



BP Cherry Point Refinery  
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June 25, 2008

Phyllis Baas, Section Manager  
Technical Services Section  
Air Quality Program  
Washington State Department of Ecology  
P. O. Box 47600  
Olympia, WA 98504-7600

**Re: Response to Questions and Issues Related to Cherry Point BART Technical Analysis Report**

Dear Ms. Baas:

I have enclosed a response to the list of questions and issues you provided on our BART Analysis on June 5<sup>th</sup>.

Please call Valerie Lagen at (360) 371-1443 if you have any questions or require additional information.

Sincerely,

  
Valerie Lagen  
BP Cherry Point Refinery

cc: Elizabeth Daly  
Maureen O'Brien

# Attachment 1

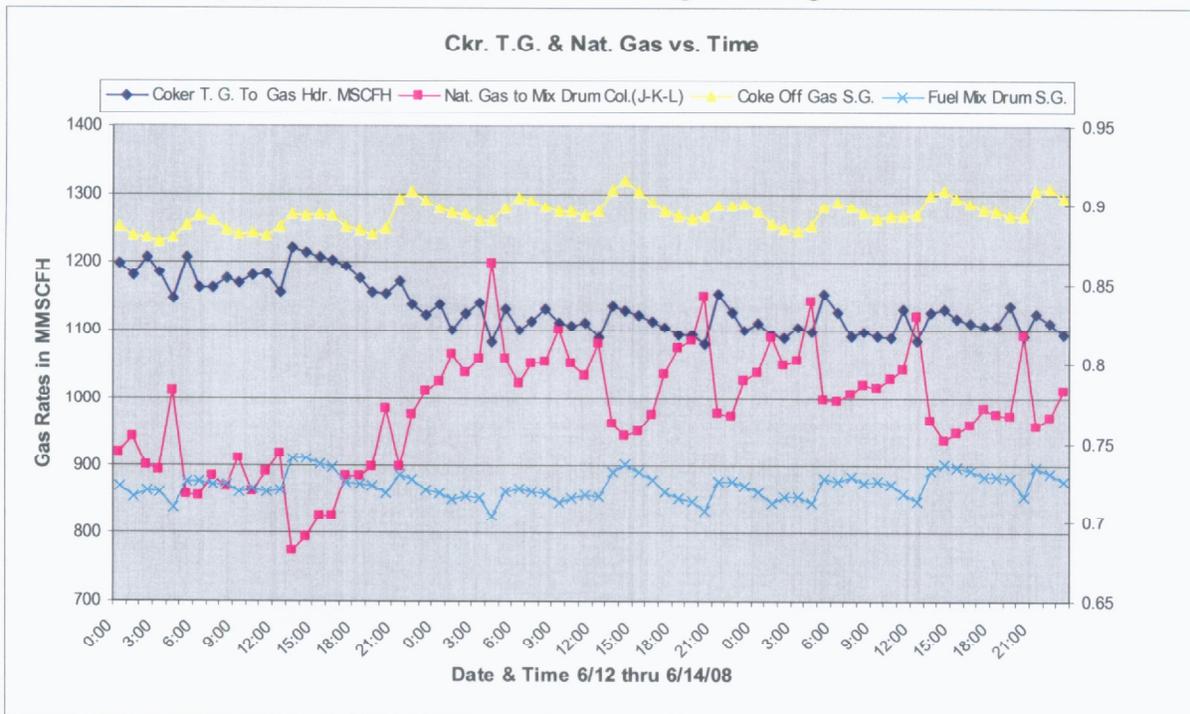
## Response to BP Cherry Point Refinery BART Analysis Questions

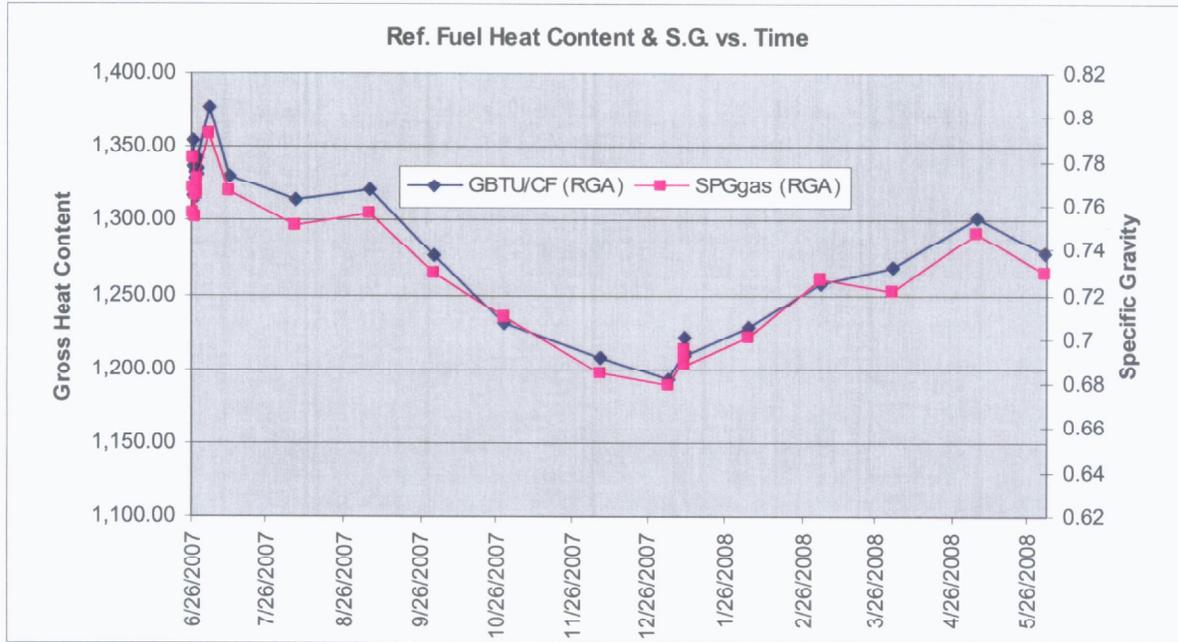
**Question 1:** BP has stated that the representative average /nominal heat content of the refinery gas used at the plant was 1,352 BTU/ft<sup>3</sup> (2003-2005 data), with an SO<sub>2</sub> emission factor of 0.0364 lb/MMBtu. Swings in refinery gas specific gravity (and heat content) are cited as affecting the viability of several BART options. We know that sulfur content can also vary. What is the range of refinery gas heat and sulfur contents, and how might the heat and sulfur content changes be described statistically over a day, week or year? What operations and refinery gas component variables drive these changes?

**Answer 1:** The refinery fuel consumption is affected by: throughput, crude blend, season, turnarounds, crude availability, Start-of-Run & End-of-Run on conversion units, hydrogen production/consumption, etc. "One off" predictions are impossible. Through all the swings, in normal operation, sulfur in fuel gas remains relatively constant, negligible in hydroprocessing units, and in the 500 ppm (total sulfur) range from the coker.

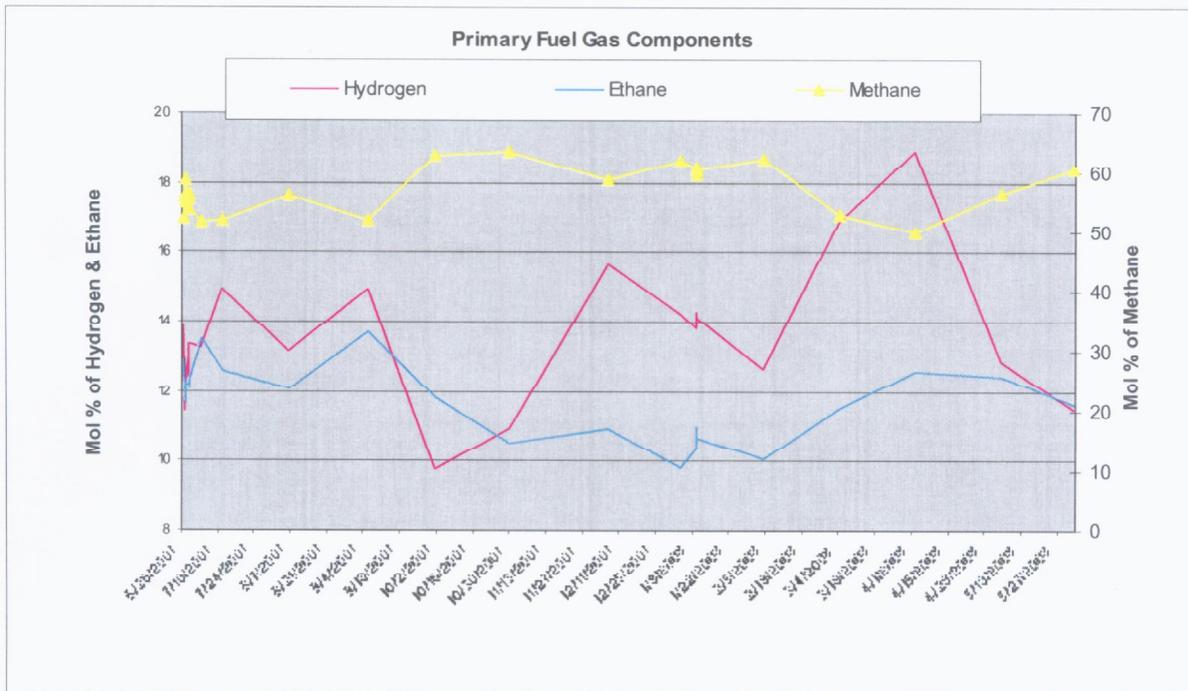
As shown in the graph below, the largest routine impact on heat content is the cyclic nature of the coker operation. Coker gas fluctuates cyclically with drum swings. Specific gravity (s.g.) of the fuel gas and coker gas is measured continuously and provides a correlation to the heat value of the gas. The impact of coker gas on imported natural gas is illustrated below along with the change in mix drum specific gravity (s.g.) with coker s.g.

The second graph shows that heat content and s.g. track together.





The final graph shows, for reference, the primary constituents of refinery gas.



**Question 2:** In multiple locations there is a discussion on the BART eligible Boilers 1 and 3 that discounts the need for reviewing controls for them. These discussions defer any need to analyze BART controls due to their future decommissioning and removal and replacement by new boilers. What is the project status of the replacement boiler project? Will the boilers be replaced by the end of 2010 as discussed in the report?

**Answer 2:** Boilers #6 and #7 are under construction now and are scheduled to be commissioned in the first quarter of 2009. Boilers 1 and 3 will be decommissioned no later than 12 months after commissioning of the first new boiler.

**Question 3:** Section 2.2 (page 6) Please provide additional discussion on your position that an add-on emission control device must meet the same time between maintenance shut-downs as the process heater it would control. The simple statement that a control (such as a dry scrubber for SO<sub>2</sub> control) does not exhibit this capability is not sufficient to classify the control as technically infeasible. For instance, use of a bypass stack might allow a heater to operate uncontrolled for the short time needed for control system maintenance. This would provide flue gas treatment for most of the year. During maintenance, emissions would be like they are now.

**Answer 3:** Section II. A. of the Washington State Regional Haze Guidance document states: "The visibility regulations define BART as follows:

Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by . . . [a BART-eligible source]."

This guidance in conjunction with a statement made by Ecology that we would not be required to derate or reduce the production of process units was the justification for this determination.

**Question 4:** Section 3 General. The opening paragraph of Section 3.0 (page 13) says that all process heaters and boilers are permitted to use a combination of natural gas and refinery gas. The sulfur emissions factors (Table A-1 SO<sub>2</sub>) for some heaters differ from others as a result of source testing of the different units. Why are the SO<sub>2</sub> emission factors for the source tested units higher than the emission factors based on refinery gas sulfur content monitoring? We note that the average of the three different source test emission factors (0.0432 lb/MMBtu) is about 18% higher than the mass balance factor of 0.0364.

**Answer 4:** In developing emission factors for refinery equipment we have used the best information available. In many cases this is a performance test. Sulfur dioxide emissions during source tests are based on fuel gas samples collected during the test and are only representative of that period of time. However, not all units have been recently source tested or in some cases, tested at all. Emission factors for these units are based on mass balance calculations using average sulfur properties from fuel samples collected over the previous three years. Samples are collected on a regular basis, but again are only representative of the

fuel gas at the time of collection. Variation in sulfur concentration is normal and to be expected. The Design Basis for the recently permitted boilers includes nine different fuel gas compositions to account for this variability.

**Question 5:** Section 3.1.1, Page 14. Please translate “burner’s performance with fuel gas gravity swings for units with high turndown”. Please confirm that ‘fuel gas gravity swings’ is jargon for changes in the specific gravity of the refinery gas and that the specific gravity of the refinery fuel gas related to the heat content of the gas? How does “high turndown” capability burner design affect performance and emissions?

**Answer 5:** “Fuel gas gravity swings” does refer to the changes in the specific gravity of the fuel gas which relates to the heat content of the gas. The need to design for this variability in the fuel gas composition impacts the flexibility of the burner design. The high methane content of a low SG fuel requires more inherent stability in the design which will then have an adverse affect on the NO<sub>x</sub> levels that can be achieved.

Similarly a high turndown requirement will also affect the achievable emission levels for the burner. Typically operation below 60% of the maximum firing rate of a burner will require higher excess air levels for complete combustion and low CO levels. These higher excess air levels will cause the corrected NO<sub>x</sub> emissions to increase.

**Question 6:** Please direct me to a reference or article discussing the importance of H<sub>2</sub> in the refinery fuel gas on the effectiveness of SNCR.

**Answer 6:** Selective Non Catalytic Reduction was eliminated for all combustion units based on flue gas temperature, not on H<sub>2</sub> in fuel gas.

**Question 7:** Page 15 and 17. Ecology appreciates that BP has proposed installation of a ULNB on the 1<sup>st</sup> Stage HC Fractionator Reboiler. For completeness of the analysis and to support our ultimate BART determination, please explain what characteristics of this heater make it conducive to the steam injection and burner modifications that don’t exist in other units (those without LNB or ULNB already installed) where steam injection, burner modifications are rejected as technically infeasible.

**Answer 7:** The primary factor in determining that the 1<sup>st</sup> Stage HC Fractionation Reboiler could support steam injection or possible burner modifications is that this heater has no historical operational problems where many of the others are currently dealing with some form of operational concern such as high heat density and long flames occasionally resulting in flame impingement on the process tubes.

Since the current burners have good stability and BP has had some level of positive experience with steam injection on this type of burners it was considered to be a viable option.

Modifications to the burner tip drillings to optimize the emissions was also thought to be a possibility as the existing burners are already a staged fuel design with good stability. Improvement to the NO<sub>x</sub> emissions however was expected to be minor.

**Question 8:** Section 3.1.3, Page 18. Please support the 5 ppm control effectiveness statement for SCR. Our experience with SCR and the literature on other industries use of SCR does not support the statement that SCR cannot reduce NO<sub>x</sub> below 5ppm. Current generation large combined cycle combustion turbine facilities are routinely permitted with NO<sub>x</sub> limits of 2 ppm with a 9 ppm uncontrolled emission rate. The 5 ppm SCR control effectiveness is used several places, including the Diesel HDS Charger Heater & Diesel HDS Stabilizer Reboiler on Page 28, and the Steam Reforming Furnaces #1 and #2 on page 29.

**Answer 8:** The criteria we used for SCR NO<sub>x</sub> effectiveness was based on conversations with catalyst vendors and was based on 95% reduction or 5 ppm NO<sub>x</sub>, whichever was higher. Increasing the SCR efficiency above 95% requires exponentially higher catalyst volume and associated cost. Higher efficiency would have resulted in increased control costs (\$/ton).

**Question 9:** Section 3.1.4.1, Page 25. Please provide more detail on why LNB doesn't work on this unit beyond "high heat density". What concept is 'high heat density' supposed to convey? This is only important due to your citing it as a reason why LNB is not feasible or BART.

**Answer 9:** Heat Density is an industry accepted criteria for predicting LNB or ULNB performance when installed in a process heater and is equal to the total firing rate (LHV) divided by the heater cross sectional area. This metric is based on empirical data and was developed by the burner industry in response to many LNB and ULNB installations in which the field performance was significantly worse than that seen on the test heaters. The generally accepted maximum heat density threshold for new heaters is 250,000 Btu/ sq ft-hr and for retrofits up to 350,000 Btu/sq ft-hr.

For vertical cylindrical heaters such as the Crude Heater the cross sectional area is equal to the area bounded by the radiant tubes. This results in a heat density of over 470,000 Btu/sq ft-hr for the Crude Heater which is well above the acceptance criteria for LN or ULN burner installation.

Cherry Point has had first hand experience with the affects of attempting a burner retrofit on a heater with heat density above the recommended acceptable limit. In 1999, before the concept of heat density had been developed, Cherry Point's South Vacuum Heater was retrofitted with ULNB. The South Vacuum Heater has a heat density of around 410,000 Btu/sq ft-hr and the burner retrofit did not perform as well as predicted by the burner vendor. After many years of struggling with the resulting flame impingement and marginal NO<sub>x</sub> performance that ultimately required the heater duty to be restricted, the burners were replaced. By implementing many additional heater modifications in addition to the new burners, and spending months of troubleshooting and burner optimization the new burners have been made to work but with only marginal performance in terms of both emissions and flame quality.

**Question 10:** Section 3.1.4.5, Page 27. What is the alternate fuel source which “limits the effectiveness of NO<sub>x</sub> control technologies?” Earlier in this report you imply that all burners are fueled with natural gas or refinery gas (and maybe both). No alternative fuel usage is noted elsewhere in the report.

**Answer 10:** This section refers to the coker heaters which burn coker fuel gas as described in Answer 1. All other combustion units burn refinery fuel gas (including supplemental natural gas) from the mix drum.

**Question 11:** Section 3.2.4, page 35. Statement that fuel gas conditioning to reduce sulfur will add 1 ton/day to the existing SRU loading. What change in concentration of sulfur compounds in the fuel gas does this 1 ton/day represent? If 50 ppmv (the gas compound is not clear, total S? H<sub>2</sub>S? COS?) represents 89% reduction, this implies the original fuel gas had 454 ppmv of total sulfur compounds.

Can fuel gas containing 50 ppm total sulfur be attained today without additional expense on new equipment? What changes would be needed to assure a 50 ppm refinery gas sulfur limit can be achieved.

**Answer 11:** Refinery fuel gas is composed of three streams as shown below: amine treated coker fuel gas containing on average 500 ppm of sulfur compounds, imported natural gas (beyond gas used for pilots) and amine treated refinery gas from the various refinery hydrotreating and hydrocracking units.

Source	Volume, MMSCFH	percent
Coker Fuel Gas to BART furnaces	1.1	44%
Natural Gas Import	0.8	32%
Refinery Fuel Gas	0.6	24%
Total	2.5	100%

Total Sulfur in the Coker Fuel Gas Stream

(1.3 MMSCFH * 511/MMSCFH)/379 =	1.48	mols/h of S
mols/h * 32 * 24 =	1139	lbs.
1421/2240 =	0.51	LTD

Samples from March 16, 2008 Sample Name	(K) Coker Fuel Gas	Average	%			
Time	12:32	13:48	15:05	15:30		
H2S	6	6	4	6	6	1%
COS	58	57	46	60	55	11%

R1SH	333	301	411	274	330	65%
R2SH	105	110	96	104	104	20%
Thiophene	nd	nd	nd	nd	0	0%
DMS	4	4	3	4	4	1%
R3SH	6	7	7	12	8	2%
MES	nd	nd	nd	nd	0	0%
R4SH	5	6	3	4	5	1%
MES	nd	nd	nd	nd	0	0%
DMDS	nd	nd	nd	nd	0	0%
R5SH	nd	nd	nd	nd	0	0%
R6SH	nd	nd	nd	nd	0	0%
Total Sulfur	517	491	570	464	511	100%

Note that these samples were taken AFTER existing amine treating facilities and that H<sub>2</sub>S, R1 and R2 mercaptans have been significantly reduced at this point. A linear blending with the remaining refinery fuel gas streams (assuming sulfur in these streams is ~0.0 – ignoring the units amine treaters are not 100% effective) indicates that without further treating total sulfur in refinery fuel gas is 246 ppm total sulfur.

Total fuel gas sulfur to the coker furnaces, sent “neat” from the coker treater is 511 ppm. Volumetrically, the coker furnaces consume ~15% of the coker fuel gas “make”. That is to say, if the flow to the refinery fuel gas mix drum is 1.1 MMSCFH, total coker fuel gas is ~1.3 MMSCFH. That is the total flow thru the coker amine treating system.

Can fuel gas containing 50 ppmv total sulfur be attained today without additional expense on new equipment? What changes would be needed to assure a 50 ppm refinery gas sulfur limit can be achieved?

The above calculation shows a <50ppm total sulfur stream is not possible without further treatment. To achieve the <50 level, multiple technologies could be required. Conventional mercaptan removal involves caustic treating followed by lean oil absorption. System on-stream factor is then determined by the lean oil source – this also creates a negative opportunity to contaminate hydrotreating catalyst with caustic. If 90% effective the combined R1SH + R2SH would be approximately 45ppm. COS removal is a completely separate technology. Without COS treating minimum total sulfur is 118 ppm and the blended fuel gas ~55 to 60ppm.

**Question 12:** Section 3.2.4.1, page 36. Please explain how the cost per ton of fuel gas conditioning was obtained. What new equipment, chemical costs, energy costs are required for fuel gas conditioning? Is cost of fuel gas conditioning (\$22,282/ton SO<sub>2</sub>) split by SO<sub>2</sub> reduction the same as a split based on fuel consumption? It is intuitive that total project cost divided by the total tons of sulfur compound reduced is the most logical measure. It is not clear if all of the project cost was assigned to the BART units, or if costs were distributed over all refinery gas using heaters and boilers at the plant.

**Answer 12:**

A process study was performed, with 8 different process options evaluated. A process flow diagram, equipment list and cost estimate were made for each option. The cost estimate for the leading option, Lean Oil Absorption, was used for the BART analysis.

A process flow diagram and equipment list for the Lean Oil Absorption option are attached. The energy and chemical costs were included in the operating costs which were based on 1 ½ percent of the Total Installed Cost (TIC). The maintenance costs were based on 3 ½ percent of the TIC.

The cost of fuel gas conditioning split by SO<sub>2</sub> reduction is not the same as a split based on fuel consumption. As noted by your question 4, the SO<sub>2</sub> emission factors are not the same for all of the heaters. If we use the fuel consumption (based on heater design rates) to split the costs the \$/ton will vary from \$18,986/ton to \$30,912/ton.

The costs of fuel gas conditioning were assigned to just the BART units.

**Question 13:** Section 3.3.2, Page 39. You discount the use of a baghouse for increased particulate control. One reason is the length of time necessary to coat the bags with a thick enough dust cover to be effective. Is it possible, and what would the additional cost be to include precoating the bags with a chemical dust like sodium bicarbonate or calcium oxide?

It is assumed that particles from gas consumption are all less than PM<sub>2.5</sub>, and most are less than PM 1.0. Can a bag filter trap these sizes without a large pressure drop across the specially coated or designed bag?

**Answer 13:** According to the “Midwest Regional Planning Organization (RPO) Petroleum Refinery Best Available Retrofit Technology (BART) Engineering Analysis” states that “The cost per ton PM removed is very high for boilers and process heaters; therefore MACTEC did not include any controls for these units.” Cost of particulate controls considered for oil fired heaters (Cherry Point has no oil fired heaters) are shown below:

Control Technology	Cost of Control (\$/Ton PM)
Wet ESP	111,479 – 299,485
Dry ESP	15,692 – 132,599
Fabric Filters	59,613 – 120,162

The cost per ton PM removal would be significantly higher for gas fired units.

**Question 14:** Section 4.0, page 46. For our support document we will need some additional detail on the flare operation. Is the flare used only in emergencies, or are some gases from normal operations flared also? What happens to the coker blowdown gas if the equipment involved with collecting the coker blowdown becomes inoperable? Are they directed back to the flare? Has coker blowdown gas had to be directed to the flare due to a failure of the coker blowdown gas collection system?

**Answer 14:** The flare is used only for emergencies for all operating units. All gases to the flare, including coker gas go through the flare gas recovery system where condensable liquids can be recovered and the gas amine treated to remove H<sub>2</sub>S.

The coker, being a semi-batch process, has changes in gas flow when hot vapors are diverted from a full to an empty drum to heat the drum prior to putting it in service. After the heat-up is complete the “full” drum is taken off-line, de-pressured and cooled before the coke is cut from the drum. During these “drum swings”, an automated control scheme diverts flow from the flare gas recovery system to the Coker Blowdown Vapor Recovery system. While the recently filled coke drum is being de-pressured and cooled, the CBVR system routes the coker blowdown gases back to the coker wet gas compressor keeping hydrocarbons within the coker gas treating system. When the coke drum is cooled to the point where the coke has been stripped of hydrocarbon and the vapor stream is essentially steam, the CBVR system re-routes the stream back to the flare gas recovery system. The result is that negligible hydrocarbons are routed to the flare.

As mentioned, the system is highly automated. Part of the complexity results from having 4 drums in service and cycle times. During the warm-up and cool down, pressure and temperature controls automatically divert flows. Consequently, it is the sequencing, rather than the equipment, that is more likely to result in hydrocarbon to the flare. Upsets in sequencing can be from a leak, or preparing a furnace for maintenance. In these cases both flare gas recovery compressors are put into service to maximize coker gas recovery; however, the equipment may not handle the maximum flows for short durations resulting in some flow to the flare.

In the 27 months since the coker blowdown vapor recovery project has been in place, the system has only been offline for 4 blowdown cycles for a total of 16 hours. During that time, vapors were routed to the flare gas recovery system for capture into the fuel gas system.

**Question 15:** Section 5.1.2, page 50. What is importance of the burner being a “side entering” burner rather than some other orientation? Is this simply a statement that the burner is on the long side of the firebox firing across the width of the firebox rather than the long direction?

**Answer 15:** In the paragraph, LNB in SRU Process, the description “side entering” means exactly that, the burner flame is across the furnace rather than aimed down the length of the furnace. More importantly, in this section of the furnace, ammonia from “dirty” acid gas is combusted with oxygen and hydrogen sulfide at about 2400 °F to produce elemental nitrogen, sulfur dioxide and water. There are no LNB’s in this service. The SO<sub>2</sub> formed is reacted with H<sub>2</sub>S over catalyst to form elemental sulfur in the classic Claus reaction.

**Question 16:** Concerning Appendix A, Baseline Emissions

**Question 16.1:** Similarly to Question #4, what is the refinery gas total sulfur content (ppm of sulfur in the refinery gas) used for the baseline emissions, and how does that sulfur content

compare to natural gas? Is this refinery fuel gas sulfur content measured before or after blending with natural gas? Is there any blending with natural gas? If the measurement is after mixing of refinery gas and natural gases, what is the annual split between refinery fuel gas and natural gas use?

**Answer 16.1:** As shown in Answer 11, the total sulfur content of refinery fuel gas at Cherry Point is on average 246 ppm but can range up to over 500 ppm. A conservative value of approximately 400 ppm was used for this analysis. Information provided by Cascade Natural Gas indicates that natural gas contains approximately 4 ppm sulfur after odorant is added.

**Question 16.2:** Do any units burn fuels other than natural gas or refinery gas?

**Answer 16.2:** The coker heaters are unique at the refinery in that they burn gas generated in the coker process unit. The gas that is not consumed in the coker heaters is routed to the refinery mix drum. The refinery mix drum receives gases from a number of process units including the coker. Natural gas is added as needed at the mix drum to provide the energy needs of the refinery. This combined stream is referred to as refinery fuel gas. All gas generated at the refinery, including that from the coker is considered refinery fuel gas and subject to the New Source Performance Standards for Refineries (NSPS Subpart J/Ja.)

**Question 16.3:** Which BART units (if any) burn gas streams that contain nitrogen compounds like ammonia or amine?

**Answer 16.3:** The main reaction furnace of the Claus sulfur plant is capable of burning gas containing ammonia or amine.

**Question 17:** In Table A-1, please provide additional information on why some units have different SO<sub>2</sub> emissions factors. i.e. why some units have an emission factor based on a mass balance from the refinery gas total sulfur content and some have higher emission factors based on source tests.

**Answer 17:** See Answer 4.

**Question 18:** Why are the source test based emission factors higher than the mass balance factor?

**Answer 18:** Natural variability of sulfur compounds in fuel gas analyzed during performance tests and routine fuel gas analysis.

**BP CHERRY POINT REFINERY  
FUEL GAS CONDITIONING  
OPTION 3  
LEAN OIL ABSORPTION WITH CAUSTIC TREATING  
PROCESS DESCRIPTION**

This option first uses caustic to remove light mercaptans from the sour fuel gas streams. The unit processes 26.9 MM SCFD of sour Coker Off Gas and Vacuum Tail Gas which are oxygen free. Also, 2.8 MM SCFD of Recovered Flare Gas which contains oxygen must be treated. Oxygen limits the effectiveness of using a regenerated caustic for scrubbing.

The Coker Off Gas, Vacuum Tail Gas and Recovered Flare Gas streams are contacted with a regenerated caustic in Fiber Film Contactor V-5. Light mercaptans react with caustic to form sodium mercaptides. Caustic and gas are separated in Phase Separator V-6. The caustic scrubbed gas is subsequently lean oil treated. Caustic from V-6 is heated to 125 °F by steam in E-3 and fed to Oxidizer Tower T-2. Air is injected into T-2 to convert the mercaptides to disulfide oil (DSO). This reaction is enhanced by the presence of oxidizing catalyst which is circulated with the regenerated caustic. Air from the Oxidizer Tower is sent to the TGU incinerator for disposal. Trace sulfur compounds present in this air stream would otherwise pose an odor emission problem. Caustic and DSO from the Oxidizer Tower flow to Caustic/DSO Separator V-10 where the oil phase separates from the aqueous caustic stream. A circulating naphtha is used to enhance removal of entrained DSO from the regenerated caustic. Otherwise the entrained DSO will "re-enter" the treated fuel gas stream. Fiber Film Contactor V-9 is used to promote this de-entrainment. As caustic strength and alkalinity are reduced in this operation, spent caustic is removed batch-wise and replaced with fresh caustic to maintain caustic inventory in V-10.

The caustic treated gases are compressed to 140 psig and fed to COS Hydrolysis Reactor R-1. COS present in the gas stream reacts with water to form H<sub>2</sub>S and CO<sub>2</sub>. Water for reaction is provided by steam injection into the compressed gas stream. R-1 effluent is cooled to 100 °F in E-1. Any condensed sour water is collected in knockout drum V-2. COS free gas from V-2 is fed to the 28 tray Lean Oil Absorber Column, T-1. The lower 21 trays of T-1 use naphtha to remove the bulk of the heavy mercaptans, sulfides and disulfides contained in the sour fuel gas stream. 3000 BPD of sour NHT feed naphtha is introduced at tray 8 to absorb most of the sulfur compounds from the fuel gas stream. The upper 7 trays of T-1 use 1000 BPD of sweet naphtha from the NHT to remove the remaining heavy mercaptans, sulfides and disulfides from the gas stream. Using sour naphtha for the bulk sulfur removal in T-1 reduces the amount of treated naphtha that must be recycled to the NHT unit. Sour naphtha from the bottom of T-1 is pumped to the NHT where the absorbed sulfur compounds are converted to H<sub>2</sub>S. Fuel gas from T-1 contains sufficient H<sub>2</sub>S so that it exceeds the target TRS limit. This gas must be amine treated to meet required TRS specification. The gas is first cooled to 100 °F in E-2 and then fed to the 20 tray Amine Contactor T-3, where the H<sub>2</sub>S produced in R-1 is removed. 30 gpm of lean MDEA is fed to the top tray of T-3. The amine removes sufficient H<sub>2</sub>S to produce a treated fuel gas that meets the target 40 ppmv maximum TRS. The treated fuel gas exits T-3 and the unit at 115 psig. Rich amine from the bottom of T-3 is directed to the amine regenerator at the Sulfur Recovery Unit.



