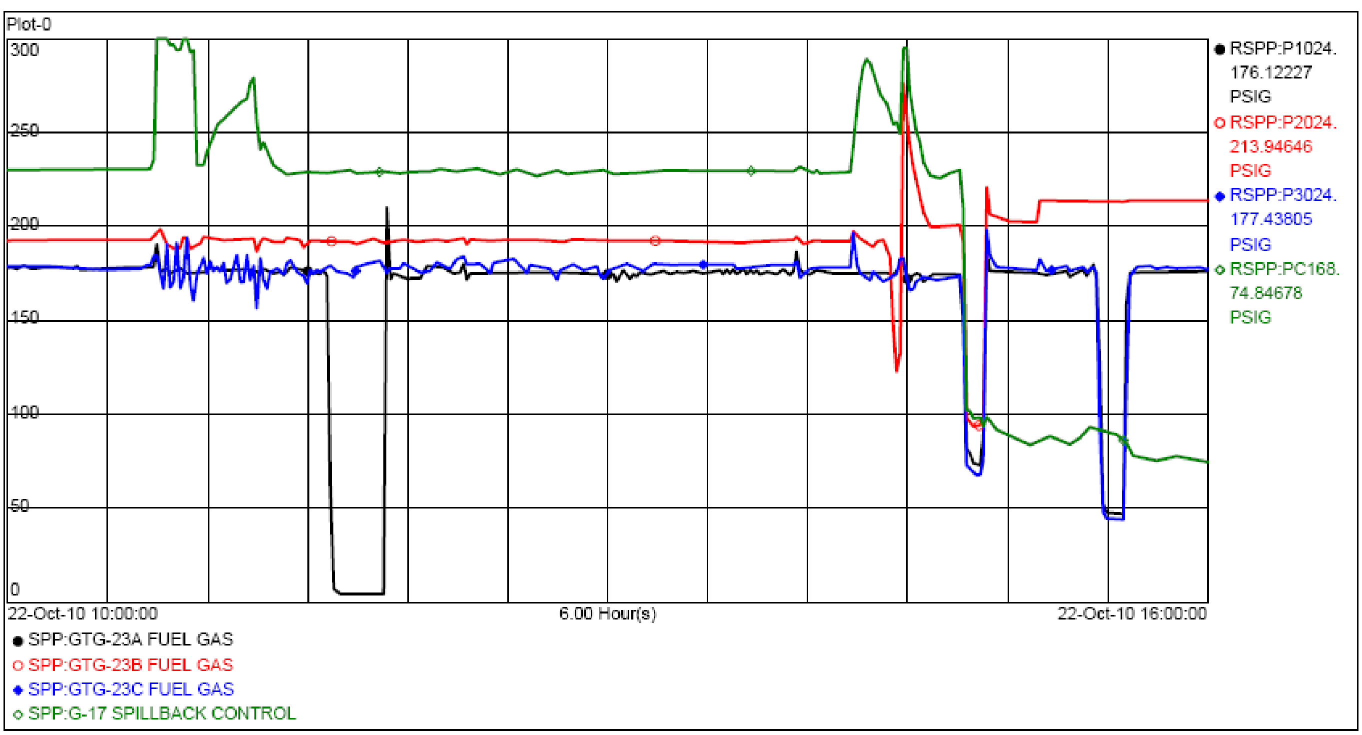
Steam Power Plant Turbine Power (Megawatt)



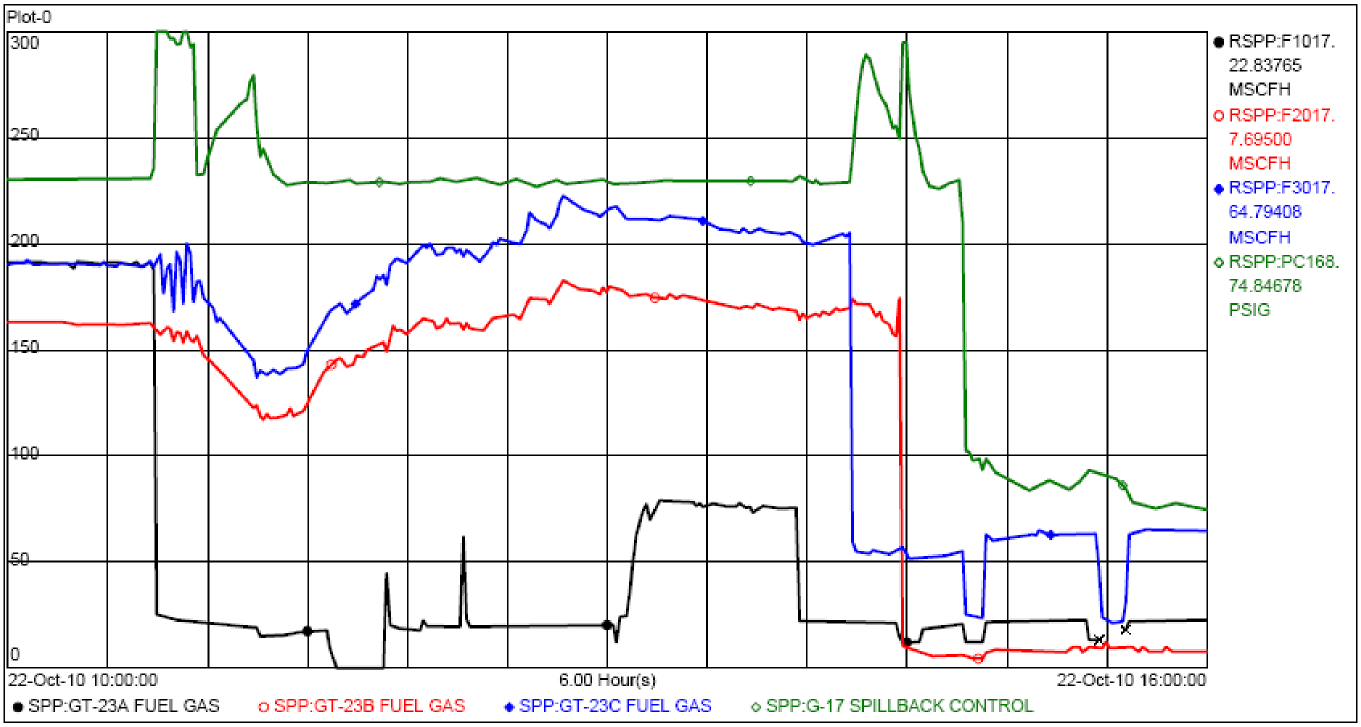
Refinery Fuel Gas Pressure & Relief to Flare Valve Position



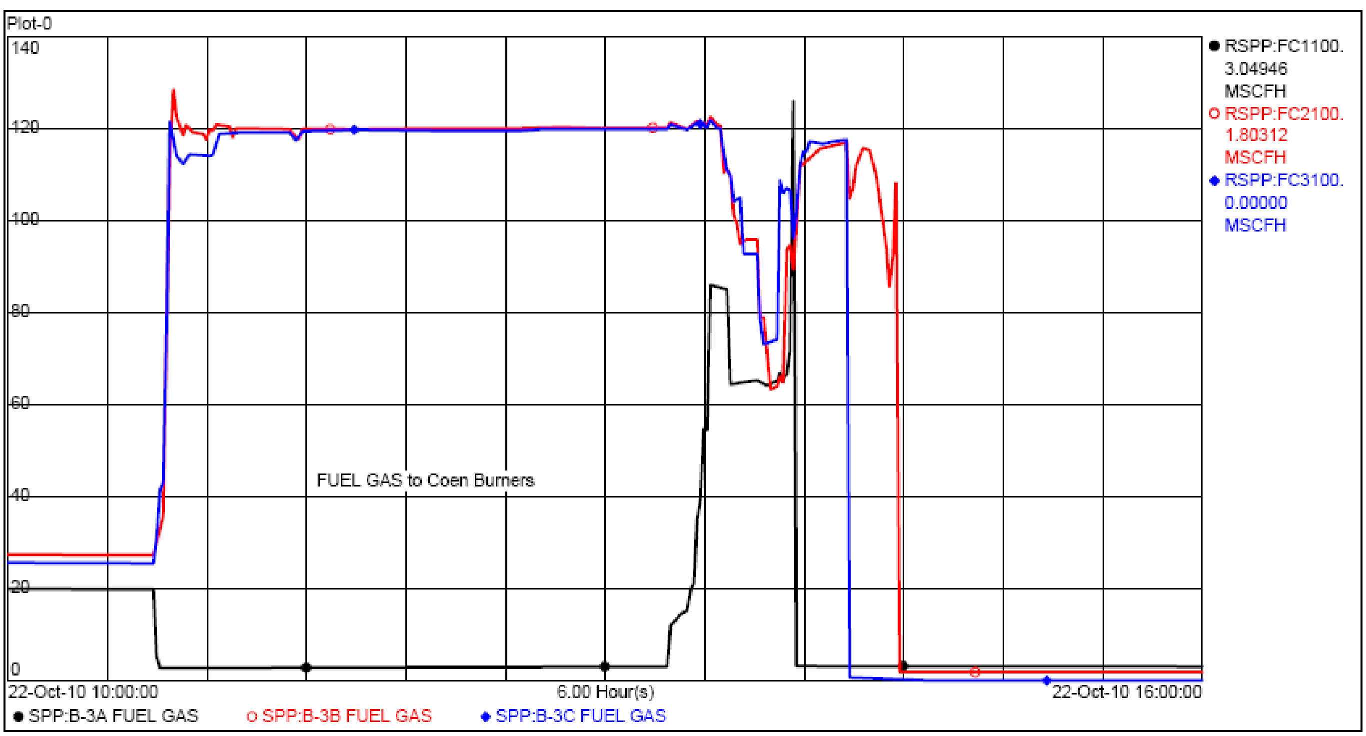
Steam Power Plant Turbine Fuel Gas Specific Gravity and Pressure



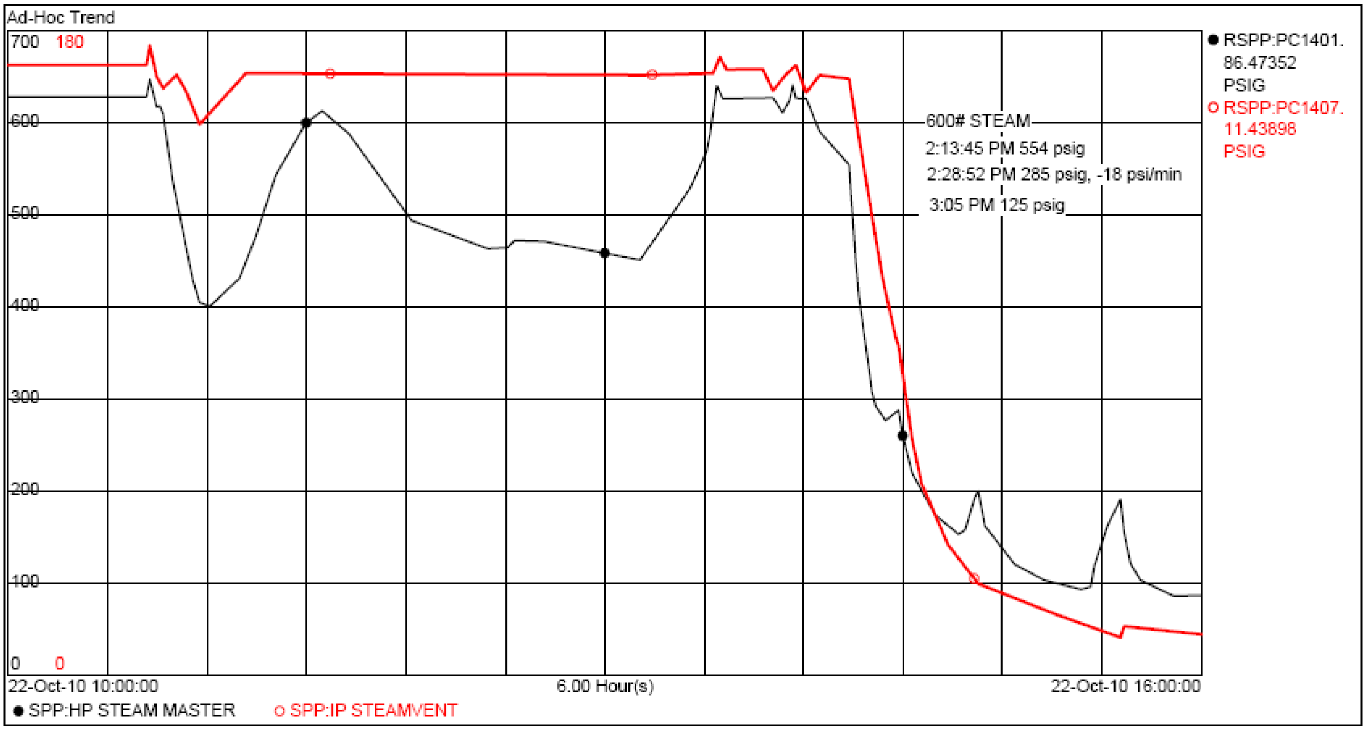
Steam Power Plant Turbine Fuel Gas Supplied Pressures A, B, and C versus Compressor Pressure



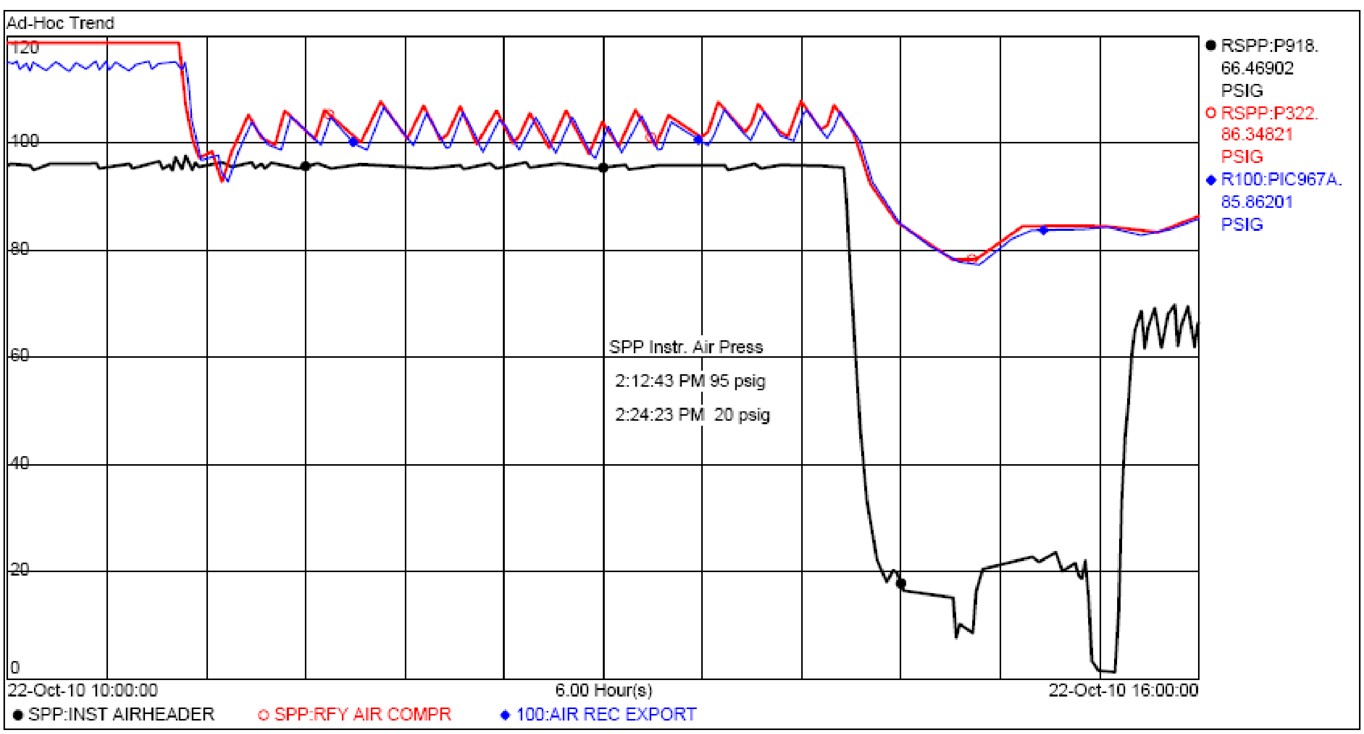
Steam Power Plant Turbine Fuel Gas Flow A, B, and C versus Compressor Pressure



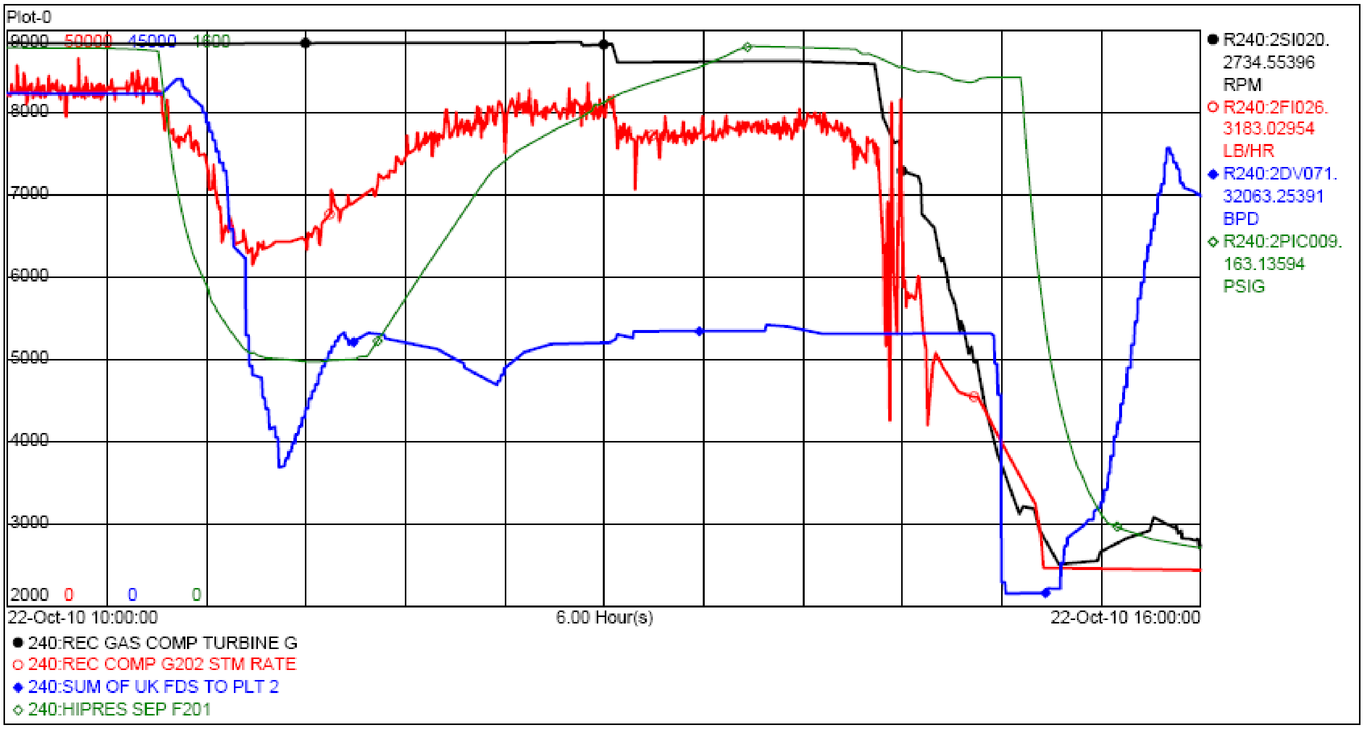
Steam Power Plant Fuel Gas Flow to COEN Duct Burners A, B, and C



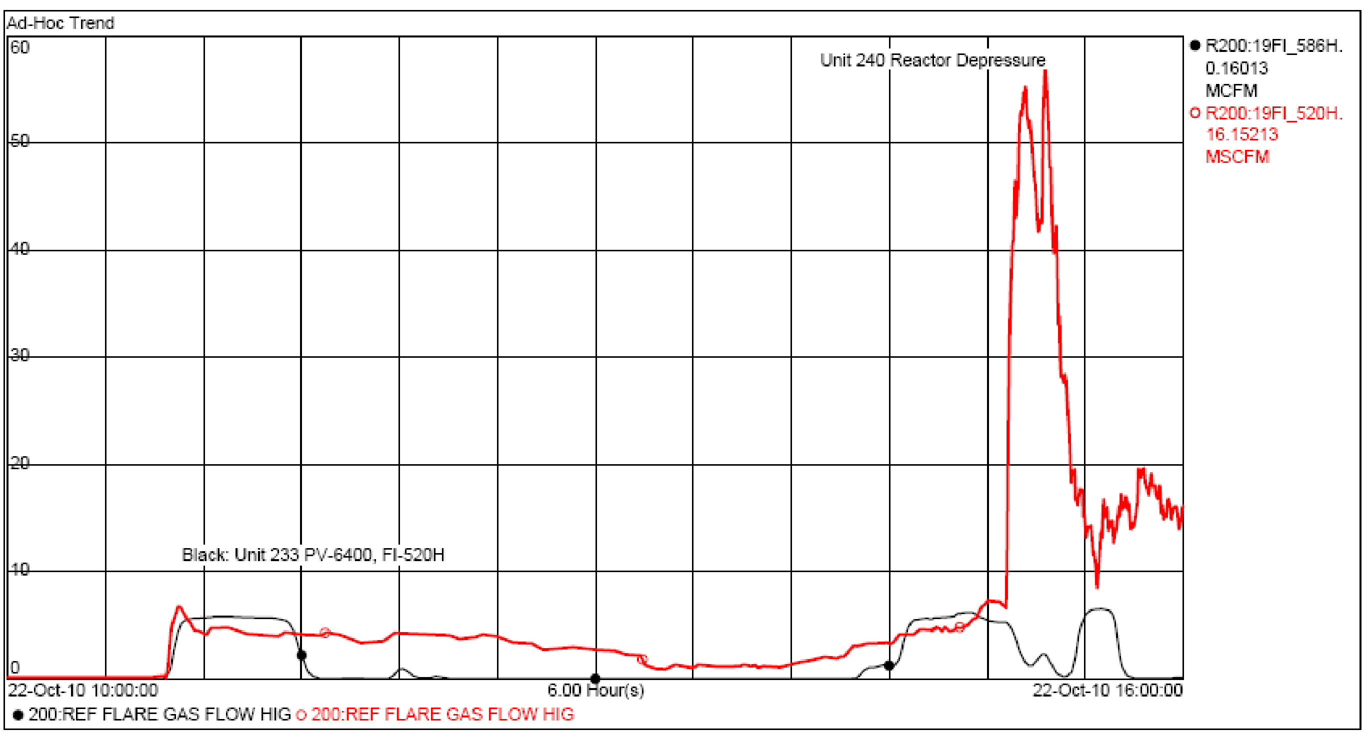
Steam System Pressure: 600# (High Pressure, HP) and 150# (Intermediate Pressure, IP)



Refinery Air Pressure versus Steam Power Plant Instrument Air Pressure



Unit 240 Recycle Gas Compressor RPM & Steam Rate versus Feed Rate & Pressure



Refinery Flaring Gas Flow Rates