United States Environmental Protection Agency

Region 6 Compliance Assurance and Enforcement Division
INSPECTION REPORT

Inspection Date(s):	3/28-30/2016		
Media:	Air		
Regulatory Program(s)	Consent Decree, Civil Action H-01-0978		
Company Name:	**Motiva Enterprises LLC**		
Facility Name:	**Motiva Enterprises LLC Port Arthur Refinery**		
Facility Physical Location:	2555 Savannah Ave.		
(city, state, zip code)	Port Arthur, TX 77460		
Mailing address:	P.O. Box 712		
(city, state, zip code)	Port Arthur, TX 77460		
County/Parish:	Jefferson County		
Facility Contact:	Damian Fryoux	Environmental Manager	
	Damian.fryoux@Motivaent.com		
FRS Number:	110000464024		
Identification/Permit Number:	O-01386		
Media Number:	AFS # 4824500020		
NAICS:	324110		
SIC:	2911		
Facility Representatives:	Damian Fryoux	Environmental Manager	504/275-8782
EPA Inspectors:	Jim Gold	Region 6, 6EN-ASH	281/983-2153
	Prince Nfodzo	Region 6, 6EN-AA	214/665-7491
State Inspector(s):	Did not attend		
Other Inspector(s):	NA		
Metadata — Title:	Motiva Refining, Port Arthur Refinery, Port Arthur, Texas, Jefferson County		
Metadata — Author:	US EPA Region 6 Compliance Assurance and Enforcement Division Dallas TX		
Metadata — Subject:	Partial Compliance Evaluation Inspection Report		
Metadata — Keywords:	refinery consent decree (CD)		
EPA Lead Inspector Signature/Date	Jim Gold Jim Gold		Date 4/27/2016
Supervisor Signature/Date	Sam Tates Samuel Tates		5/12/2016 Date

Motiva Enterprises LLC, Port Arthur Refinery
3/28-30/2016

Section I - INTRODUCTION

PURPOSE OF THE INSPECTION

EPA Region 6 inspectors Prince Nfodzo and I (Jim Gold) conducted an inspection of the Motiva Enterprises LLC Port Arthur, Texas Refinery. At 1:00 pm on March 28, 2016, we met with Damian Fryoux, Environmental Manager for the facility, for an opening conference. We presented our credentials to Mr. Fryoux and informed him that this was an EPA inspection to determine compliance with the federally issued Consent Decree (Civil Action H-01-0978), which is a national priority for EPA. The inspection was a Partial Compliance Evaluation (PCE), which included an evaluation of the consent decree's (CD) four marquee issues: nitrogen oxides and sulfur dioxide (NO_x/SO_2) reductions, leak detection and repair (LDAR), benzene waste operations (BWON) and flaring of both acid gases and hydrocarbons.

The CD consists of 19 Parts designated by Roman numerals. Of these, Parts IV - VIII requires affirmative relief, which was the focus of the inspection. These Parts address the requirements of NO_x,SO_2, CO, particulate, VOC, and benzene emission reductions through various construction projects, process additives, and process and program enhancements.

The applicable consent decree (H-01-0978) originally entered August 21, 2001 most recently was amended January 19, 2006 to remove conditions pertaining to heaters and boilers and referred to as "the heater and boiler CD". The heaters and boilers CD was previously terminated and therefore heaters and boilers were not part of this inspection.

Note that these inspection findings pertain only to the compliance status affecting Motiva's Port Arthur refinery. Photos taken during the inspection (11) are included as **Appendix 1**. Note that the date stamp shown in the photos is dated 1/1/2012. The actual dates of the photographs are 3/29/2016. Sign in sheet for the opening conference is included as **Appendix 2**.

FACILITY DESCRIPTION

Motiva's Port Arthur refinery began a major expansion in 2008 to 2012 with the addition of a new crude oil distillation capacity, delayed coking, hydrotreating, catalytic cracking, sulfur recovery and other downstream processing. The permitted processing rate for the facility is now 635,000 barrels crude oil input per day. The refinery produces motor gasoline, diesel fuel, jet fuel, liquefied petroleum gas, and fuel oil. Crude oil is obtained primarily by ship and pipeline, while products leave the facility by pipeline, railcar, tank truck, and marine shipping. A plant wide process flow diagram and detailed facility description is included in **APPENDIX 3**.

Section II - OBSERVATIONS

Part IV, NO_x Emissions Reductions from Fluidized Catalytic Cracking Units (FCCU's) and Fluid Coker Units (FCU's)

Status: Complete.

Program Summary: Motiva shall incorporate lower NOx emission limits into operating permits and will demonstrate future compliance with the lower emission limits through the use of continuous emission monitoring systems (CEMS).

Motiva shall begin using NOx reducing catalyst at the Port Arthur FCCU and report the results of the optimization study. The FCCU will be operated at less than 20 ppm NOx on a 365 rolling day average and 40 ppm NOx on a rolling three hour average

APPENDIX 5 contains the FCCU NOx 365 day and 24 hour rolling average emission trends from March 2015 - March 2016. No exceedances of the limits occurred during the time period.

We observed the FCCU CEMS and that the calibration gases were of the correct concentration and up to date. I reviewed the relative accuracy test audit (RATA) results for the CEMs and found the relative accuracies to be within allowable requirements of 40 CFR, Part 60, Appendix F.

Part V, Reductions of SO2 Emissions FCCU's and FCU's

Status: Complete.

Program Summary: Motiva shall continue to operate the existing wet gas scrubber and incorporate lower SO_2 emissions into operating permits and demonstrate future compliance with the lower limits through use of CEM's. Motiva shall operate the Port Arthur FCCU so that SO_2 emissions do not exceed 25 ppm on a 365 day rolling average and 50 ppm based on a 7 day rolling average and shall monitor SO_2 emissions using CEMS.

Part V also requires compliance with NSPS Subparts A and J for SO_2, CO, particulate matter (PM) and opacity limits.

Appendix 6 contains FCCU SO_2 365 day and 7 day rolling average trends from March 2015 – March 2016. No exceedances were recording during the time period. During the inspection we observed the CEMS to be properly installed and that the calibration gases were up to date and of the proper concentrations. I reviewed the RATA results for the CEMS and found the relative accuracies for the CEMS to be within allowable requirements of 40 CFR, Part 60, Appendix F.

Appendix 7 is the FCCU CO one-hour rolling average trend from March, 2015 to March, 2016. Spikes in CO emissions during March, 2015 and October, 2015 are a result of the malfunctions previously reported to the State of Texas Excess Emissions Reporting System. The FCCU is equipped with an oxygen enrichment system if needed.

Part VI, Program Enhancements Regarding Benzene Waste NESHAP.

Status: On schedule.

Program Summary: Motiva shall undertake refinery-wide audits to determine its compliance with all Benzene Waste NESHAPS requirements and to take corrective action where any areas of non-compliance are identified. In addition Motiva shall undertake refinery wide measures to minimize or eliminate fugitive benzene waste emissions at the refinery.

Motiva is implementing the 2BQ compliance option of Subpart FF using upstream controls.

A schematic of the process is included as **APPENDIX 8**. Compliance sampling conducted at the outlet of treatment plant from January, 2015 to December, 2015 is included as **APPENDIX 8**. The trend indicates the 10 ppm limit imposed by NESAHP Subpart FF has not been exceeded.

I reviewed the sampling procedure and standard operating procedures (SOPs) being used and found the procedures written in a formal SOP and consistent with BWON sampling techniques required by 40 CFR § 61.355.

Part VII, Program Enhancements RE: Leak Detection and Repair (LDAR) Program Enhancements

Status: On schedule.

Program Summary: Motiva shall undertake audits of the components in light liquid and gaseous service at each of its refineries to determine compliance with all of the requirements of the Leak Detection and Repair ("LDAR") regulations and to correct any areas of non-compliance. In addition, Motiva shall undertake the CD listed enhancements to its LDAR program consisting of refinery-wide measures to minimize or eliminate fugitive emissions from components in light liquid and gaseous service at its refineries in accordance with the schedule set forth.

Third party audits, periodic reports and other requirements of Part XI of the consent decree have been previously reported to EPA and TCEQ.

Motiva uses in-house employees to conduct repairs and follow-up monitoring at the Port Arthur refinery. I reviewed instrument calibration logs and found that equipment calibration records are not being consistently signed by operators. Motiva has implemented a mid-day and the end of day drift check, as required by the CD. I reviewed the quarterly precision test results for the instruments being used at the facility, calibration gas certificates, and the most recent third party audit findings. Calibration gases observed were up to date and approximately equal to the leak definitions required by EPA Method 21.

I observed that electronic data collection for LDAR monitoring is being conducted by using data loggers and leak tracking and reporting software.

Records indicate annual training is being conducted and is incorporated into new employee orientation.

I walked through FCCU3, HTU 3 and 4, SRU 3, 4 and 5 and the waste water treatment plant and observed one open ended valve. Missing and illegible tags were evident in FCCU 3.

Part VIII, Program Enhancements RE: NSPS Subparts A and J SO2 Emissions from Sulfur Recovery Plants (SRP's) and Flaring

Status: On schedule.

Program Summary: Beginning immediately upon the lodging of this Consent Decree, Motiva agrees to take the following measures at all of its SRPs and certain flaring devices at the refineries identified in Paragraph 5. Motiva shall eliminate all reasonably preventable SO_2 emissions from flaring. Motiva will implement procedures for root cause analysis of acid gas flaring incidents at all refineries. Motiva shall strive to extend the duration between SRP maintenance shutdowns (unscheduled or scheduled) to three years or greater.

All flares at the facility are connected to one of two flare gas recovery systems installed as a result of the consent decree.

A graph of compressor operation (**APPENDIX 12)** shows the systems have sufficient compression and flow capacity.

I observed no smoke or flames being emitted by the flares. I also observed each flare using a FLIR© optical imaging device and observed no abnormal operation such as puffing or presence of non-combusted hydrocarbons.

The facility operates one SRU covered by the consent decree (SRU 1). The 12 hour average SO_2 emissions trend as recorded by CEMS is included as **APPENDIX 11**. The trend show the 250 ppm limit was exceeded at SRU1 in November, 2015 due to a unit trip.

I observed that the SO_2 analyzer was installed correctly and the calibration gas was of the correct concentration and up to date. I reviewed the RATA results for SRU CEMs and found the relative accuracies for the CEMS to be within the allowable requirements of 40 CFR, Part 60, Appendix F.

IX Permitting

Status: Complete.

Motiva agrees to apply for and make all reasonable efforts to obtain in a timely manner all appropriate federally enforceable permits (or construction permit waivers) for the construction of 'the pollution control technology required to meet the above pollution reductions.

Appendix 14 contains excerpts from the most recently revised NSR operating permits. Specific CD imposed limits are incorporated into the NSR permits and the Title V permit by reference.

Section III – AREAS OF CONCERN

An alternative monitoring plan for monitoring wet gas scrubber parameters for FCCU 1 has been provisionally approved due to a performance test conducted in 2014. However, the AMP has not been formally approved at this time.

Section IV – FOLLOW UP

N/A

Section V – LIST OF APPENDICES

Appendix 1 - Photo Log (11 photos taken 3/29-30/2016)
Appendix 2 - Opening conference sign-in sheet
Appendix 3 - Plant wide process flow diagram and written description
Appendix 4 – CEMS required by consent decree
Appendix 5 – FCCU NO_x emission trends
Appendix 6 - FCCU SO_2 emission trend
Appendix 7 – FCCU CO emission trend
Appendix 8 - BWON schematic
Appendix 9 – BWON analytical data for feed
Appendix 10 – SRU block flow diagram
Appendix 11 – SRU SO_2 emission trends
Appendix 12 – Compressor inlet/outlet flows and spill back
Appendix 13- Acid gas and hydrocarbon flaring events
Appendix 14 - Operating permit excerpts

Appendix CBI (None)

Appendix 1

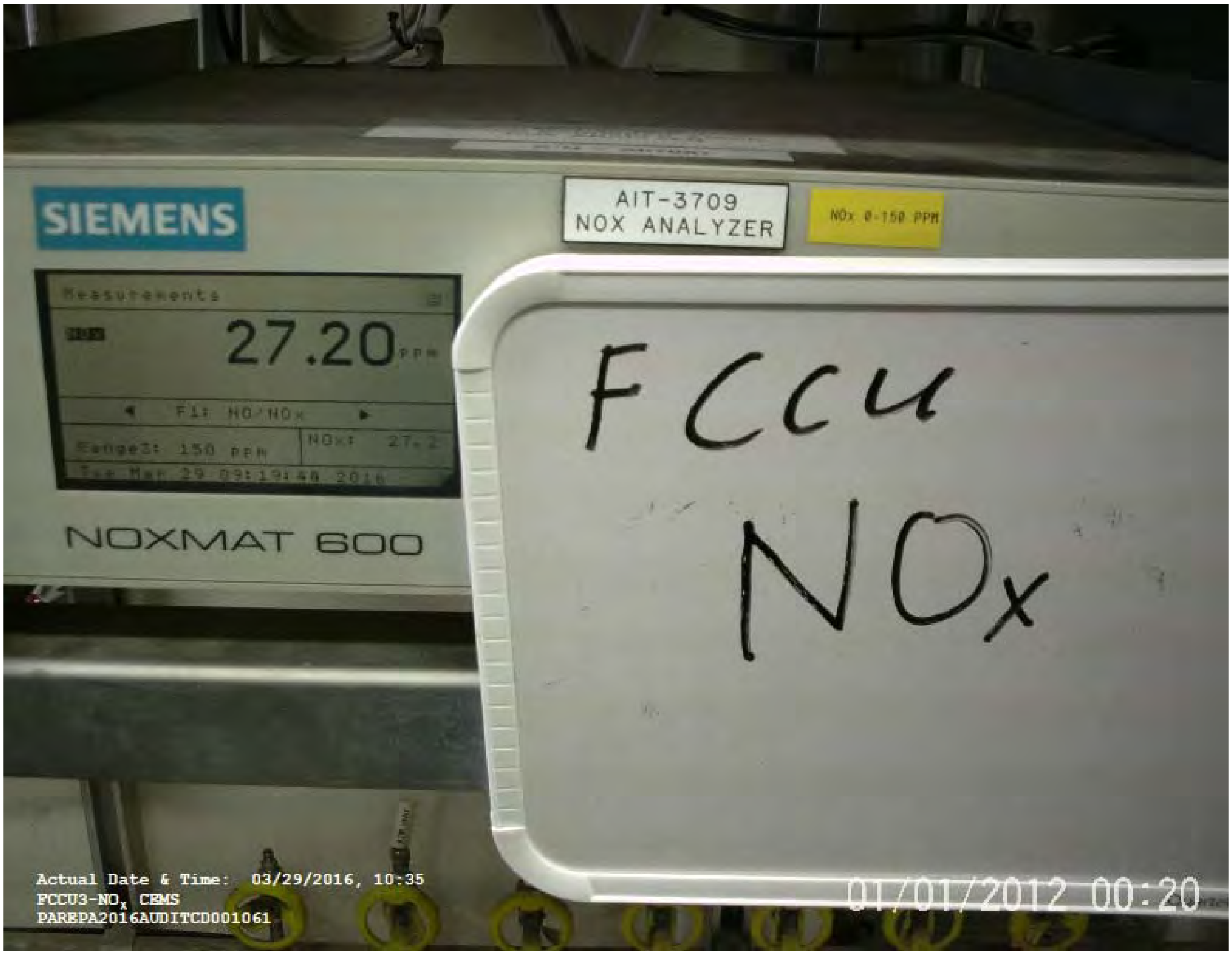
Photograph Log

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 1

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas



FCCU NO_x CEM

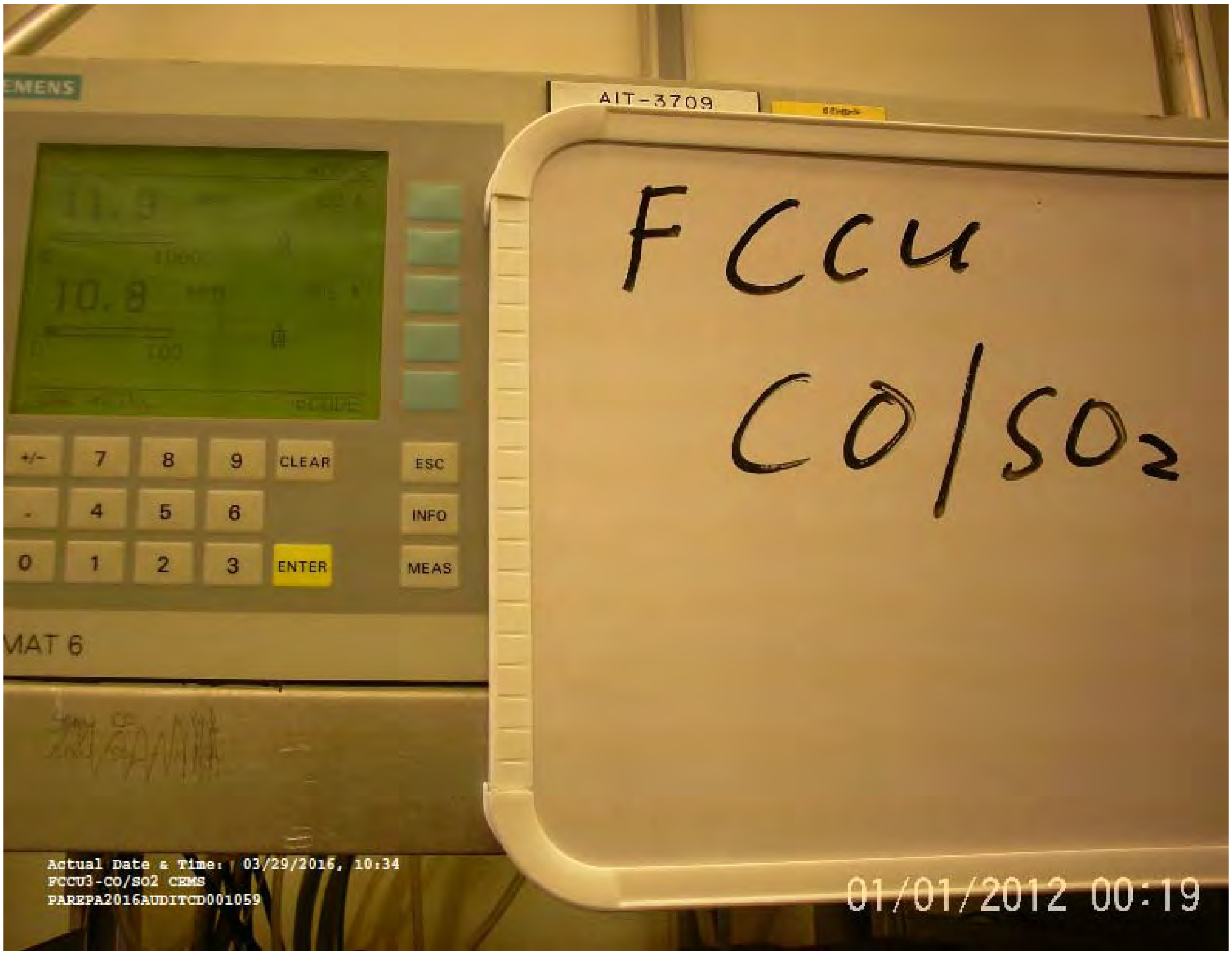
NO_x = 27.20 ppm

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 2

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas



FCCU CO/SO_2 CEMs.

CO = 11.9 ppm

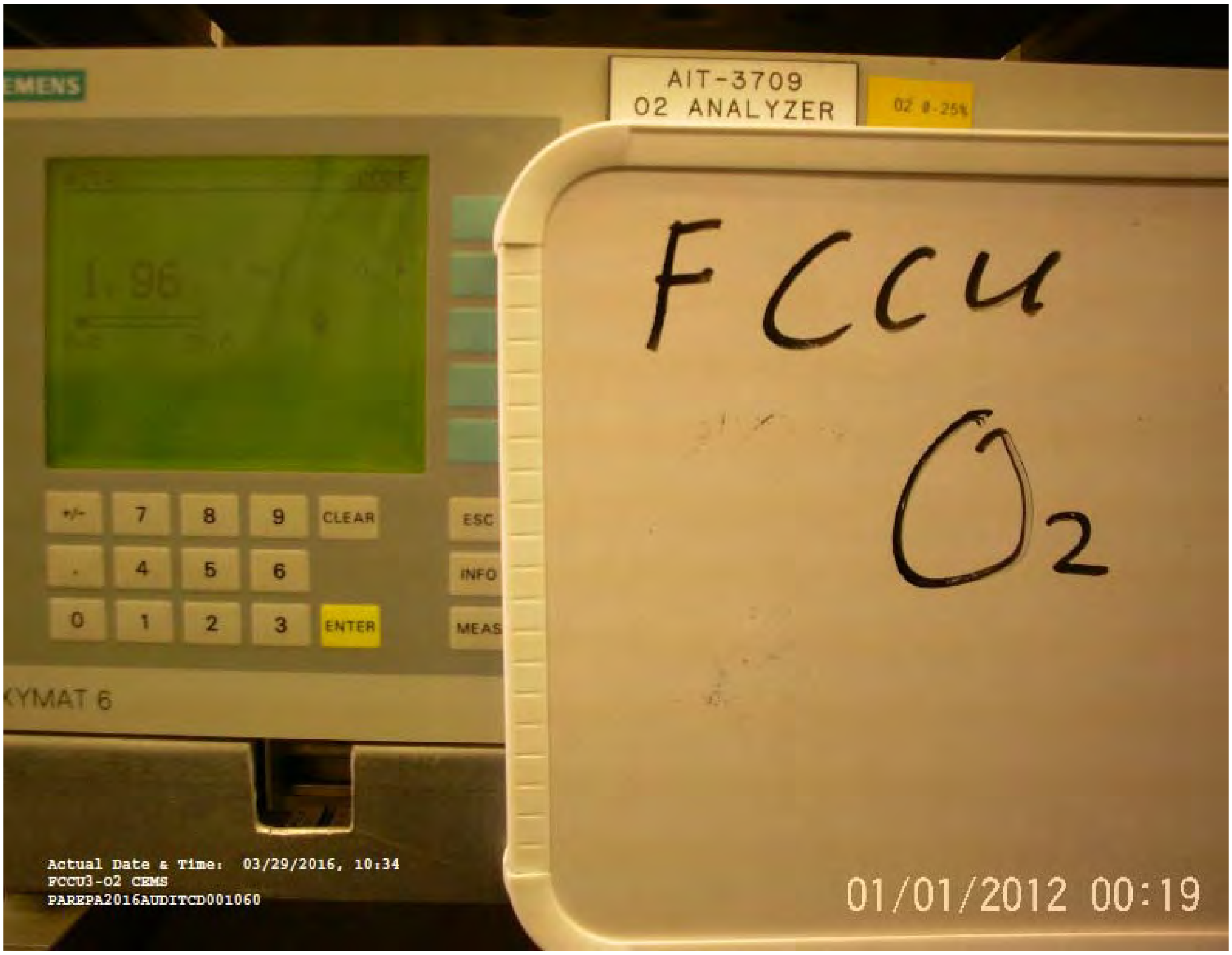
SO_2 = 10.8 ppm

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 3

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas



FCCU O_2 CEM

O_2 = 1.96 %

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 4

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas

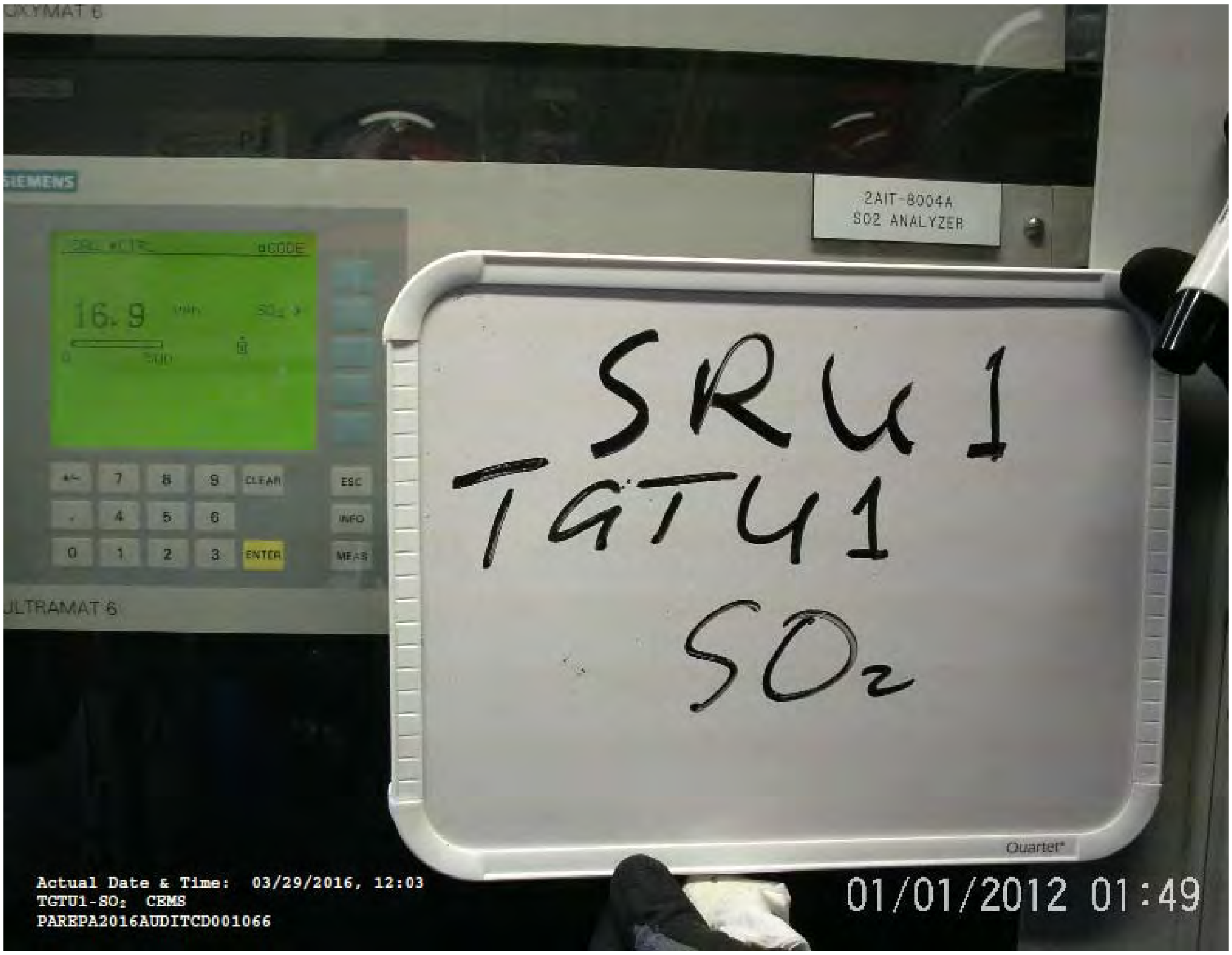
FCCU #3 Belco Wet Gas Scrubber

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 5

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas



Sulfur Recover Unit #1 Tail Gas Unit SO_2 CEM

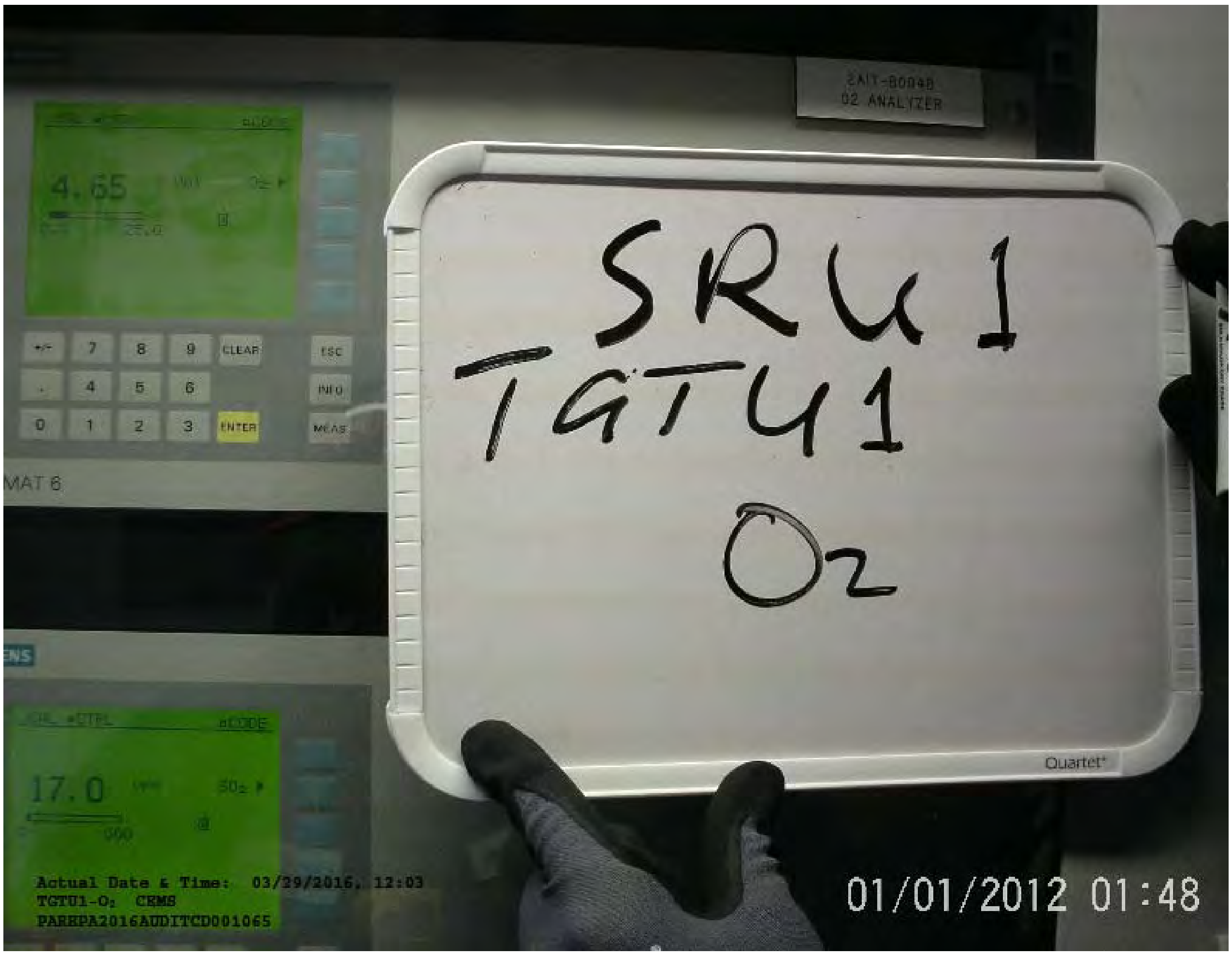
SO_2 = 16.9 ppm

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 6

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas



Sulfur Recovery Unit Tail Gas O_2 CEM

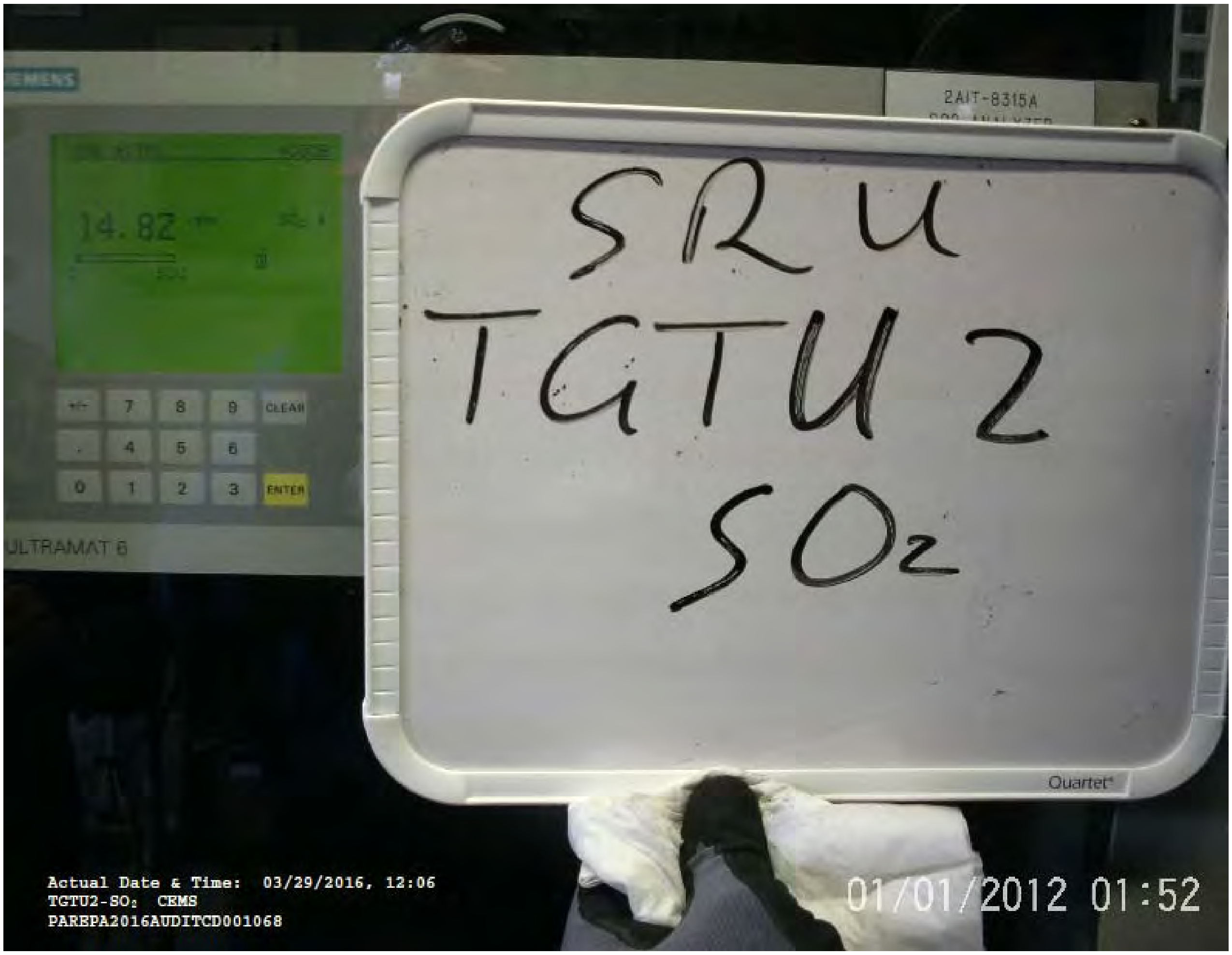
O_2 = 4.65 %

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 7

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas



Sulfur Recovery Unit Tail Gas Unit #2 SO_2 CEM

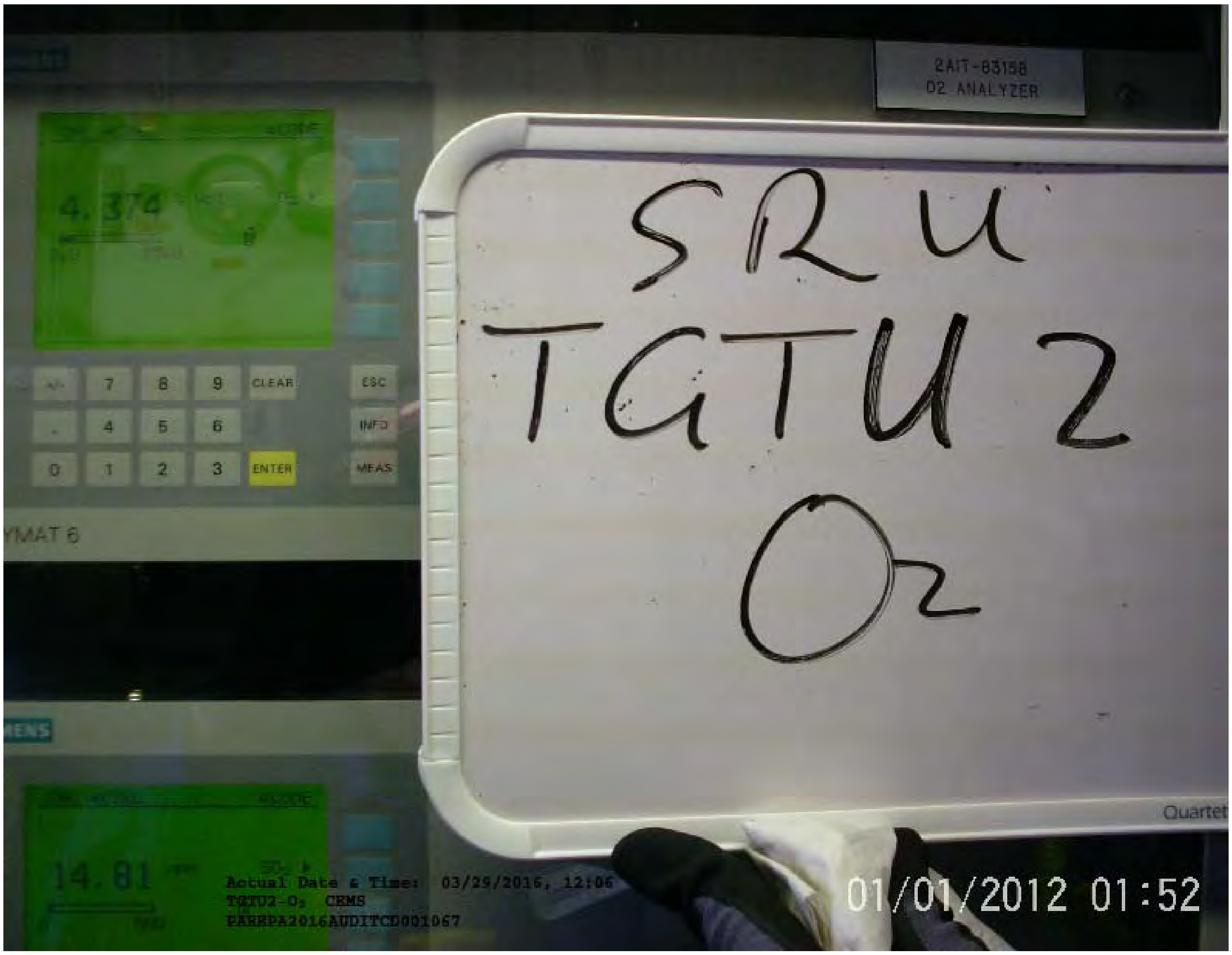
SO_2 = 14.82 ppm

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 8

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas



Sulfur Recovery Unit Tail Gas Unit #2 O_2 CEM

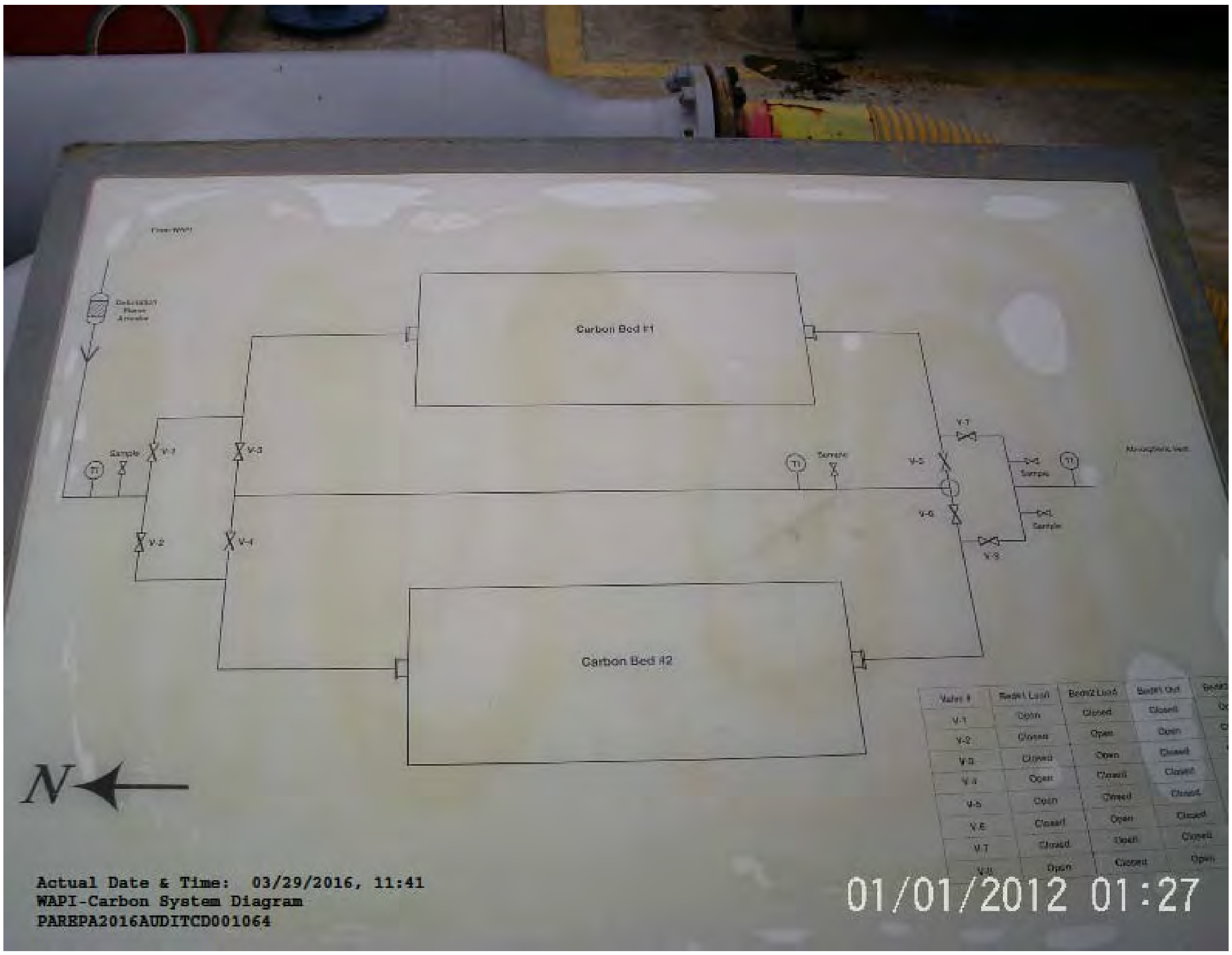
O_2 = 4.374 %

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 9

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas



Waste Water Treatment BWON Carbon Bed Control Display

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 10

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas

Waste Water Treatment Plant BWON Carbon Beds with shut down Thermal Oxidizer.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Photograph Log

Photo No. 11

Location: Motiva Enterprises LLC		
City: Port Arthur	County/Parish: Jefferson	State: Texas

Flare Gas Recovery Compressors.

Appendix 2

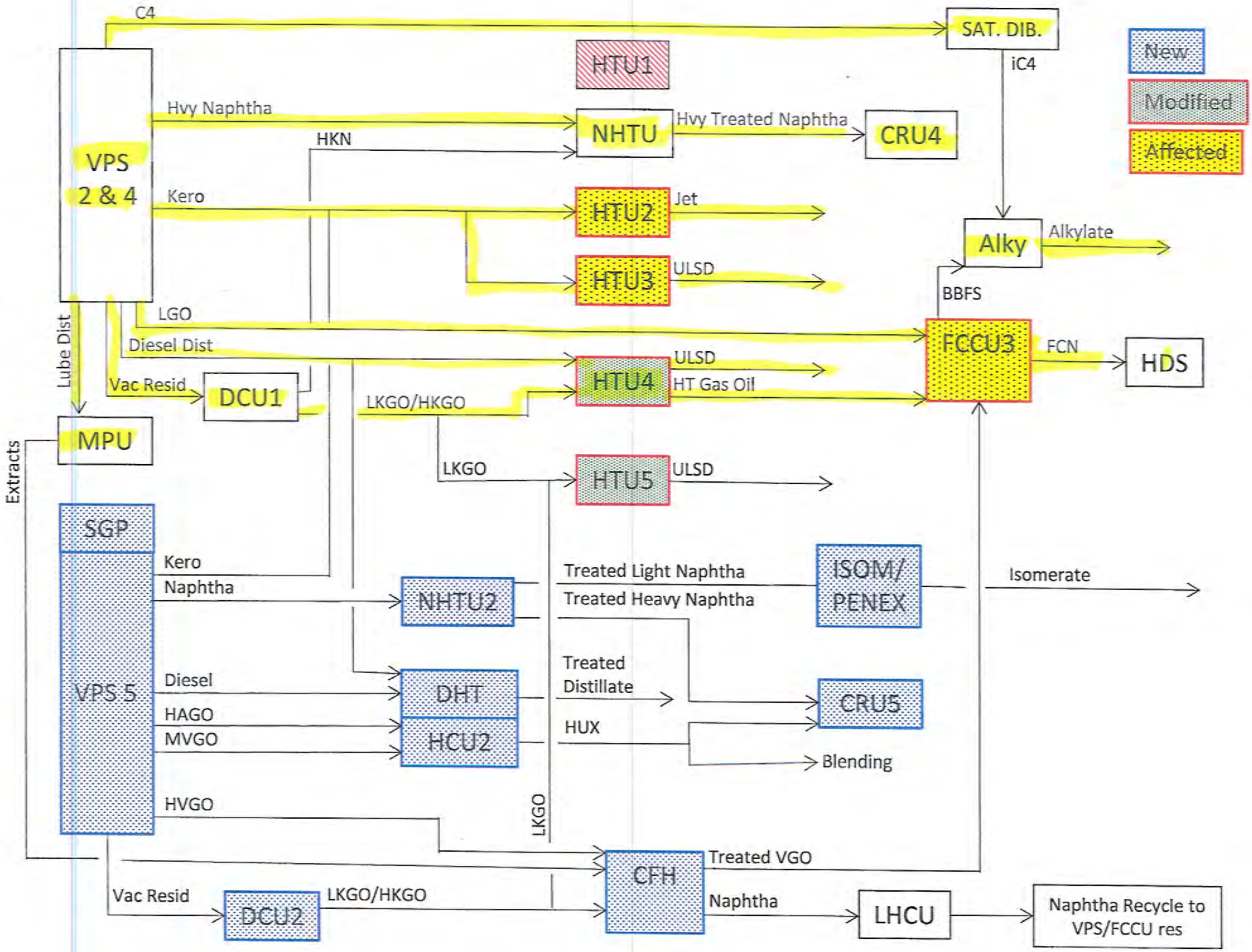
Opening conference sign-in sheet

Personnel in Attendance
MOTIVA ENTERPRISES LLC, PORT ARTHUR, TEXAS
CD Inspection
Date: 3/28/2016

Name *(Please Print)*	Affiliation	Title	Contact Information *(Phone/ Email)*
Jim Gold	US EPA	insp.	281 983 2153
Damian Fryonk	Motiva	Tch. Env. Mgr.	504-275-8782
Brenda Allen	Motiva	Claims Mgr.	409-206-5030
Susan Flowers	Motiva	HSSE Manager	409-989-7591
Janet Fox	Motiva	Env. Mgr.	409548-3741
PRINCE NFODZO	US EPA	ENV. ENGINEER	214 665 7491
Ryan Yoes	Motiva	Env. Specialist	409 971 6248
Brian Faulkner (only on 3/30/16)	Shell Oil Co.	Legal Counsel - Envtl	713-241-2383

▢ - CD Applicable

Figure 1. New/Modified CEP Process Units at Port Arthur Refinery



Appendix 3

Plant wide process flow diagram and written description

JD Consulting, L.P.
404 Camp Craft Road
Austin, Texas 78746
512-347-7588
fax - 512-347-8243

Application for
Air Permit Amendment and Renewal
Flexible Permit No. 8404

Refinery Expansion Project
Motiva Enterprises LLC
Port Arthur, Jefferson County, Texas

January 2006
(With Supplements)

4 Existing Refinery Process Description

A process description of existing operations at the Port Arthur Refinery (PAR) is presented in this section. The description addresses all the refinery processing units, the Sulfur Recovery Units, the Tank Farms, Loading Operations, and Utilities. The descriptions of sources of feedstocks and destination of products from individual units are representative but not inclusive of all operations at the existing refinery. A list of the emission sources associated with existing PAR operations authorized by Permit No. 8404 is included as Table 4-1. A process flow diagram of the existing operations is shown in Figure 4-1.

The existing Port Arthur Refinery processes crude oil into several finished products, which include aviation jet fuel, several grades of motor gasoline, diesel fuels, and lubricating oil base stocks. The refinery consists of several processing units. These can generally be divided into separation, conversion, and treatment operations, with various support operations. The separation process occurs in the Vacuum Pipe Stills (VPS2 & VPS4). Conversion occurs in the Fluid Catalytic Cracking Unit (FCCU3), the Catalytic Reforming Unit (CRU4), the Lube Catalytic Dewaxing Unit (LCDU), the Lube Hydrotreating Train (HTU4LT), the Alkylation Unit (ALKY), the Hydrocracking Lube Conversion Unit (HCU), and the Delayed Coking Unit (DCU1). Treating occurs in the Hydrotreating Units (HTU1, 2, 3, 4), and the Methyl Pyrrolidone Units (MPU3 & 4). The support operations include the Sulfur Block Unit, storage of intermediate and final products, loading operations, and the Power Plant and associated utilities.

Crude oil, the refinery's feedstock, is separated by distillation into fractions of different boiling points. Some of these fractions are more desirable than others, depending on customer demand. The less desirable fractions are converted by catalytic cracking, catalytic reforming, alkylation, and hydrocracking into more desirable or profitable fractions. Some fractions may require treating to remove sulfur or other impurities, improve color or stability, or remove heavy residues. Finally, various fractions are blended to create the motor fuels, solvents, and lubricants that comprise many of the refinery's end products.

4.1 Vacuum Pipe Stills

The purpose of the Vacuum Pipe Stills (VPS2 & VPS4) is to separate crude oil into various fractions through distillation. Raw crude oil is charged to the desalters where the crude is water-washed to reduce salt and sediment. The oil and water are separated electrostatically. After the crude oil has been desalted, it is heated and charged to an atmospheric tower, where several fractions are distilled. The atmospheric tower bottoms are heated and charged to the vacuum tower. The vacuum tower operates at below

PAR EPA2016AUDITCD
000049

atmospheric pressure, allowing heavy gas oils to be recovered while minimizing cracking of the oil. The vacuum tower bottoms are called "vacuum residuum" or simply "residuum". Other side streams from VPS2 & VPS4 include off gas; a C_3 stream, which is sent to the refinery fuel gas system and used as fuel in the existing PAR furnaces and process heaters; a mixed C_4 stream; light naphtha; heavy naphtha; kerosene; diesel distillate; light gas oil; and a mixed stream of heavy gas oil and lube distillate. In addition to the exception noted above, a portion of light naphtha is currently sold without additional treating. All other side streams are further processed at the PAR before being sent to sales.

4.2 Catalytic Reforming

The Catalytic Reforming Unit (CRU4) is one of several conversion units at PAR, with its purpose being to increase the octane rating of low octane gasoline in order to improve the motor fuel's anti-knock properties. CRU4 consists of two naphtha hydrotreating units (NHTUs) for removing sulfur and nitrogen from the feed, a platformer, a gas recovery section, and a regenerator section for renewing spent catalyst. CRU4 is first charged with heavy naphtha from VPS2 & VPS4, heavy naphtha from the Delayed Coking Unit (DCU1); mixed naphtha from the LCDU, HTU4LT, and HCU Lube Conversion Unit; and naphtha from existing Hydrotreating Units No. 1 through 4 (HTU1, 2, 3, 4) and another Hydrotreating Unit (HTU5) that will be brought on-line prior to start-up of the refinery expansion. The charge is sent to the NHTUs where sulfur, nitrogen, and other contaminants are removed. The stream then enters a process reactor that uses a platinum catalyst to rearrange the molecular structure. This produces a higher percentage of aromatics and isoparaffins, which increases the octane value of the feedstock to 95 or higher. The CRU4 products are higher octane motor gasoline, hydrogen, an ethylene/propylene (E/P) mix, and mixed butanes, which is sent to the saturated de-isobutanizer for further processing. The E/P mix is sold via pipeline.

The continuous catalyst regeneration (CCR) system consists of a catalyst withdrawal system at the bottom of the platforming reactor, a lock hopper to separate the hydrogen atmosphere from the oxygen atmosphere of the regenerator, a catalyst lift system, a regenerator vessel, flow control hopper, catalyst surge hopper, a second lock hopper and catalyst lift system, and a reduction zone on top of the platforming reactor. The CCR uses a controlled combustion process to burn coke off of the catalyst, which restores its activity. A system of lock hoppers is used to separate the hydrogen and oxygen-rich environments to ensure safe operation.

4.3 Hydrotreating Units

Hydrotreating or catalytic hydrodesulfurization is an important refinery process for improving the quality of middle distillates. The purpose of the Hydrotreating Units (HTU1-5) is to remove sulfur and nitrogen

PAR EPA2016AUDITCD
000050

from the feedstocks; reduce acidity; stabilize hydrocarbon compounds from olefins and other unsaturated hydrocarbons; absorb metallic impurities such as copper, nickel, lead, vanadium, and arsenic onto the catalyst; and improve color and thermal stability.

Hydrotreating takes place at moderate temperatures and at moderate to high pressures in the presence of hydrogen and a catalyst. The charge, which consists of gas oils, kerosene, diesel, and naphthas, mainly from VPS2 & VPS4, is heated and combined with hydrogen. The mixture is routed through fixed beds of catalyst to produce hydrotreated products ranging from naphtha and kerosene to diesel and desulfurized FCCU charge. Sulfur and nitrogen are converted to hydrogen sulfide and ammonia, which are removed from the reactor product gas stream by absorption with methyl diethanolamine (MDEA). The sweetening of the feedstock (by removing the sulfur) in the HTUs improves the product's clarity and color. Finished products are desulfurized FCCU charge, jet fuel, low sulfur diesel, and low sulfur gasoline blendstocks.

4.4 Delayed Coking Unit

The function of the Delayed Coking Unit (DCU1) is to upgrade the vacuum residuum from VPS2 & VPS4 into higher value products. The residuum feed from storage is preheated by exchange with hot products and then fed into the bottom of the fractionator. The fractionator bottoms are pumped through the coker furnaces and then into the coke drums where solid petroleum coke forms. The hydrocarbon gas passes through the coke drums and is then routed back to the middle of the fractionator. Heavy cycle gas oil (HCGO) from FCCU3 may be mixed with the residuum feed and charged directly to the coke furnaces. Three gas oils are drawn from the main fractionator. Light gas oil is stripped, cooled, and sent off-site via pipeline for further processing. Heavy gas oil is also stripped, cooled, used for heat exchange, and sent off-site via pipeline for further processing. Flash zone oil is used for process heat recovery and then mixed with the heavy gas oil as it goes off-site via pipeline or can be recycled to the furnaces. Products from the DCU are fuel gas, a mixed propane/propylene stream, a mixed butane/butylene stream, light naphtha, heavy naphtha, light coker gas oil (LKGO), heavy coker gas oil (HKGO), and fuel grade petroleum coke. With the exception of the fuel gas, which is fired in the refinery furnaces and process heaters as fuel, and the petroleum coke, which is sent to sales, all other DCU1 products are sent to other refinery units for further processing. The mixed propane/propylene stream is routed to the recovery section of FCCU3 or can be burned as fuel gas, the mixed butane/butylenes stream (or butane/butylenes feedstock, BBFS) is sent to the Alkylation Unit, the light naphtha is sent to HTU1, the heavy naphtha is sent to CRU4, and the LKGO and HKGO are sent to HTU4&5.

The petroleum coke needs to be "cut" prior to being sent to sales. When one set of coke drums fills, alternate drums are placed into service, and the first drum is prepared for decoking. The decoking process

PAR EPA2016AUDITCD
000051

involves steam purging and quenching of the hot coke with water until it is cool enough to be cut from the drum using a high pressure hydraulic cutting bit. The coke falls from the bottom of the drum into a pit.

Coke from the wet storage pit is be moved by a crane to a storage pile. The storage pile is moistened by water sprays as required to reduce dust emissions due to wind erosion and maintenance. The coke is loaded out of the pile and into a crusher via an overhead crane. It is then crushed and loaded by a belt feeder onto a conveyor, and then loaded into a silo. Loading of the coke into railcars is accomplished by gravity feed from the silo. Although railcars are used almost exclusively to haul the coke, trucks are occasionally used. If trucks are used, the coke is watered down and the trucks washed prior to leaving the DCU1.

4.5 Fluid Catalytic Cracking Unit

The Fluid Catalytic Cracking Unit (FCCU3) charge stock consists primarily of heavy gas oils, mainly from VPS2 & VPS4, HTU4, and DCU1, with boiling points from 650°F to 1000°F. The charge gas oil is contacted with catalyst at low pressure and high temperatures within parallel vertical riser tubes to the reactor. In the reactor, heavy oils are cracked to produce coke, cycle gas oils, gasoline, butylenes, propylene, and other gases. The majority of the cracking reactions take place in the riser tubes. As the mixture enters the reactor, steam strips the hydrocarbons from the catalyst. The catalyst used in the process is a fine silica-alumina powder. Catalyst fines are separated by internal cyclones and the majority of the hydrocarbon vapors are condensed within the fractionator. The noncondensible gases enter a gas recovery system. Spent catalyst leaves the reactor and enters a regenerator where excess air is added to the hot catalyst to burn off coke deposits. The regenerator flue gas is currently routed to a CO boiler to utilize the stream's available heating value to generate steam. The CO Boiler will be converted to a non-fired waste heat boiler during the first quarter of 2006. The regenerator will then operate in "full combustion" mode to enable the regenerator to minimize CO emissions without the necessity of a CO boiler. Emissions from FCCU3 enter a wet gas scrubber where SO_2 and catalyst fines are recovered from the flue gas.

The regenerated catalyst, along with fresh make-up catalyst, enters the riser tube with the feed charge to begin the cycle again. FCCU3 also includes a CD-HDS Unit. This unit uses hydrogen in a catalytic distillation refluxed reactor to remove sulfur from the cracked naphtha from FCCU3. The desulfurized naphtha is used for gasoline blending to meet reformulated gasoline emission specifications.

Fresh catalyst is brought in by truck and transferred to the fresh catalyst hopper via a hose connection. The fresh catalyst is normally loaded continuously into the regenerator. Spent catalyst is routinely

PAR EPA2016AUDITCD
000052

removed from the regenerator into spent catalyst hoppers. The spent catalyst is transferred to trucks via a hose connection and then shipped out for reuse by other refiners.

4.6 Lube Catalytic Dewaxing Unit and Hydrotreating Lube Train

The Lube Catalytic Dewaxing Unit (LCDU) and Hydrotreating (HTU4) Lube Train produces lubricating (lube) base oils by catalytically removing the wax from the oil to improve the pour point (temperature where the oil becomes solid). Refined wax distillates and hydrogen are charged to a hydrotreating reactor to remove sulfur and nitrogen. The hydrotreater product is stripped, charged to a dewaxing reactor, and then to an aromatics saturation reactor. Light ends created in the dewaxing process are stripped out and recovered as fuel gas, naphtha is routed to VPS4 for further processing, and diesel is used as blendstock. The finished lube base oil is sold to produce high quality oil and industrial lubricants.

Hydrotreater catalyst is changed approximately every 18 months. The units are first degassed to the refinery fuel gas system until the pressure reaches approximately 65 psig, then they are degassed to the flare gas recovery system until the pressure reaches approximately 5 psig, and lastly, they are steamed to the flare. The vessels are placed under a nitrogen blanket while the spent catalyst is removed and the fresh catalyst is installed. The units are then returned to service. Spent catalyst is either recycled, disposed, or processed to reclaim metals.

4.7 Lube Hydrocracking Unit

The Lube Hydrocracking Unit (LHCU), also known as the Hydrocracking Lube Conversion Unit, operates in the same manner as the LCDU using wax distillates as feedstock.

4.8 Alkylation Unit

The alkylation process involves the reaction of low molecular weight olefins with an isoparaffin to form higher molecular weight isoparaffins. The resulting alkylate is a high octane gasoline that can be used as aviation gasoline or a blending component for motor gasoline. The process takes place at low temperatures and is conducted in the presence of sulfuric acid, which acts as a catalyst to promote the reaction between the light olefins and isobutane. High isoparaffin/olefin ratios are used to minimize polymerization, increase the alkylate product's octane rating, and ensure essentially complete conversion of the feedstock to the desired end product.

Feedstock to the unit consists of light olefins from FCCU3 and the DCU, and isobutane. The feedstock and the sulfuric acid are first agitated in the contactors and the resulting emulsion is sent to the settlers for phase separation. The acid is recirculated and the pressure of the hydrocarbon phase is lowered to flash vaporize a portion of the unreacted isobutane. This reduces the liquid temperature, which in turn provides

PAR EPA2016AUDITCD
000053

refrigeration for controlling the contactor temperature by removing reaction heat. The emulsion is further separated and the spent acid is recovered for regeneration. The chilled mixture is neutralized and sent to fractionators to recover LPG-grade propane, n-butane, and light and heavy alkylate. Isobutane is also recovered and recycled to the reaction section. The finished products are blended into aviation gasoline and motor gasoline, which are then stored on-site prior to being shipped off-site via pipeline.

The Alkylation Unit also includes a Selective Hydrotreating Unit (SHU). The SHU charges light olefin streams and hydrogen and uses a selective catalyst to saturate di-olefins to mono-olefins. By removing the di-olefins, acid use in the alkylation reaction is greatly reduced.

4.9 Methyl Pyrrolidone Units

The purpose of the Methyl Pyrrolidone Units (MPU3&4) is to remove undesirable components from the feedstock, which is typically raw lubricating (lube) oils. Methyl pyrrolidone is a solvent that preferentially removes aromatics and highly unsaturated compounds from the raw lube oils. The MPU3&4 process begins by contacting the solvent with the raw lube oils in a treating tower. Overhead from the treating tower consists of refined oil (a mixture of solvent and lube oil) and the bottoms consist of an extract mix (a mixture of solvent and aromatics). The refined oil and extract mix are then sent to separate vacuum and/or atmospheric flash and vacuum steam stripping trains to separate the solvent and recycle it for further use in the MPU3&4. The treated lube oil and the aromatic extract are then sent off-site to storage and are used as charge to the lube units.

4.10 Miscellaneous PAR Operations

Various miscellaneous PAR operations are included in Permit No. 8404. A brief description of each of these facilities follows.

4.10.1 Pumphouse 27 Tank Farm (PH27)

This tank farm is used for storage of unfinished blend stocks and finished refinery products prior to shipment offsite via pipeline.

4.10.2 Landfarm

This land farm is used for disposal of non-hazardous waste and has no routine emissions.

4.10.3 BS&W

This tank farm stores process oil and water mixes, such as tank water bottoms and bottoms from flare knockout drums. The oil is recovered for further processing and the water is sent to the sour water stripper.

PAR EPA2016AUDITCD
000054

4.10.4 Light Oil Treating Area (LOTA)

The LOTA is no longer operational and will be dismantled after March 1, 2006.

4.10.5 North Side Gas Plant (NSGP)

In this unit, recovered hydrocarbons are compressed by either an electric motor-driven compressor or a gas-fired compressor engine, sweetened to remove the H_2S, and then returned to the refinery fuel gas system. This unit includes a vapor recovery system for the north side of the refinery and scrubbers for the low and high pressure fuel gas.

4.10.6 Pumphouse 57 Tank Farm (PH57)

This tank farm is used for storage of crudes and intermediate products.

4.10.7 WAGS

This unit amine treats sour gas streams from several process units.

4.10.8 West Side Gas Plant (WSGP)

This unit serves essentially the same purpose as the NSGP, except it serves the west side of the refinery. It has three gas-fired compressor engines and provides fuel gas collection and distribution, natural gas make-up, vapor recovery, and fuel gas scrubbing.

4.11 Sulfur Block Unit

The Sulfur Block Unit (SBU1) includes the Amine Recovery Units, Sour Water System, and Sulfur Recovery Units as described below.

4.11.1 Amine Recovery Units

The purpose of the Amine Recovery Units (ARUs) is to strip H_2S from the rich methyl diethanolamine (MDEA) generated in upstream processing units. Lean MDEA is used to absorb H_2S from sour gas at the refinery process units and steam is used to strip H_2S from the rich MDEA in the ARUs. The resulting off-gas from the reflux accumulator, otherwise known as acid gas, is sent to the sulfur recovery units for further processing. Liquid (mostly steam condensate) from the reflux accumulator is sent to the Activated Sludge Treatment Unit or is introduced back into the top of the stripper as reflux. Regenerated amine leaves the bottom of the stripper tower and is returned to various refinery units to treat sour gas from those units.

4.11.2 Sour Water System

Sour water from the refinery process units is sent to surge tanks, which provide three days residence time, prior to being processed in a sour water stripper (SWS). The sour water is heated in the feed/bottom

PAR EPA2016AUDITCD
000055

exchangers and enters the SWS where steam is injected. The stripping system flashes off H_2S and ammonia (NH_3), which leave the tower and go through a knockout drum prior to being sent to the Sulfur Recovery Units. Stripped sour water leaves the bottom of the drum and is sent to the Activated Sludge Treatment Unit.

4.11.3 Sulfur Recovery Units

The three Sulfur Recovery Units (SRU2, 3, &4) operate in parallel using Claus technology to process the acid gas streams from the ARUs and the SWS offgas. The ARU acid gas streams and the SWS offgas first enter a thermal reactor, which is equipped with oxygen enrichment using proprietary injection systems. About one-third of the H_2S feed is oxidized to SO_2, which then reacts with the remaining H_2S to form elemental sulfur and water. The primary reaction takes place in the thermal reactor where the majority of the sulfur is formed. The hot gas is cooled in a boiler, which makes high pressure steam, and is further cooled in the first pass of the primary condenser, which makes low pressure steam. The stream makes three passes in the primary condenser and after each pass, the gas is reheated and passed through a catalyst bed where the SO_2 and H_2S gases again react to form elemental sulfur. In each pass of the primary condenser, the gas is cooled and condensed, and the liquid sulfur drains into a sulfur pit. The sulfur pit is normally vented to the SRU thermal section for control of emissions. Carbon canisters are used as backup during SRU outages. The gas from the third catalyst bed goes to the final sulfur condenser where the sulfur is condensed and drained into the sulfur pit. Approximately 97% of the sulfur is recovered in the SRUs. The H_2S/SO_2 gas that was not converted to elemental sulfur is sent to a tail gas treating unit.

4.11.4 Tail Gas Treating Units

The two Tail Gas Treating Units (TGTUs) are designed to convert H_2S and SO_2 from the SRU tail gas to elemental sulfur. Both TGTUs are dedicated units with TGTU1 treating the tail gas from SRU2&3 and TGTU2 treating the tail gas from SRU4. The SRU tail gas is processed in a hydrotreating reactor, where SO_2 is reduced to H_2S and returned to the SRU. The tail gas from the TGTU is incinerated and emitted to the atmosphere.

Tail gas from the SRUs is heated in the feed heater and then combined with hydrogen gas before entering the hydrotreating reactor. In the reactor, SO_2, sulfur, carbonyl sulfide, and carbon disulfide are converted to H_2S. This gas is cooled in a waste heat boiler, where 40 psig steam is made, and goes to a quench tower. It is further cooled and washed before going to the absorber tower. A lean amine solution in the absorber tower absorbs about 99% of the H_2S from the feed stream, becoming rich amine. The gas that is not absorbed, which contains residual H_2S, leaves the top of the absorber tower and is burned in the Tail

PAR EPA2016AUDITCD
000056

Gas Incinerators. The rich amine goes to the stripper tower and the lean amine is then cooled an to the absorber tower. The H_2S and CO_2 gas stripped from the rich amine is cooled and goes to t drum where the water settles and is returned to the stripper towers. The recycled gas containing and CO_2 is then routed to the MDEA acid gas knockout drum to be used in the SRU acid gas fee

4.12 Tank Farm

There are numerous tanks located throughout the PAR that are used for storage of intermediate a products. These storage tanks consist of fixed roof tanks that either vent to atmosphere or to the vacuum system, internal floating roof tanks, or external floating roof tanks.

4.13 Loading Operations

Finished products are shipped out of the refinery either by pipeline, railcars, or tank trucks.

4.14 Utilities

Existing utilities consist of the power plant, flares, cooling towers, and the wastewater collection treatment system.

4.14.1 Power Plant

Steam and electricity are generated from five gas-fired power boilers and two waste heat boilers equipped with duct burners. These boilers are authorized under TCEQ approvals other than Perr 8404. They are mentioned here for completeness only.

4.14.2 Flares

Eight existing flares are used for emergency purposes and during start-up, shutdown, and mainte activities. These flares are located throughout the PAR. Most of these flares serve more than on unit and are associated with VPS2/VPS4, CRU4, HTU, DCU1, FCCU3, LCDU, HCU, LHCU, A ARU1/ARU2 and SBU1/SBU2.

A flare gas recovery (FGR) system is used upstream of the flares to recover noncondensibles fro vent gas streams. These noncondensibles are then blended into the refinery fuel gas system and fuel throughout the refinery.

4.14.3 Cooling Towers

Eleven cooling towers supply cooling water throughout the PAR.

4.14.4 Wastewater Collection and Treatment System

Wastewater is transported to the treatment system via an enclosed collection system. Fugitive en from process unit drains and an associated lift station are included in Permit No. 8404. The treat system itself consists of an API separator, two equalization tanks, two supplemental activated sludge units, two aerated biotreatment areas, three clarifiers, and miscellaneous storage tanks, covered separators, and closed sumps. The existing wastewater treatment system is authorized under TCEQ approvals other than Permit No. 8404 and is mentioned for completeness only.

4.14.5 Maintenance Operations

Maintenance operations include tank cleaning and/or repair, pressure vessel degassing for cleaning and/or repair, and painting of on-site structures and vessels for corrosion prevention, which are performed on an as-needed basis.

Tank cleaning/repair involves three steps: first, the tank is pumped dry; which causes the roof to "land"; second, the vapor space is vented to a control device, generally a flare; and lastly, the tank is opened for cleaning or repair.

Process vessels are depressurized either to the flare gas recovery system (FGR) or a control device until the vessel pressure is reduced to 5 psig. Whenever possible and practicable, the remaining contents of the vessel are purged with an inert gas to the FGR. Otherwise, the remaining contents of the vessel are vented to atmosphere, at which point the vessel can be opened or entered for cleaning and/or repair.

PAR EPA2016AUDITCD
000058

Appendix 4

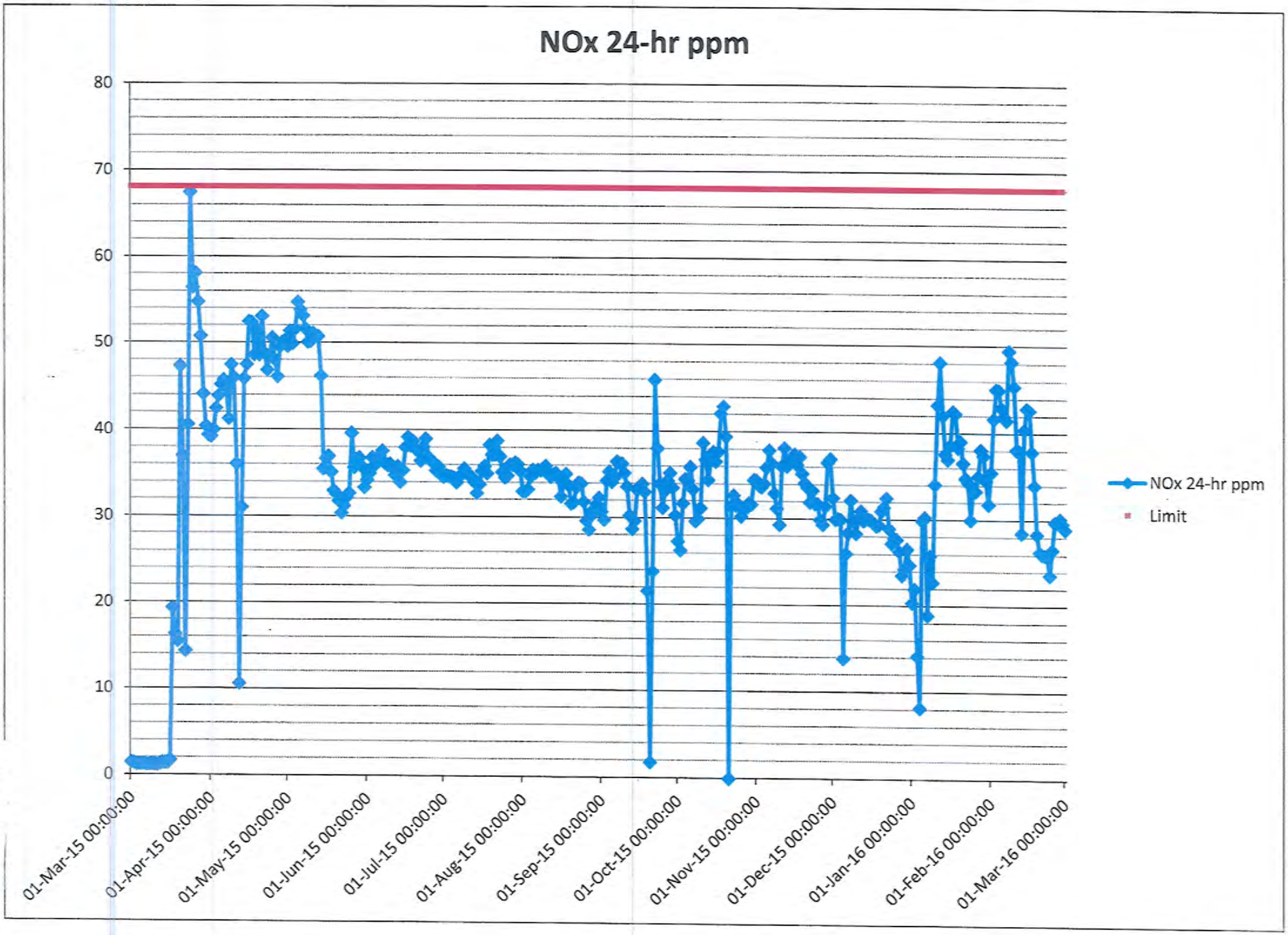
CEMs required by consent decree

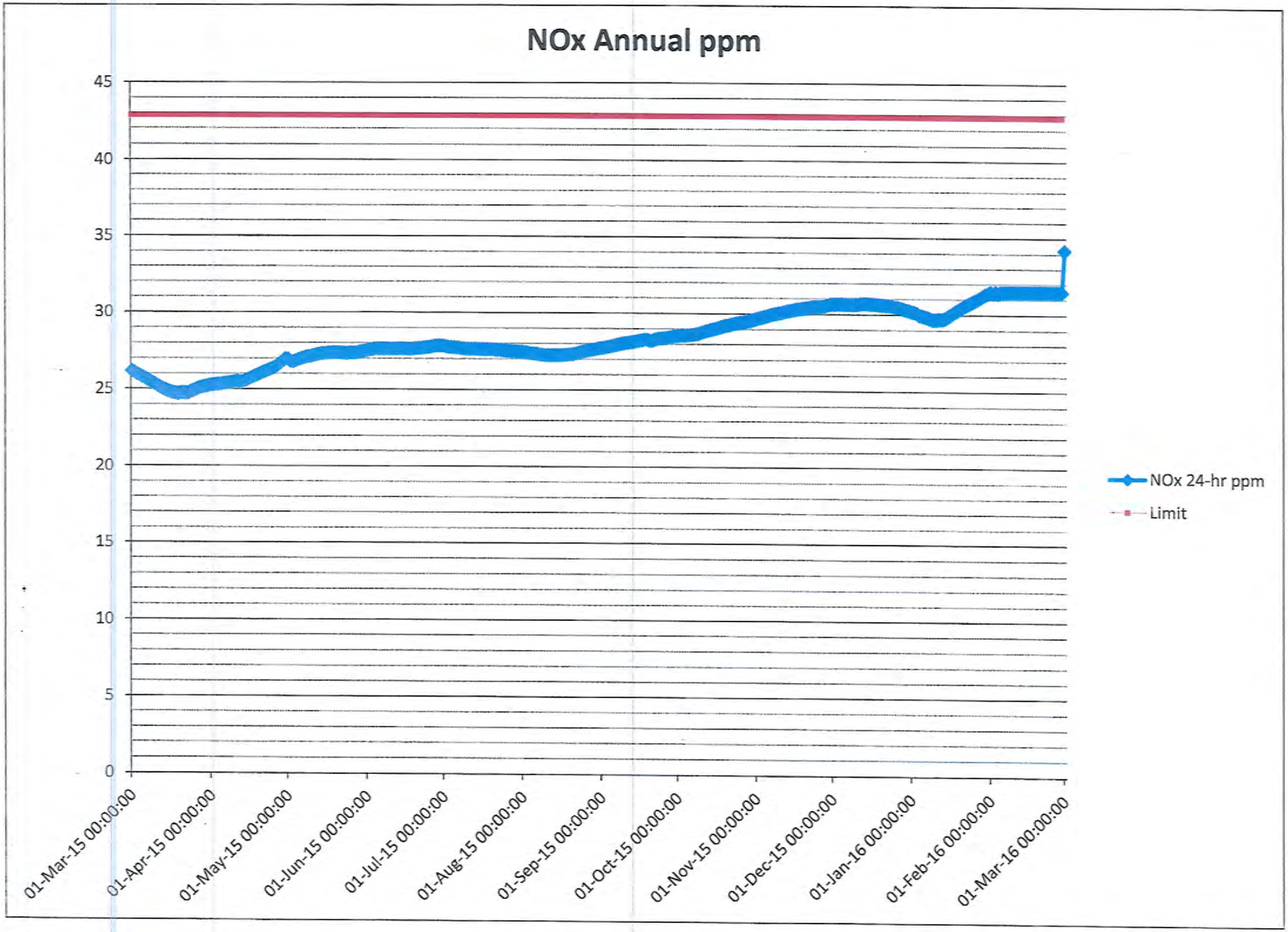
MOTIVA CD CEMS ANALYZER LIST

Total	Unit	Type	Analyzer Tag Number	Service	Manuf. / Model	Serial No.	Analyzer Range
29	FCCU3	SO2	428AT3709A	CO Boiler Stack	Ultramat 6E	T7 - 127; Sample System S/N Z14282	CEMs
30	FCCU3	NOx	428AT3709B	CO Boiler Stack	Noxmat 600	S07067	CEMs
31	FCCU3	O2	428AT3709C	CO Boiler Stack	Oxymat 6E	T7 - 129	CEMs
32	FCCU3	CO	428AT3709D	CO Boiler Stack	Ultramat 6E	T7 - 127 (SO2 & CO same)	CEMs
53	TGTU1	SO2	214AT8004A	Incinerator	Hartmann Braun / RADAS 2/1.2	SN 3.200152.4, PN 20713-0-2111134, PO 139291-62	CEMs
54	TGTU1	O2	214AT8004C	Incinerator	Hartmann Braun / MAGNOS 6G/5.0	SN 3.210357.3, PN 21123-0-7601100, PO 139291-61	CEMs
55	TGTU2	SO2	214AT8315A	Incinerator	Hartmann Braun / RADAS 2/1.2	SN 3.200167.4, PN 20713-0-2111134, PO 139291-64	CEMs
56	TGTU2	O2	214AT8315C	Incinerator	Hartmann Braun / MAGNOS 6G/5.0	SN 3.210367.3, PN 21123-0-7401100, PO 139291-63	CEMs

Appendix 5

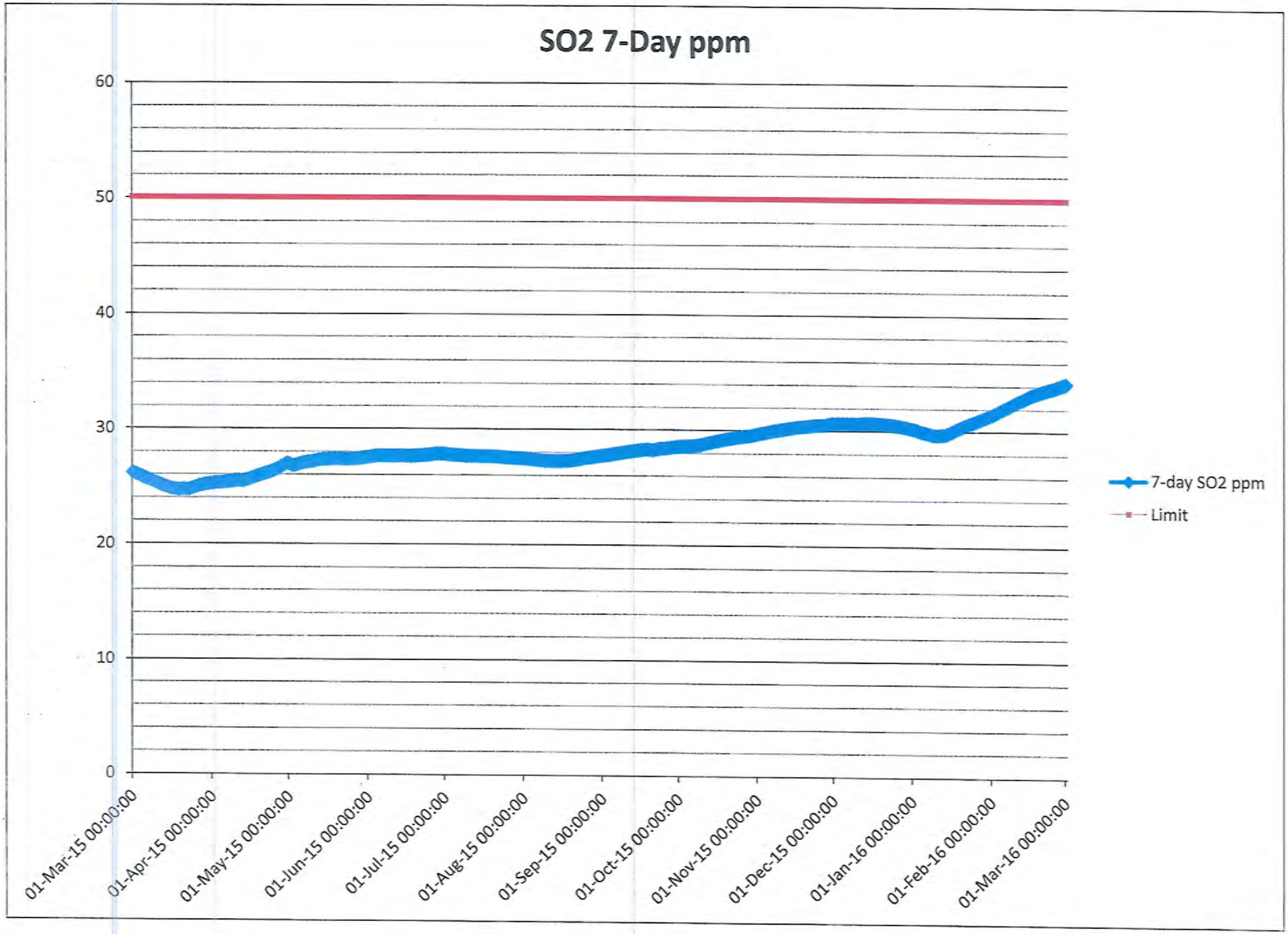
RCCU NO_x emission trends

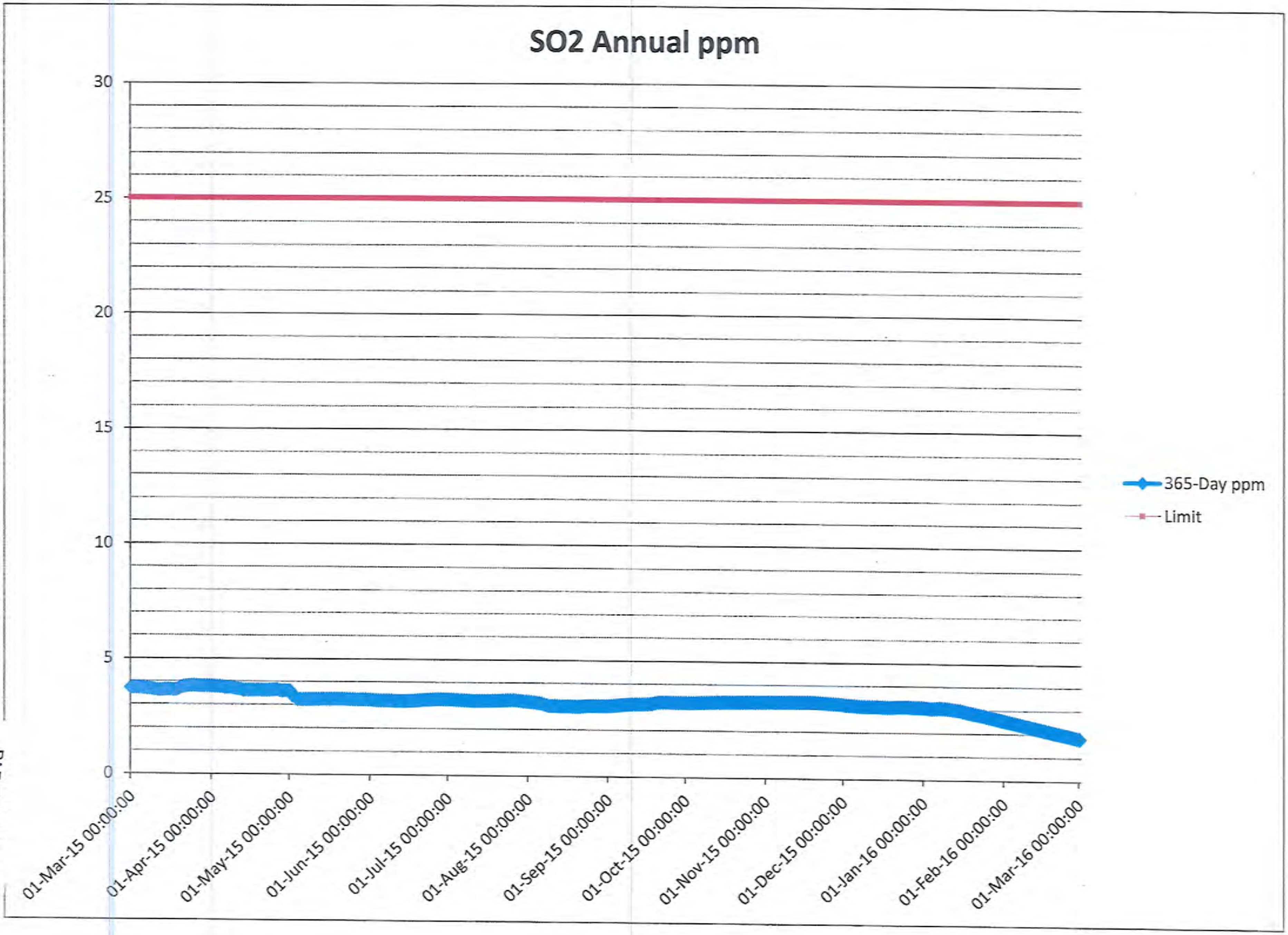

NOx 24-hr ppm
80
70
60
50
40
30
20
10
0
01-Mar-15 00:00:00
01-Apr-15 00:00:00
01-May-15 00:00:00
01-Jun-15 00:00:00
01-Jul-15 00:00:00
01-Aug-15 00:00:00
01-Sep-15 00:00:00
01-Oct-15 00:00:00
01-Nov-15 00:00:00
01-Dec-15 00:00:00
01-Jan-16 00:00:00
01-Feb-16 00:00:00
01-Mar-16 00:00:00
NOx 24-hr ppm
Limit


NOx Annual ppm
45
40
35
30
25
20
15
10
5
0
01-Mar-15 00:00:00
01-Apr-15 00:00:00
01-May-15 00:00:00
01-Jun-15 00:00:00
01-Jul-15 00:00:00
01-Aug-15 00:00:00
01-Sep-15 00:00:00
01-Oct-15 00:00:00
01-Nov-15 00:00:00
01-Dec-15 00:00:00
01-Jan-16 00:00:00
01-Feb-16 00:00:00
01-Mar-16 00:00:00
NOx 24-hr ppm
Limit

Appendix 6

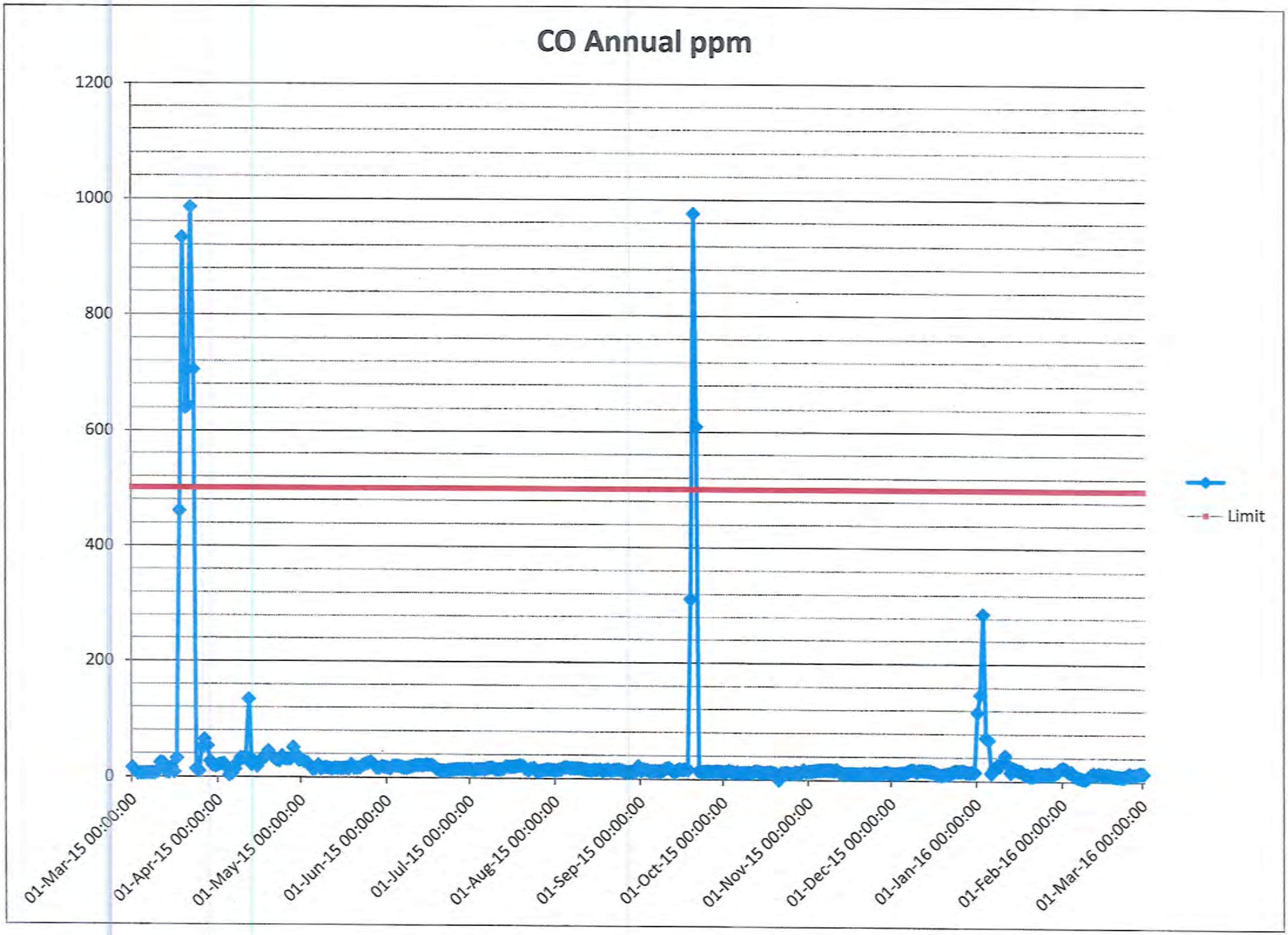
RCCU SO_2 emission trend


SO2 7-Day ppm
60
50
40
30
20
10
0
01-Mar-15 00:00:00
01-Apr-15 00:00:00
01-May-15 00:00:00
01-Jun-15 00:00:00
01-Jul-15 00:00:00
01-Aug-15 00:00:00
01-Sep-15 00:00:00
01-Oct-15 00:00:00
01-Nov-15 00:00:00
01-Dec-15 00:00:00
01-Jan-16 00:00:00
01-Feb-16 00:00:00
01-Mar-16 00:00:00
7-day SO2 ppm
Limit


SO2 Annual ppm
30
25
20
15
10
5
0
01-Mar-15 00:00:00
01-Apr-15 00:00:00
01-May-15 00:00:00
01-Jun-15 00:00:00
01-Jul-15 00:00:00
01-Aug-15 00:00:00
01-Sep-15 00:00:00
01-Oct-15 00:00:00
01-Nov-15 00:00:00
01-Dec-15 00:00:00
01-Jan-16 00:00:00
01-Feb-16 00:00:00
01-Mar-16 00:00:00
365-Day ppm
Limit

Appendix 7

RCCU CO emission trend


CO Annual ppm
1200
1000
800
600
400
200
0
01-Mar-15 00:00:00
01-Apr-15 00:00:00
01-May-15 00:00:00
01-Jun-15 00:00:00
01-Jul-15 00:00:00
01-Aug-15 00:00:00
01-Sep-15 00:00:00
01-Oct-15 00:00:00
01-Nov-15 00:00:00
01-Dec-15 00:00:00
01-Jan-16 00:00:00
01-Feb-16 00:00:00
01-Mar-16 00:00:00
Limit

Appendix 8

BWON schematic

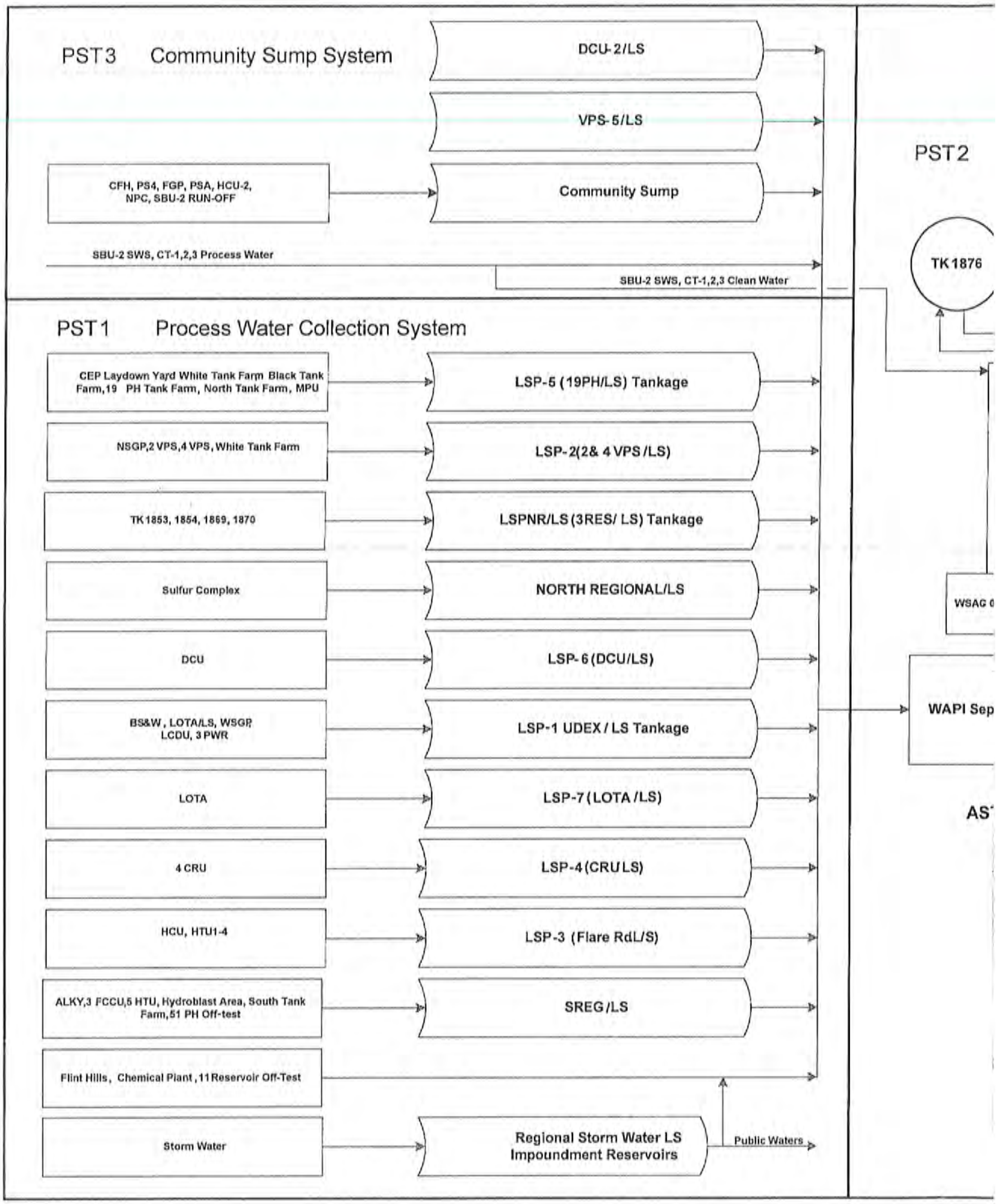
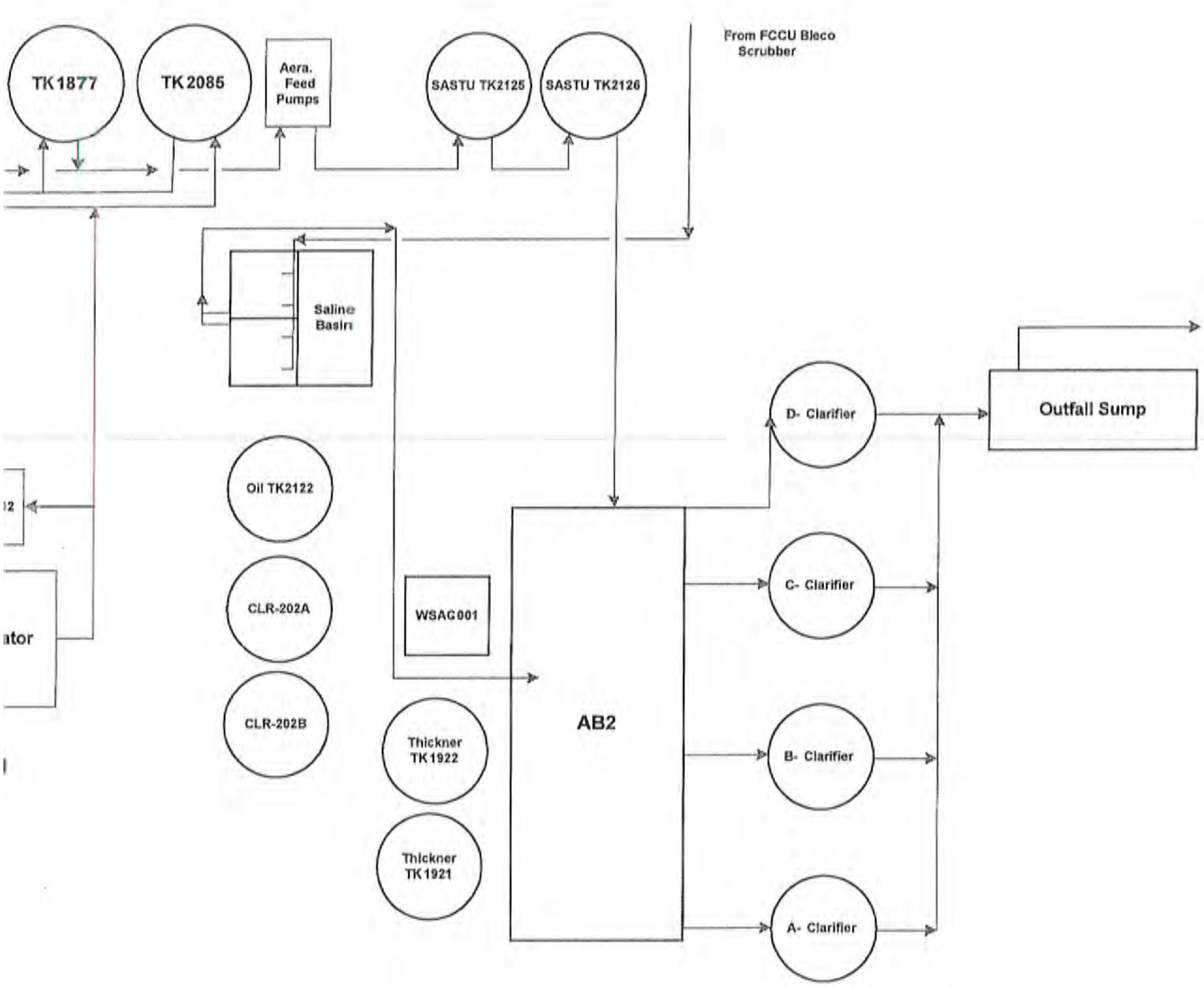


Figure 1.1 Flow

Process Water Treatment System



agram for PWTS

PAR EPA2016AUDITCD
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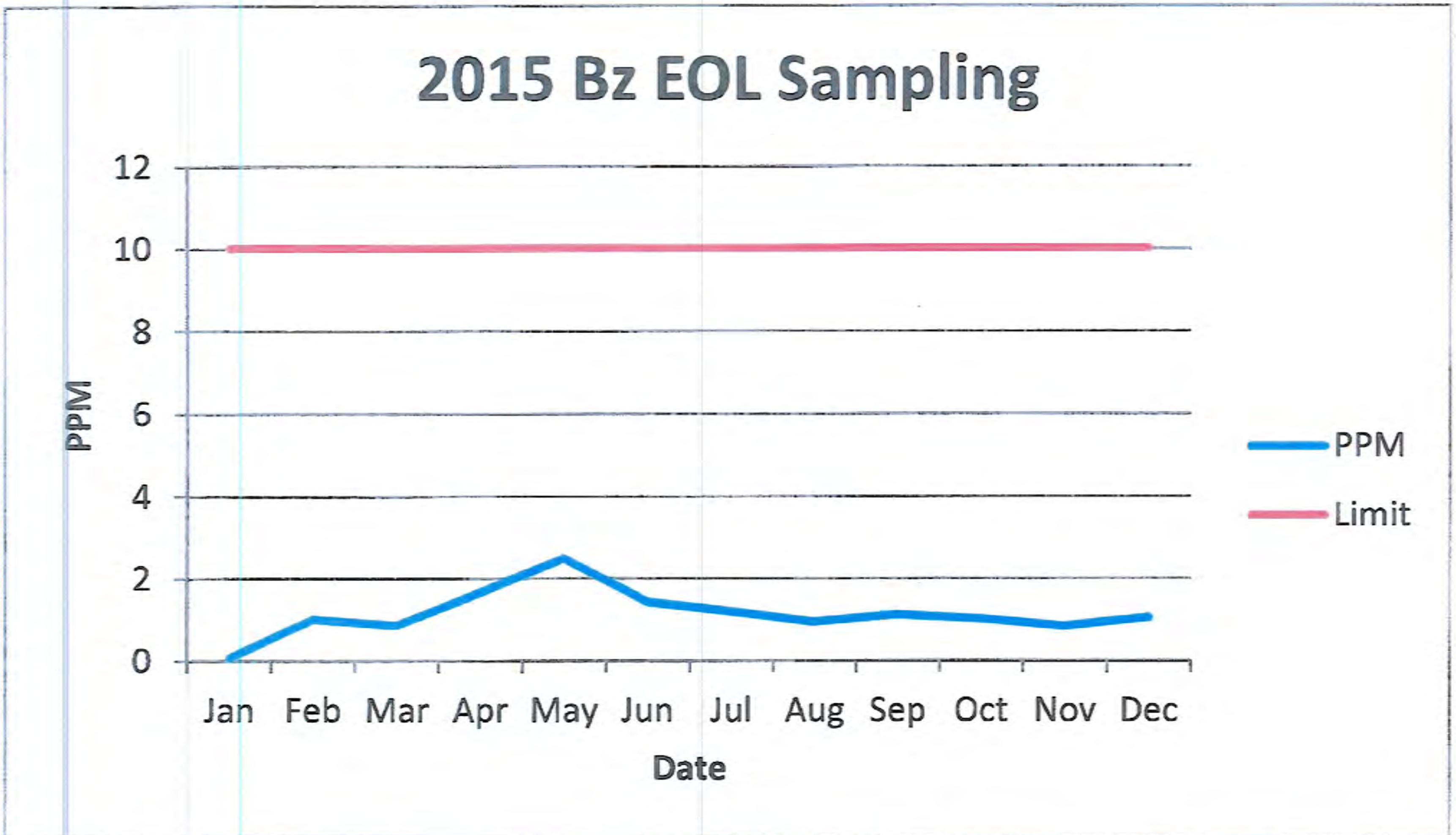
Appendix 9

BWON analytical data for feed



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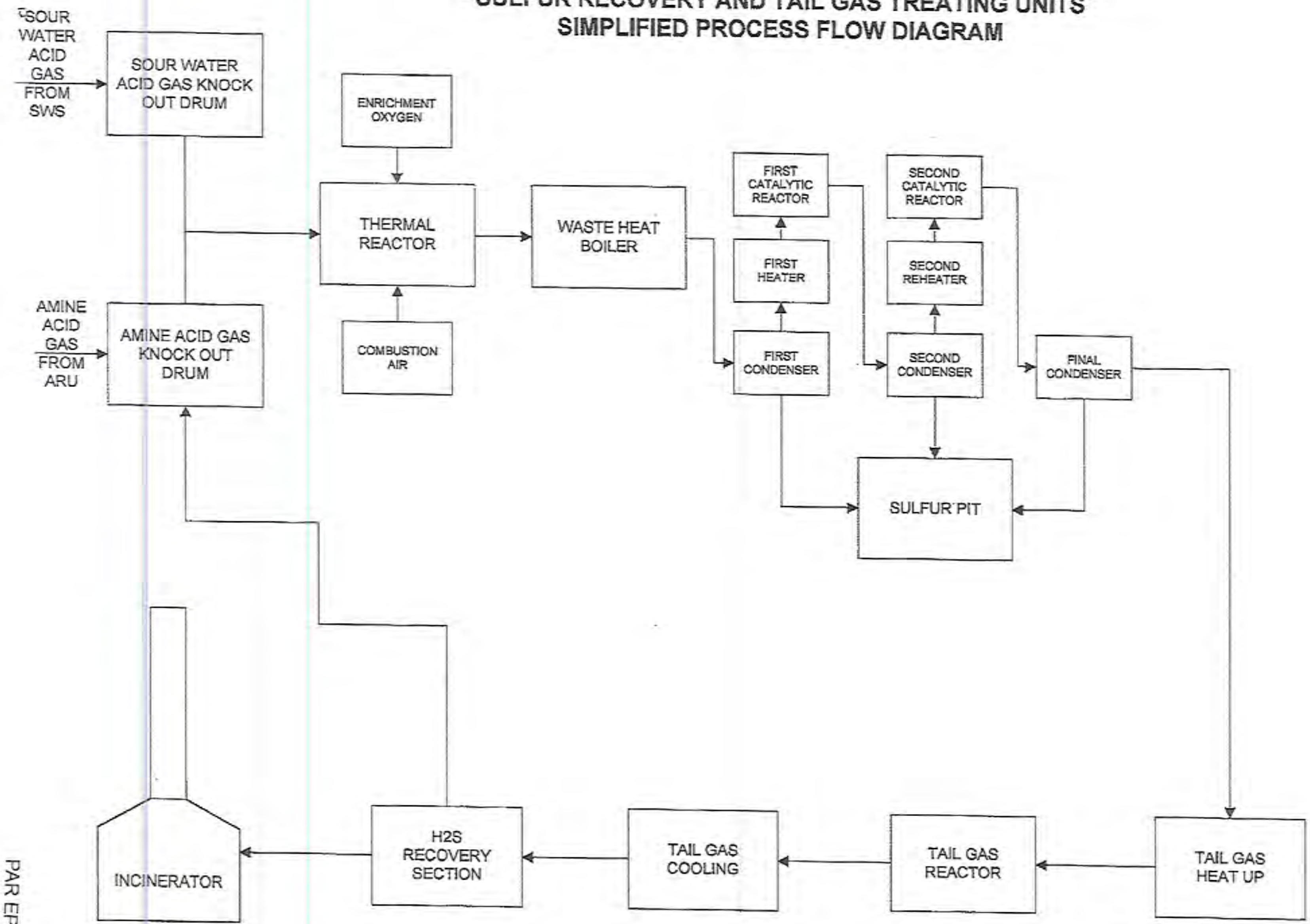
Appendix 10

SRU block flow diagram

SULFUR RECOVERY AND TAIL GAS TREATING UNITS SIMPLIFIED PROCESS FLOW DIAGRAM



Appendix 11

SRU SO_2 emission trends


SBU 1 SO2 ppm 2015-16
0
50
100
150
200
250
300
350
400
3/1/15 0:00
4/1/15 0:00
5/1/15 0:00
6/1/15 0:00
7/1/15 0:00
8/1/15 0:00
9/1/15 0:00
10/1/15 0:00
11/1/15 0:00
12/1/15 0:00
1/1/16 0:00
2/1/16 0:00
3/1/16 0
TGTU1 SO2
TGTU 2 SO2

Appendix 12

Compressor inlet/outlet flows and spill back

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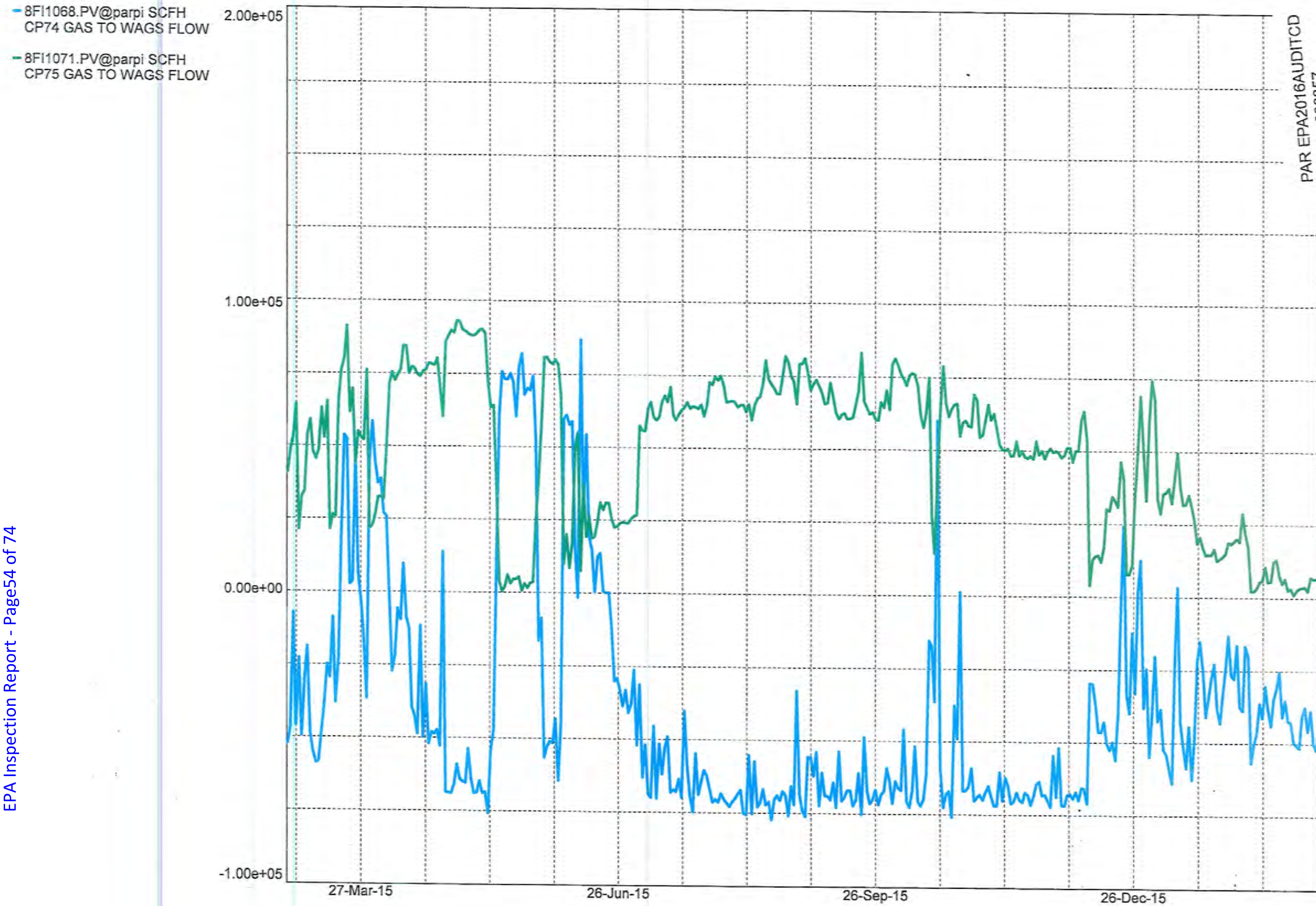
Page 1

FGR 1



PAR EPA2016AUDITCD
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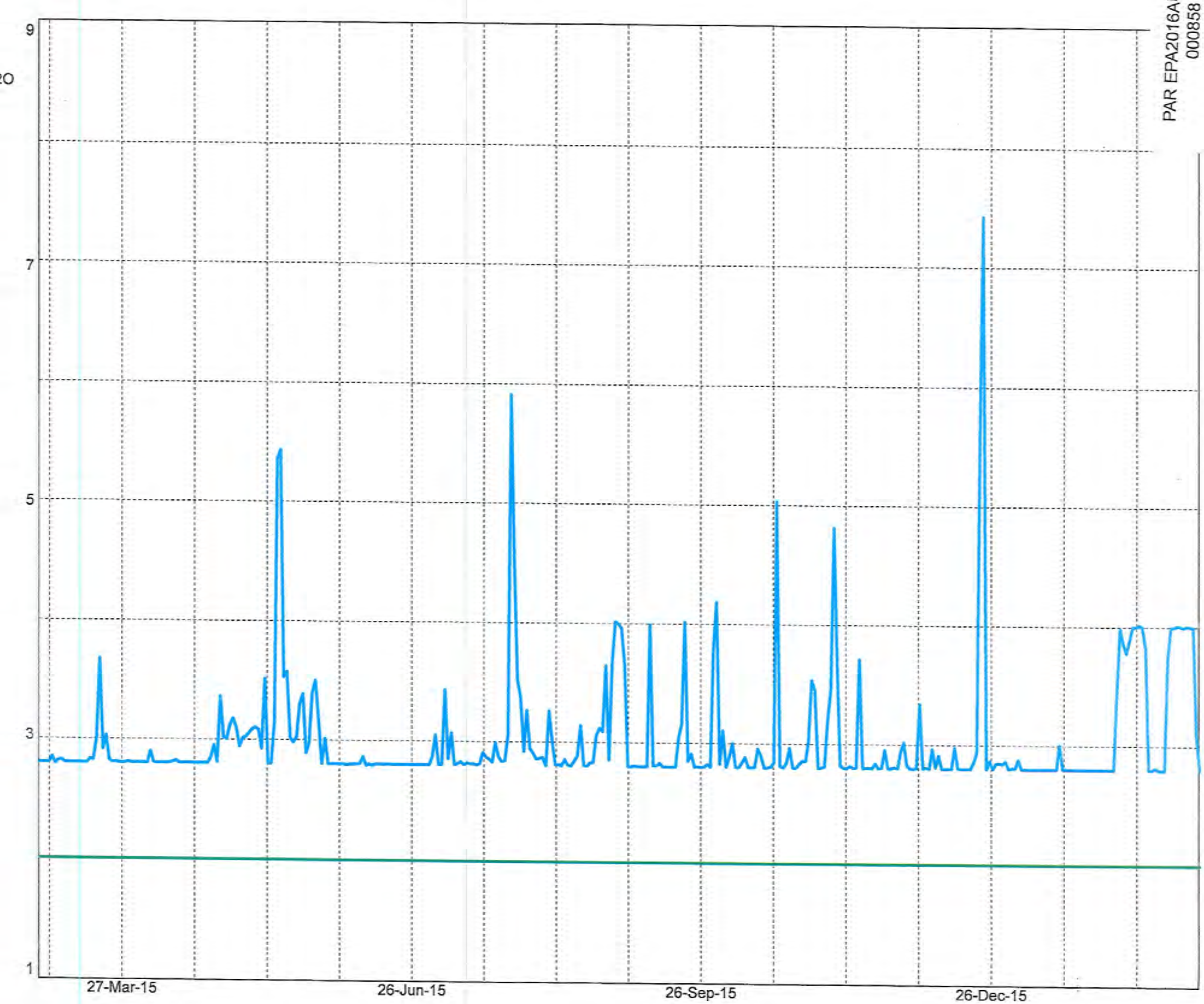
Page 1

FGR1



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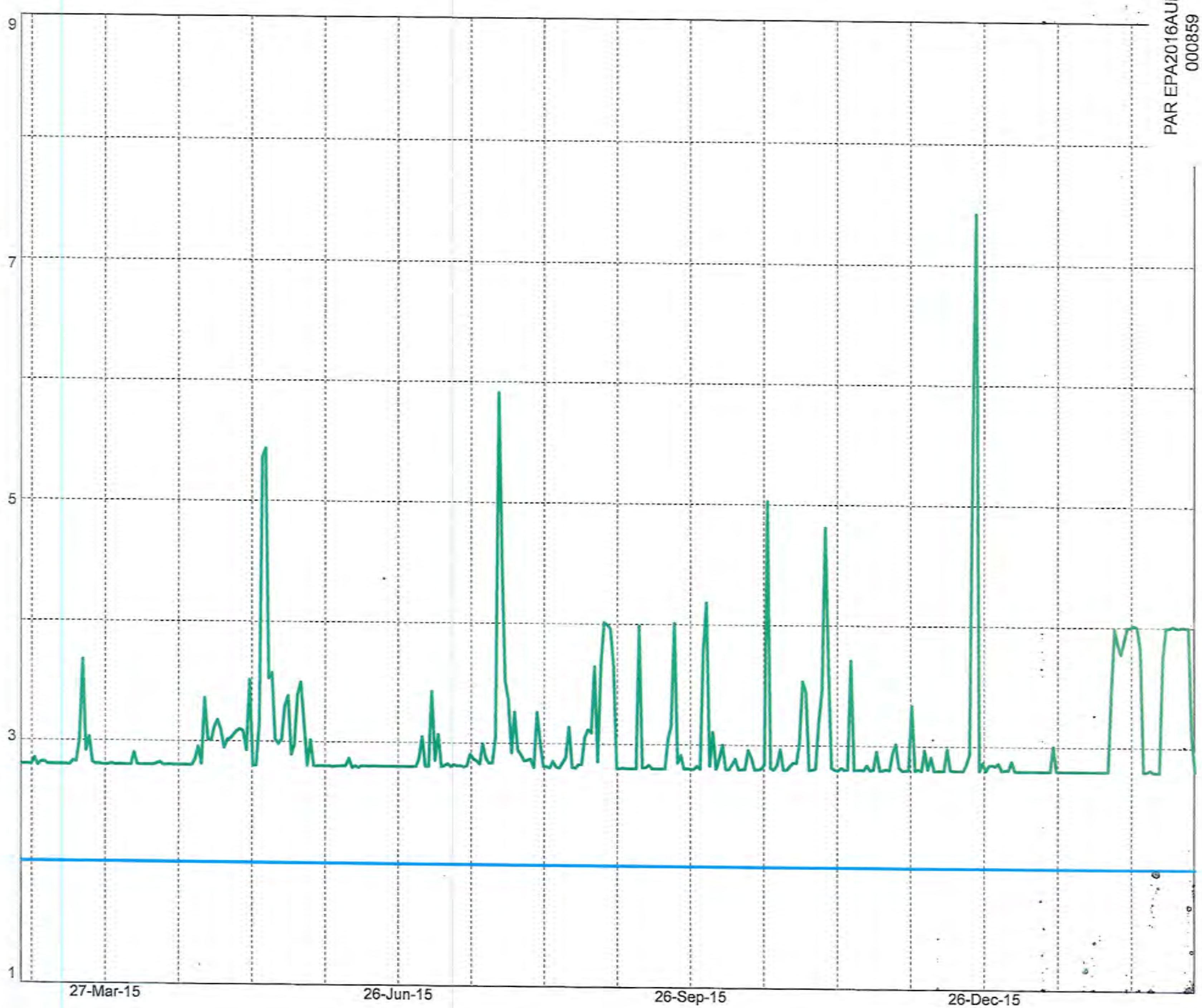
Page 1

FGR1

- 8PC1033.TGT_LO@parpi INH2O M COMPS GAS HEADER
- 8PC1033.PV@parpi INH2O M COMPS GAS HEADER



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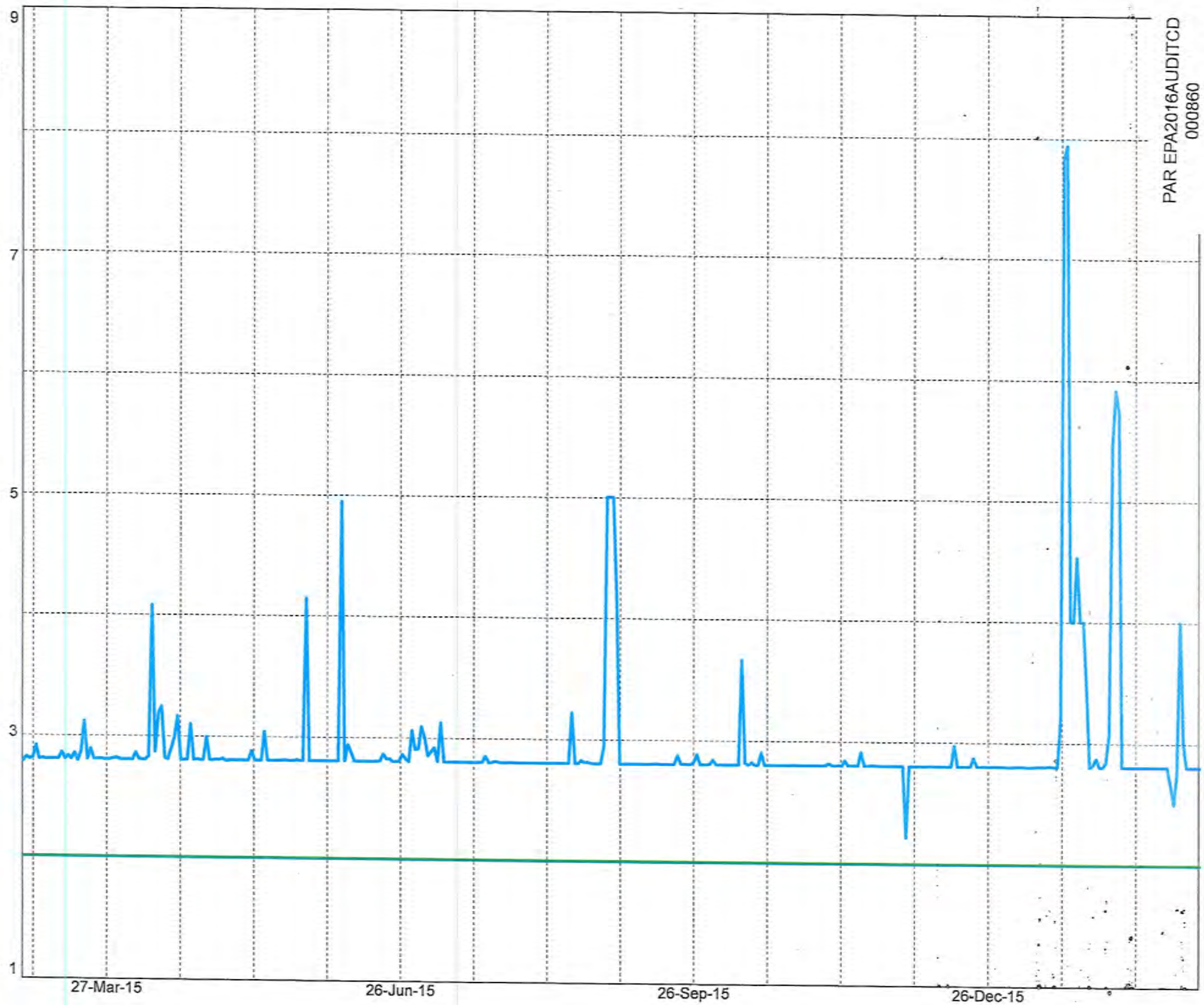
Page 1

FGR2

- 8PC1214.PV@parpi INH2O M COMPS SPILLBACK GAS
- 8PC1214.TGT_LO@parpi INH2O M COMPS SPILLBACK GAS



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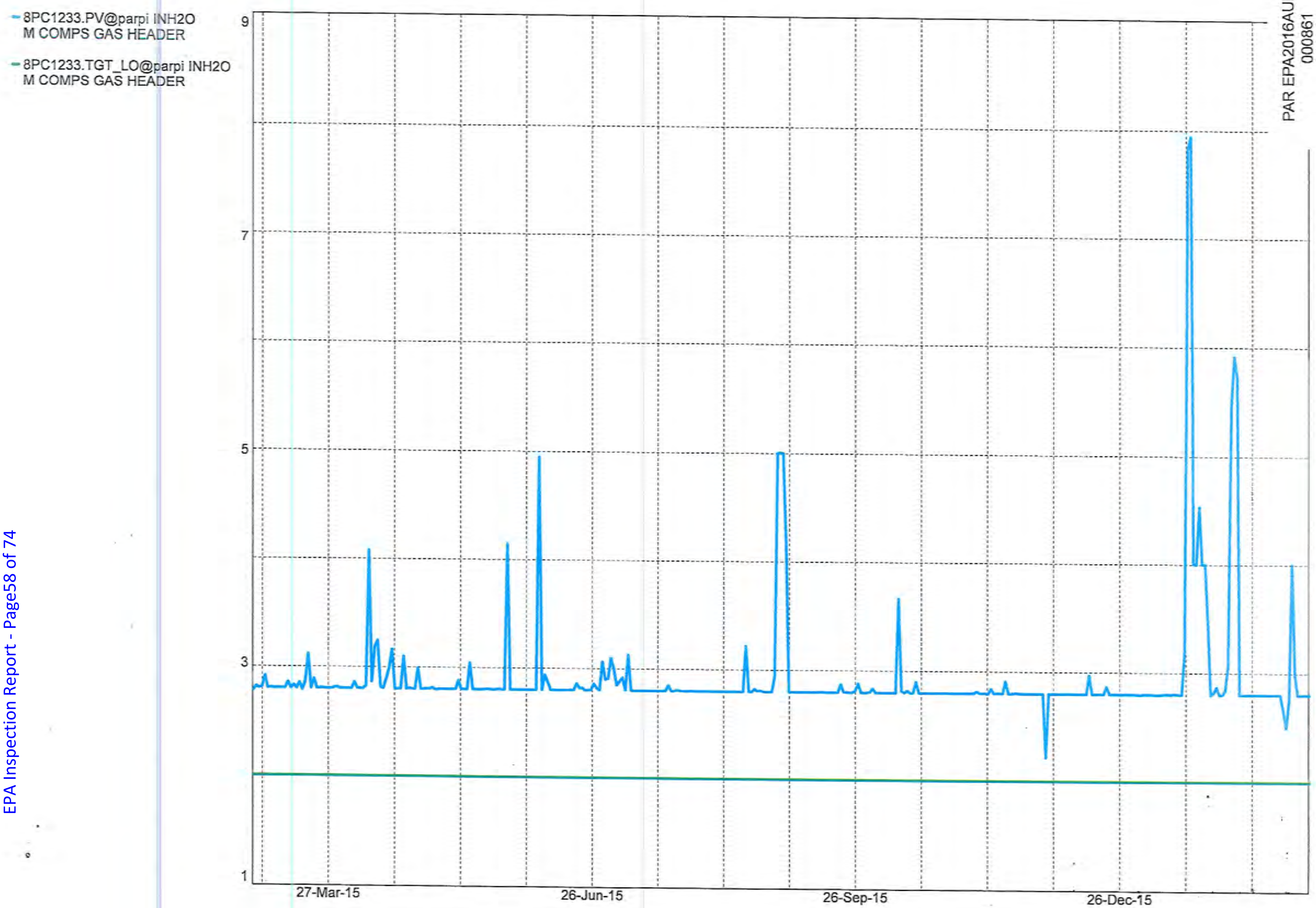
Page 1

FGR 2



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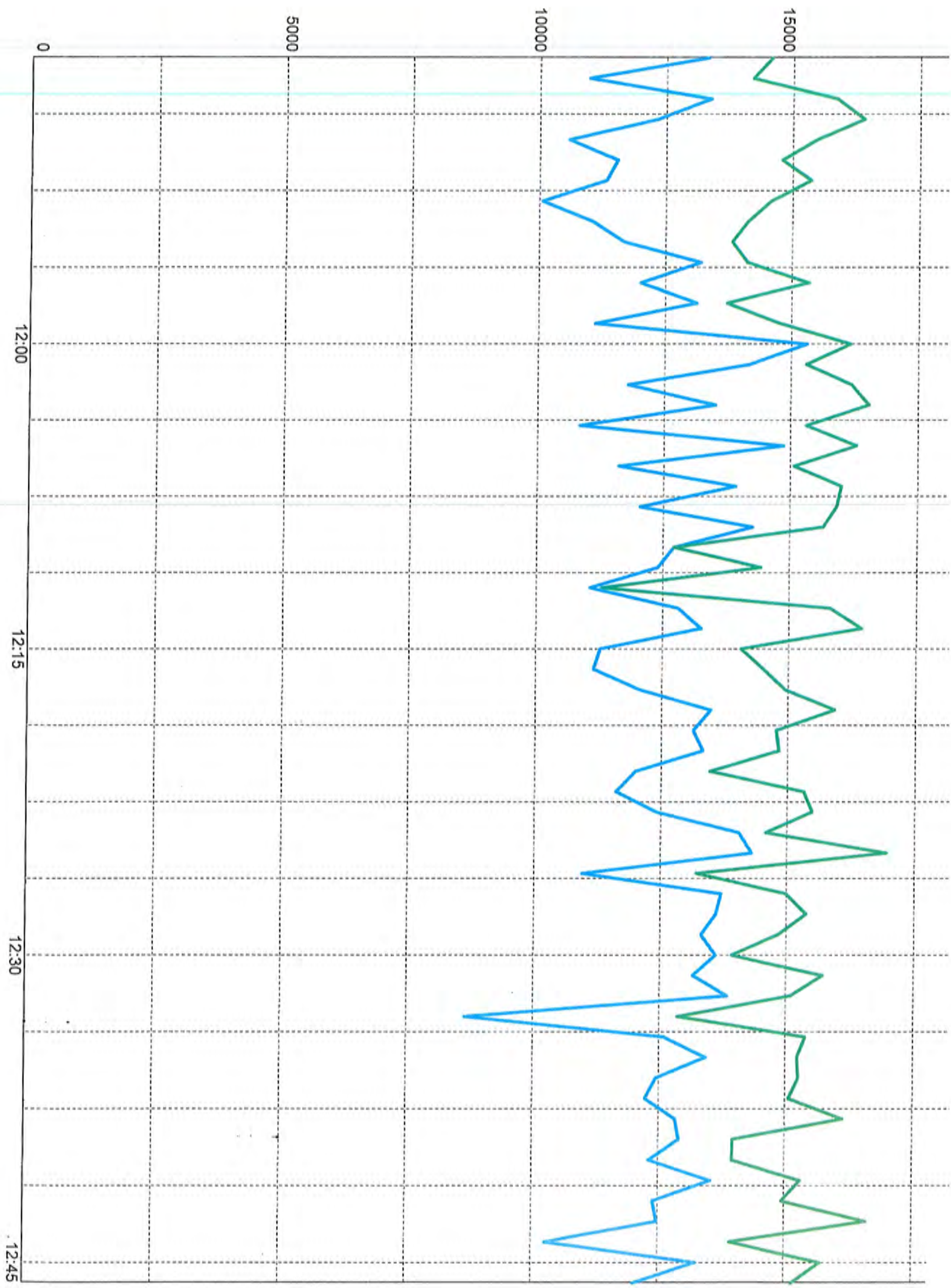
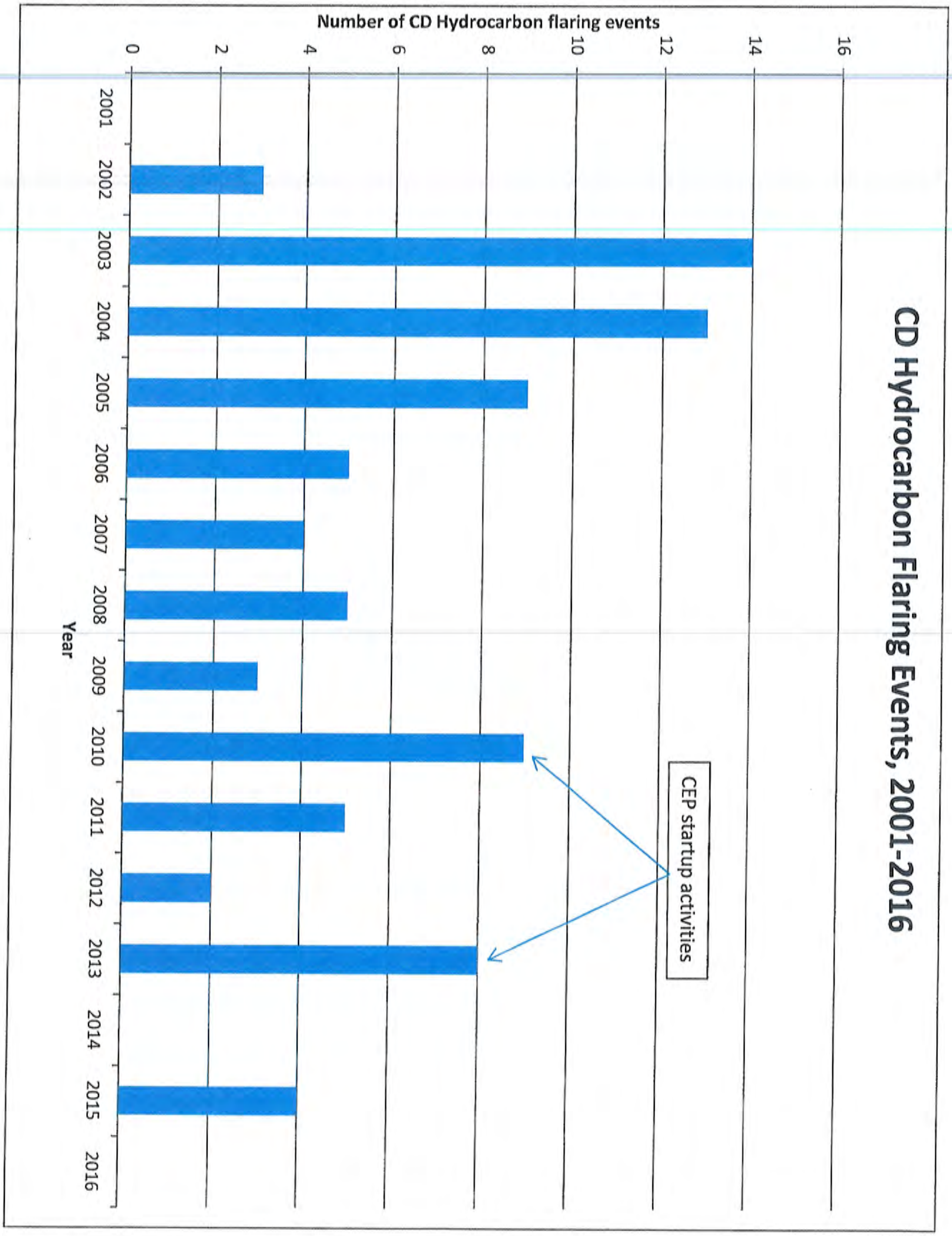

0
5000
10000
15000
12:00
12:15
12:30
12:45

Appendix 13

Acid gas and hydrocarbon flaring events


CD Hydrocarbon Flaring Events, 2001-2016
Number of CD Hydrocarbon flaring events
0
2
4
6
8
10
12
14
16
Year
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
CEP startup activities

Consent Decree
Acid Gas & Hydrocarbon Flaring Incidents
2001 - 2015

Type of Flaring	Incident Date
Acid Gas Flaring	12/12/2001
Acid Gas Flaring	7/12/2002
Acid Gas Flaring	10/15/2003
Acid Gas Flaring	10/15/2003
Acid Gas Flaring	10/22/2004
Acid Gas Flaring	10/27/2004
Acid Gas Flaring	10/27/2004
Acid Gas Flaring	10/27/2004
Acid Gas Flaring	8/26/2005
Acid Gas Flaring	12/7/2005
Acid Gas Flaring	4/8/2007
Acid Gas Flaring	4/8/2007
Acid Gas Flaring	7/7/2008
Acid Gas Flaring	12/28/2009
Acid Gas Flaring	12/28/2009
Hydrocarbon Flaring	2/27/2002
Hydrocarbon Flaring	5/13/2002
Hydrocarbon Flaring	11/17/2002
Hydrocarbon Flaring	4/14/2003
Hydrocarbon Flaring	4/14/2003
Hydrocarbon Flaring	4/14/2003
Hydrocarbon Flaring	4/14/2003
Hydrocarbon Flaring	4/14/2003
Hydrocarbon Flaring	4/15/2003
Hydrocarbon Flaring	9/15/2003
Hydrocarbon Flaring	9/15/2003
Hydrocarbon Flaring	10/14/2003
Hydrocarbon Flaring	10/14/2003
Hydrocarbon Flaring	10/14/2003
Hydrocarbon Flaring	10/15/2003
Hydrocarbon Flaring	10/15/2003
Hydrocarbon Flaring	10/15/2003
Hydrocarbon Flaring	5/1/2004
Hydrocarbon Flaring	5/1/2004
Hydrocarbon Flaring	5/1/2004
Hydrocarbon Flaring	5/1/2004
Hydrocarbon Flaring	8/25/2004
Hydrocarbon Flaring	10/20/2004
Hydrocarbon Flaring	10/20/2004
Hydrocarbon Flaring	10/20/2004

Consent Decree
Acid Gas & Hydrocarbon Flaring Incidents
2001 - 2015

Type of Flaring	Incident Date
Hydrocarbon Flaring	10/20/2004
Hydrocarbon Flaring	10/20/2004
Hydrocarbon Flaring	10/22/2004
Hydrocarbon Flaring	10/27/2004
Hydrocarbon Flaring	12/22/2004
Hydrocarbon Flaring	3/9/2005
Hydrocarbon Flaring	3/9/2005
Hydrocarbon Flaring	3/9/2005
Hydrocarbon Flaring	11/1/2005
Hydrocarbon Flaring	11/2/2005
Hydrocarbon Flaring	11/9/2005
Hydrocarbon Flaring	11/9/2005
Hydrocarbon Flaring	11/9/2005
Hydrocarbon Flaring	12/7/2005
Hydrocarbon Flaring	1/24/2006
Hydrocarbon Flaring	1/24/2006
Hydrocarbon Flaring	2/14/2006
Hydrocarbon Flaring	2/14/2006
Hydrocarbon Flaring	3/29/2006
Hydrocarbon Flaring	2/6/2007
Hydrocarbon Flaring	3/26/2007
Hydrocarbon Flaring	3/26/2007
Hydrocarbon Flaring	3/26/2007
Hydrocarbon Flaring	6/2/2008
Hydrocarbon Flaring	9/11/2008
Hydrocarbon Flaring	9/25/2008
Hydrocarbon Flaring	12/3/2008
Hydrocarbon Flaring	12/3/2008
Hydrocarbon Flaring	11/25/2009
Hydrocarbon Flaring	11/25/2009
Hydrocarbon Flaring	11/25/2009
Hydrocarbon Flaring	3/9/2010
Hydrocarbon Flaring	3/9/2010
Hydrocarbon Flaring	4/11/2010
Hydrocarbon Flaring	4/11/2010
Hydrocarbon Flaring	5/12/2010
Hydrocarbon Flaring	5/12/2010
Hydrocarbon Flaring	5/12/2010
Hydrocarbon Flaring	7/20/2010
Hydrocarbon Flaring	7/20/2010
Hydrocarbon Flaring	2/15/2011

Consent Decree
Acid Gas & Hydrocarbon Flaring Incidents
2001 - 2015

Type of Flaring	Incident Date
Hydrocarbon Flaring	2/15/2011
Hydrocarbon Flaring	5/1/2011
Hydrocarbon Flaring	5/1/2011
Hydrocarbon Flaring	12/12/2011
Hydrocarbon Flaring	2/7/2012
Hydrocarbon Flaring	5/12/2012
Hydrocarbon Flaring	4/14/2013
Hydrocarbon Flaring	4/14/2013
Hydrocarbon Flaring	4/14/2013
Hydrocarbon Flaring	4/25/2013
Hydrocarbon Flaring	6/3/2013
Hydrocarbon Flaring	6/3/2013
Hydrocarbon Flaring	7/10/2013
Hydrocarbon Flaring	7/10/2013
Hydrocarbon Flaring	2/21/2015
Hydrocarbon Flaring	5/15/2015
Hydrocarbon Flaring	9/19/2015
Hydrocarbon Flaring	9/21/2015

Appendix 14

Operating permit excerpts

JDC

JD Consulting, L.P.

404 Camp Craft Road
Austin, Texas 78746

512-347-7588
fax - 512-347-8243

June 20, 2006

Mr. Scott Poole
Texas Commission on Environmental Quality
Air Permits Division (MC 163)
Office of Permitting, Remediation, and Registration
P.O. Box 13087
Austin, TX 78711-3087

Re: Consolidation of Application and Supplements
Motiva Enterprises LLC
Amendment and Renewal of Permit No. 8404
Port Arthur, Jefferson County
Account No. JE-0095-D
CN600124051; RN100209451

Dear Mr. Poole:

On behalf of Motiva Enterprises LLC (Motiva), JD Consulting, L.P. (JDC) is submitting the enclosed consolidation of the permit application submitted on January 26, 2006 with supplements submitted through June 19, 2006. This consolidation is being submitted solely for ease of reference. The consolidation was produced simply by replacing pages from the application with those from the supplements. No changes to the application were made in the course of this consolidation.

We wish to thank you in advance for your consideration of this application. If you have any questions, please feel free to contact me at (512) 347-7588 or Ms. Rebecca Demeter (Motiva) at (409) 989-7174.

Sincerely,

JD CONSULTING, L.P.

J L Montgomery

Les Montgomery, P.E.
Principal

STATE OF TEXAS
J. L. MONTGOMERY
51616
REGISTERED
PROFESSIONAL ENGINEER

6/20/06

JLM/mlg
Enclosures

cc: Ms. Georgie Volz, Regional Manager, TCEQ Region 10 – Beaumont
Ms. Bonnie Braganza, EPA Region 6 - Dallas
Ms. Rebecca Demeter, Motiva Enterprises LLC

PAR EPA2016AUDITCD
000047

Draft – March 12, 2012

Mr. Mike Wilson, P.E.
Division Director
Air Permits Division (MC 163)
Office of Permitting, Remediation, and Registration
Texas Commission on Environmental Quality (TCEQ)
P.O. Box 13087
Austin, TX 78711-3087

Re: Permit Amendment – Permit No. 6056
Crude Expansion Project – As Built Update
Motiva Enterprises, LLC
Port Arthur Refinery
Port Arthur, Jefferson County, Texas
RN100209451
CN600124051
BLIND: ENV 2.F.12

Dear Mr. Wilson:

Enclosed is a permit amendment application to Permits No. 6056 and 8404 to correct the number and corresponding emissions from fugitive components associated with the Crude Expansion Project (CEP) and affected sources at the Base Plant. Also included in this application are the results of an analysis of project changes pursuant to the EPA aggregation policy. Netting calculations involving project increases and decreases at the Port Arthur Refinery (PAR) Base Plant and CEP are included, demonstrating that had Motiva known at the time of the original 2006 Consolidated Application the correct number of fugitive components, Motiva would have provided appropriate commitments in conjunction with the project to have netted out in accordance with the 2006 NNSR requirements. Accordingly, this application constitutes a retrospective federal new source review for the CEP.

Separate identical copies of the application are being submitted concurrently, one for Permit No. 6056 and one for Permit No. 8404 because amendments to both permits are necessary to accomplish the retrospective review. This letter transmits the amendment application for Permit No. 6056 with original signatures on appropriate forms related to that permit.

The proposed allowable emission increases for Permit No. 6056 are all less than the de minimis levels listed in 30 TAC §39.402(a)(3)(B). Therefore, public notice is not required for this project. The emission increase determinations are based on the assumption that the Permit 6056 project pending approval as of the date this application is submitted will be issued before this project is processed by TCEQ.

If you should have any questions concerning this request, please contact Ms. Brenda J. Allen of Motiva at (409) 989-7649 or Mr. Les Montgomery of RPS at (512) 347-7588.

Sincerely,

Motiva Enterprises, LLC

Greg Willms
General Manager
Motiva Enterprises, LLC

Enclosures

cc: Ms. Kathryn Sauceda, Air Section Manager, TCEQ Region 10
Mr. Les Montgomery, RPS

charge/production rate by more than 15 percent in any 24-hour period, the holder of this permit shall perform stack sampling and other testing as required, in accordance with Special Condition No. 31, to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the combustion sources listed in Attachment 6.

33. The Reformer Regeneration Vent (EPN SCRU4-2) is subject to the following requirements:

A. The vent shall be routed through a caustic scrubber prior to discharge to the atmosphere. The scrubber shall be designed to control hydrogen chloride (HCl) emissions to an outlet concentration of 10 ppmv or an overall control efficiency of 99 percent, whichever is less stringent.

B. The scrubbing solution shall be maintained at or above a pH of 7.0 and analyzed once daily with a pH meter.

C. The inlet and outlet HCl emissions shall be tested daily with an approved portable analyzer.

D. Records of the analytical and testing results and the actual testing methods used shall be maintained at the plant site for a period of five years and made available to the TCEQ Executive Director or his designated representative upon request.

Continuous Determination Of Compliance

34. The holder of this permit shall install, calibrate, operate, and maintain CEMSs to measure and record the following:

A. The NO_x, and O_2 from the No. 4 CRU Heater Stack (EPN SCRU4-1) and the No. 2 Vacuum Pipe Still combined heater stack (EPN VPS2-1);

B. The NO_x, CO, O_2, and SO_2 from the FCCU Regenerator (EPN SFCCU3-2); and

C. H_2S in representative locations in the refinery fuel gas system in accordance with the fuel sulfur monitoring requirements of 40 CFR § 60.105. **(10/13)**

35. The CEMS shall meet the following requirements:

A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

B. Section 1 below applies to sources subject to the quality-assurance requirements of 40 CFR Part 60, Appendix F; Section 2 applies to all other sources:

(1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, § 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.

(2) The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2, with the following exception: a relative accuracy test audit (RATA) is **not** required once every four quarters (i.e., four successive quarterly CGA may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months.

All CGA exceedances of $\pm$15 percent accuracy indicate that the CEMS is out of control.

C. The monitoring data shall be reduced to hourly average concentrations at least once every day, using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of pounds/hour at least once every week in accordance with Attachment 3 of these conditions, entitled "Calculation of Emission Rates from CEMS Data."

D. All monitoring data and quality assurance data shall be maintained by the source. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

E. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required RATA in order to provide them the opportunity to observe the testing.

F. Quality-assured (or valid) data must be generated when the facility generating emissions is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the facility generating emissions operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgement and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

36. The holder of this permit shall install, calibrate, operate, and maintain a continuous opacity monitoring system (COMS) to measure and record the opacity from the FCCU Regenerator (EPN SFCCU3-2). An approved alternate monitoring plan for opacity pursuant to 40 CFR Part 60, Subpart J and/or 40 CFR Part 63, Subpart UUU may be used in lieu of a COMS on the FCCU Regenerator. The COMS monitoring system shall meet the following requirements:

A. The COMS shall meet 40 CFR Part 60, Appendix B Performance Specification No 1.

B. The COMS shall meet the requirements of 40 CFR § 60.13. The appropriate TCEQ Regional Manager will be the administrator for alternate monitoring requests, except where the monitoring is also required by an applicable NSPS, 40 CFR Part 60 or NESHAP, 40 CFR Part 61 or 40 CFR Part 63, where EPA Region 6 remains the administrator for alternate monitoring requests. Alternate monitoring requests should be submitted to the appropriate TCEQ Regional Director and EPA Region 6, when they are the administrator, with copies to any local air pollution programs.

C. Monitoring data shall be recorded and maintained as specified in 40 CFR § 60.7(c), (d), (e), and (f).

D. The appropriate TCEQ Regional Office and any local air pollution programs shall be notified at least 30 days prior to any required initial performance evaluation.

E. Quality-assured (or valid) data must be generated when the FCCU is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the FCCU is operated over the previous rolling 12-month period.

Emission Compliance Recordkeeping

37. Records of all compliance testing, CEM results, process parameters (including short-term production rates, firing rates, etc.), and any other data used to demonstrate compliance with emission rate limitations shall be maintained on-site for a period of five years and made available to designated representatives of TCEQ upon request.

Emission calculations to demonstrate compliance with the annual emission rate limitations, which are on a 12-month rolling average basis, shall be performed at least once every calendar quarter. Demonstration of compliance shall be based on the emission calculation methods described below.

A. Tanks:

(1) Routine emissions shall be calculated based on AP-42, Chapter 7 (Fifth Edition), using the physical property data of the material stored and the actual tank configuration. Short-term emission rates shall be based on the maximum expected filling rate for fixed-roof tanks and the higher of the filling rate or withdrawal rate for internal and external floating roof tanks. Rolling 12-month emission rates shall be based on actual rolling 12-month throughput rates.

(2) Emissions from landing and refloating roofs of floating roof tanks for purposes of planned maintenance shall be calculated using API Technical Report 2567, "Evaporative Loss from Storage Tank Floating Roof Landings," dated April 2005. These emissions shall be increased as provided for by Equation No. 5 of the API report, taking into account the number of elapsed days after the tank roof is landed and until all sources of VOC vapor generation (including

(1) Isolate the leak.

(2) Commence repair or replacement of the leaking component.

(3) Use a leak collection or containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

C. The date and time of each inspection shall be recorded in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be maintained at the plant site for a period of five years and made available to the TCEQ Executive Director or his designated representative upon request.

Fluidized Catalytic Cracking Unit (FCCU)

19. The following applies to the FCCU regeneration vent/vent gas stack (EPN SFCCU3-2):

A. The maximum allowable concentration of the following pollutants in the FCCU vent gas stack (EPN SFCCU3-2) are:

Pollutant	Hourly	24-hr Avg.	Annual	Basis
CO	500 ppmv		500 ppmv	(dry, 0% O_2)
SO_2	157 ppmv	50 ppmv*	25 ppmv*	(dry, 0% O_2)
NO_x	109 ppmv	68 ppmv*	42.8 ppmv*	(dry, 0% O_2)
VOC	15 ppmv		15 ppmv	(dry)

* – These limits are required by EPA Consent Decree No. H-01-0978. The annual limits apply to rolling 365 day periods.

B. The total particulate matter (PM) emissions from the FCCU Vent Gas Stack (EPN SFCCU3-2) shall not exceed one pound per 1,000 pounds of coke burn-off.

Where:

Efficiency	=	sulfur recovery efficiency, percent
S recovered	=	S produced, Long tons per day (LTPD)
S acid gas	=	(S recovered plus S stack), LTPD
S stack	=	sulfur in the incinerator stack, LTPD

The average sulfur emission reduction efficiency (sulfur recovery efficiency) shall be demonstrated for each calendar day by a mass balance calculation using data obtained from the incinerator stack SO_2 monitor, sulfur production records, and other process data. Sulfur recovery efficiency shall be calculated for each day (not a monthly average), but the calculations may be performed monthly. Records of the sulfur recovery efficiency compliance calculations shall be maintained at the plant site for a period of five years and made available to representatives of the TCEQ upon request.

21. The SO_2 concentration in SRU incinerator vents (EPNs STGTU1-1, STGTU2-1, STGTU5-1, STGTU6-1, and STGTU7-1) shall not exceed 250 ppmv averaged over a 12-hour period. Records of the SO_2 in the incinerators' exhaust gas shall be maintained for five years and made available to representatives of the TCEQ upon request. **(05/12)**

22. Sour gas emissions from the sulfur pits, sulfur storage, and sulfur loading operations shall be collected by a vapor collection system and routed back to a SRU thermal reactor, to a TGTU, to a tail gas incinerator (TGI), or to a scrubber. During shutdown of the control device for maintenance, any emissions from the sulfur pits, sulfur storage, and sulfur truck-loading operations will be routed either to a redundant like control device or to an absorption media. Records of SRU downtime shall be maintained for a period of five years and made available to representatives of the TCEQ upon request. **(12/10)**

23. Each Amine Recovery Unit (ARU) shall use monoethanol amine, methyl diethanol amine, or diglycol amine. Changing to another H_2S contact solvent for normal operation will require a permit amendment and approval from the Executive Director of the TCEQ.

24. The SBU1 Rich Amine Charge Tanks shall be checked for hydrocarbons once per day from connections at the 15-foot and 10-foot levels and shall be hand gauged once per week. At least 13 feet of amine shall be held in the charge tanks at any given time.

    If hydrocarbons are discovered at or above the 15-foot level, steps shall be taken to ensure that the amine level remains at least at the minimum 13-foot level. Hydrocarbon checks from connections at the 15-foot and 10-foot levels shall be conducted once per shift, and hand gauging shall be conducted on a daily basis until the amine level is restored to at least 13 feet. After the amine being held in the tank has returned to at least 13 feet, hydrocarbon