FINAL REPORT

Air Quality Assessment for Chennai Petroleum Corporation Limited

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AIR QUALITY ASSESSMENT FOR CHENNAI PETROLEUM CORPORATION LIMITED

1.INTRODUCTION

Indian Institute of Technology Madras, Chennai was entrusted by Chennai Petroleum Corporation Limited (CPCL), Manali, Chennai as an external consultant to conduct the Air quality assessment in Emission stacks and Ambient air quality monitoring (AAQM) in the CPCL premises. Currently, there are around 49 emission stacks out of which only 41 stacks were in operation during the period of measurement. There are around 10 ambient air quality monitoring locations in and around the industry for continuous air quality monitoring.

2. BACKGROUND AND PROJECT STATUS

2.1 Processes involved in refining crude oil

The process of oil refining involves a series of steps that includes separation and blending of petroleum products. The five major processes are briefly described below:

• *Separation processes:* These processes involve separating the different fractions/ hydrocarbon compounds that make up crude oil based on their boiling point differences. Crude oil generally is composed of the entire range of components that make up gasoline, diesel, oils and waxes. Separation is commonly achieved by using atmospheric and vacuum distillation. Additional processing of these fractions is usually needed to produce final products to be sold within the market.

• *Conversion processes:* Cracking, reforming, coking, and visbreaking are conversion processes used to break down large, longer chain molecules into smaller ones by heating or using catalysts. These processes allow refineries to break down the heavier oil fractions into other light fractions to increase the fraction of higher demand components such as gasoline, diesel fuels or whatever may be more useful at the time.

• Treating: Petroleum-treating processes are used to separate the undesirable components and impurities such as sulphur, nitrogen and heavy metals from the products. This involves processes such as hydro-treating, de-asphalting, acid gas removal, desalting, hydro-desulfurization, and sweetening.

• *Blending/combination processes:* Refineries use blending/combination processes to create mixtures with the various petroleum fractions to produce a desired final product. An example of this step would be to combine different mixtures of hydrocarbon chains to produce lubricating oils, asphalt, or gasoline with different octane ratings.

• Auxiliary processes: Refineries also have other processes and units that are vital to operations by providing power, waste treatment and other utility services. Products from these facilities are usually recycled and used in other processes within the refinery and are also important in regards to minimizing water and air pollution. A few of these units are boilers, wastewater treatment, and cooling towers.

2.2 Environmental hazards of petroleum refineries

Refineries are generally considered a major source of pollutants in areas where they are located and are regulated by several environmental laws related to air, land and water. Here is a breakdown of the air, water, and soil hazards posed by refineries:

• *Air pollution hazards:* Petroleum refineries are a major source of hazardous and toxic air pollutants such as BTEX compounds (benzene, toluene, ethyl-benzene, and xylene). They are also a major source of criteria air pollutant: particulate matter (PM), nitrogen oxides (NOx), carbon monoxide (CO), hydrogen sulfide (H2S), and sulfur dioxide (SO2). Refineries also release less toxic hydrocarbons such as natural gas (methane) and other light volatile fuels and oils. Air emissions can come from a number of sources within a petroleum refinery including equipment leaks (from valves or other devices); high-temperature combustion processes in the actual burning of fuels for electricity generation; the heating of steam and process fluids; and the transfer of products. Many thousands of pounds of these pollutants are typically emitted into the environment over the course of a year through normal emissions, fugitive releases, accidental releases, or plant upsets. The combination of volatile hydrocarbons and oxides of nitrogen also contribute to ozone formation, one of the most important air pollution problems in the United States.

• *Water pollution hazards:* Refineries are also potential major contributors to ground water and surface water contamination. Some refineries use deep-injection wells to dispose of wastewater generated inside the plants, and some of these wastes end up in aquifers and groundwater. These wastes are then regulated under the Safe Drinking Water Act (SDWA). Wastewater in refineries may be highly contaminated given the number of sources it can come into contact with during the refinery process (such as equipment leaks and spills and the desalting of crude oil). This contaminated water may be process wastewaters from desalting, water from cooling towers, stormwater, distillation, or cracking. It may contain oil residual sand many other hazardous wastes. This water is recycled through many stages during the refining process and goes through several treatment processes, including a wastewater treatment plant, before being

released into surface waters. The wastes discharged into surface waters are subject to state discharge regulations and are regulated under the Clean Water Act (CWA). These discharge guidelines limit the amounts of sulfides, ammonia, suspended solids and other compounds that may be present in the wastewater. Although these guidelines are in place, sometimes significant contamination from past discharges may remain in surface water bodies.

• *Soil pollution hazards:* Contamination of soils from the refining processes is generally a less significant problem when compared to contamination of air and water. Past production practices may have led to spills on the refinery property that now need to be cleaned up. Natural bacteria that may use the petroleum products as food are often effective at cleaning up petroleum spills and leaks compared to many other pollutants. Many residuals are produced during the refining processes, and some of them are recycled through other stages in the process. Other residuals are collected and disposed of in landfills, or they may be recovered by other facilities. Soil contamination including some hazardous wastes, spent catalysts or coke dust, tank bottoms, and sludge from the treatment processes can occur from leaks as well as accidents or spills on or off site during the transport process.

2.3 Chennai Petroleum Corporation Limited

Chennai Petroleum Corporation Limited (CPCL) are one of the leading group companies of Indian Oil's refineries was started in 1960 with a designed capacity of 2.5 million metric tons per annum (MMTPA) to produce fuels and lubes base stock. It is a joint venture with the National Iranian Oil Company (NIOC), Amoco of USA and Government of India. With their shares such as 53.75% with Govt. of India, 12.21 % with NIOC and remaining 34.04% with FII/Public and other entities. Their production is carried out through two refineries with Refinery I commissioned in the year 1969 with an initial capacity of 2.5 MMTPA of imported crude. After a few years of operation in Refinery I, the production capacity was raised from 2.5 to 2.8 MMTPA with in-house debottlenecking.

Refinery II was established in the year 1984 to double the capacity to 5.6 MMTPA through addition of expanded facilities with a crude distillation unit and a fluidized catalytic cracker unit. Refinery II were designed to process both the indigenous and imported crude oil varieties. In 2001, the the crude refining capacity of the CPCL is increased to 10.5 MMTPA by the commissioning of the refinery – III at the northern area of the CPCL industrial circumstance. Chennai Petroleum Corporation Limited processes about 10.5 MMTPA of crude oil and manufactures a variety of product to serve consumers directly and indirectly. The products

produced by CPCL met the needs of the nation in the field of Power, Energy, Agriculture and Industry. The list of products manufactured by CPCL with their uses are listed below.

- Liquefied Petroleum Gas (LPG)
- Naphtha - For the manufacture of Fertilizers, Plastics, synthetic fibres and scopes of Other Petro chemicals.
- Motor Gasoline - For automobiles.
- Kerosene Oil - For Rural lighting and cooking.
- ATF - For modern Jet planes.
- High Speed Diesel - For heavy transport vehicles.
- Light Diesel oil - For irrigation Oil engine and pump sets.
- Lubricating oils - For various lubrication purposes.
- Furnace oil - Fuel for Boiler and Factories.
- Asphalt - For Roads.
- Sulphur - For the manufacture of Sulphuric Acid.
- Wax - For the manufacture of Candles / Matches.
- Pet coke - For cement industries

CPCL stands tall among the public-sector refining companies in India, with one of the most complex refineries of its kind in the country, producing an array of value-added petroleum products. It also pioneered key initiatives in several areas such as process optimisation, technology absorption, energy conservation, and city sewage reclamation and environment management. Chennai Petroleum Corporation Limited consists of three major sections namely Refinery 1 & Lube Expansion Block, Refinery 2 and Refinery 3. Overall refinery configuration in CPCL is given in Figure 1.

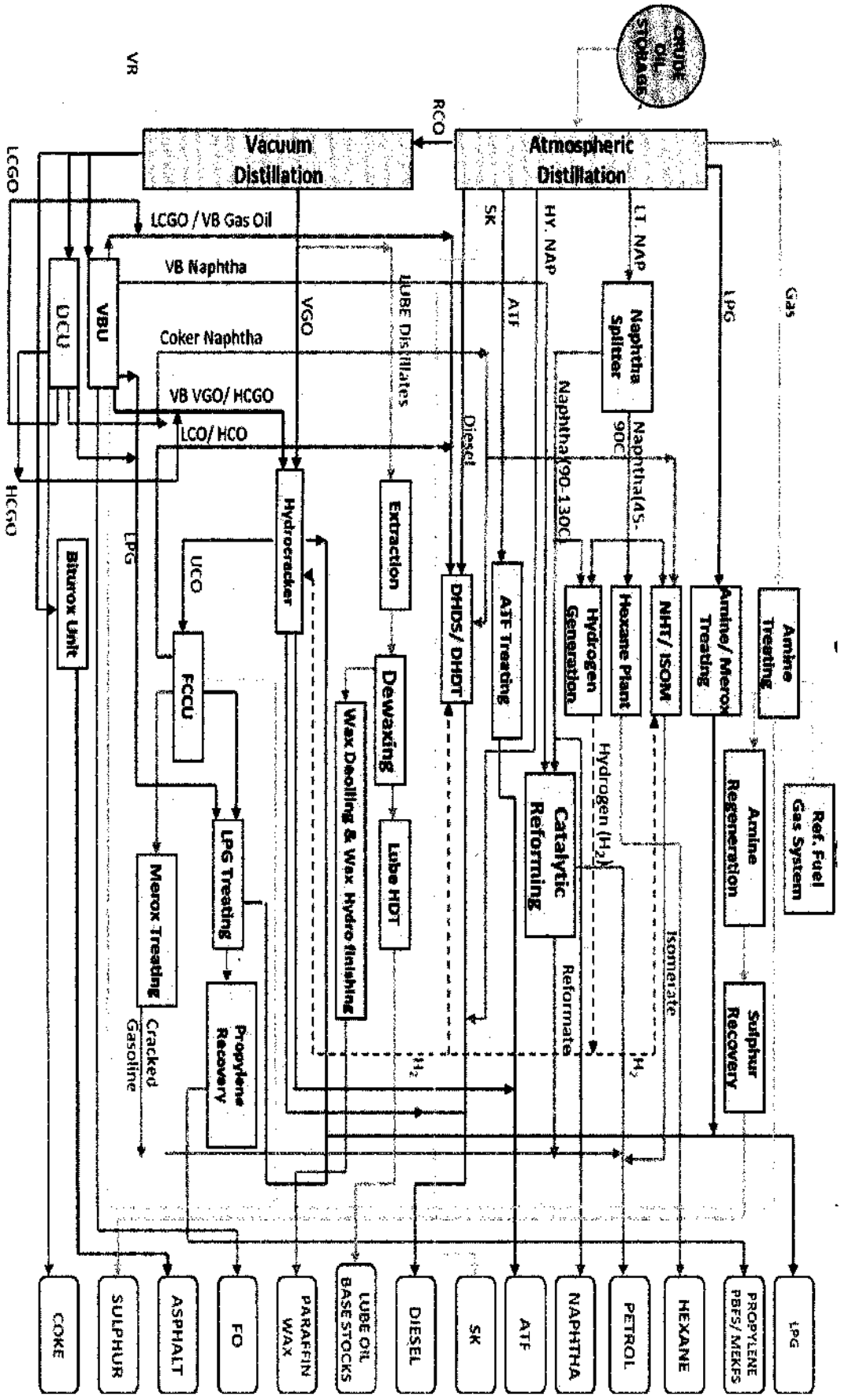


Figure 1 Flow diagram of CPCL Refinery Process

2.3.1 REFINERY I PROCESS

The overall process diagram in refinery I is given in figure 2. Refinery I and Lube expansion block consists of various units which are shown in Table 1.

Table 1 Details of Refinery Units I

Refinery I units:	
Plant 1	Crude Distillation Unit
Plant 2	Vapor Recovery Unit
Plant 4	Kerosene Hydrodesulphurization Unit
Plant 7	Biturox Unit
Plant 9	MEK Dewaxing Unit
Plant 10	Lube oil Hydro finishing Unit
Plant 12	MEA Absorption Unit
Plant 13	Vacuum Distillation Hydrodesulphurization Unit
Plant 89	Delayed Coker Unit
Plant 88	Sour Water Stripper Unit
Plant 89	Amine Regeneration Unit
Plant 90	Sulphur Recovery Unit

Plant 1 CDU/VDU

The crude oil is separated into several fractions all of which required further processing or blending to meet the quality requirements. The separation is effected in atmospheric tower and in two stage vacuum towers. The separation of crude oil into raw products is accomplished in the crude unit by fractional distillation in fractionating columns, based on their distillation range. The process does not involve any chemical changes. The streams obtained are gas, overhead distillate naphtha, heavy naphtha, and kerosene, diesel from atmospheric tower and gas oil, spindle oil, light neutral oil, intermediate neutral and vacuum residuum from second stage vacuum tower.

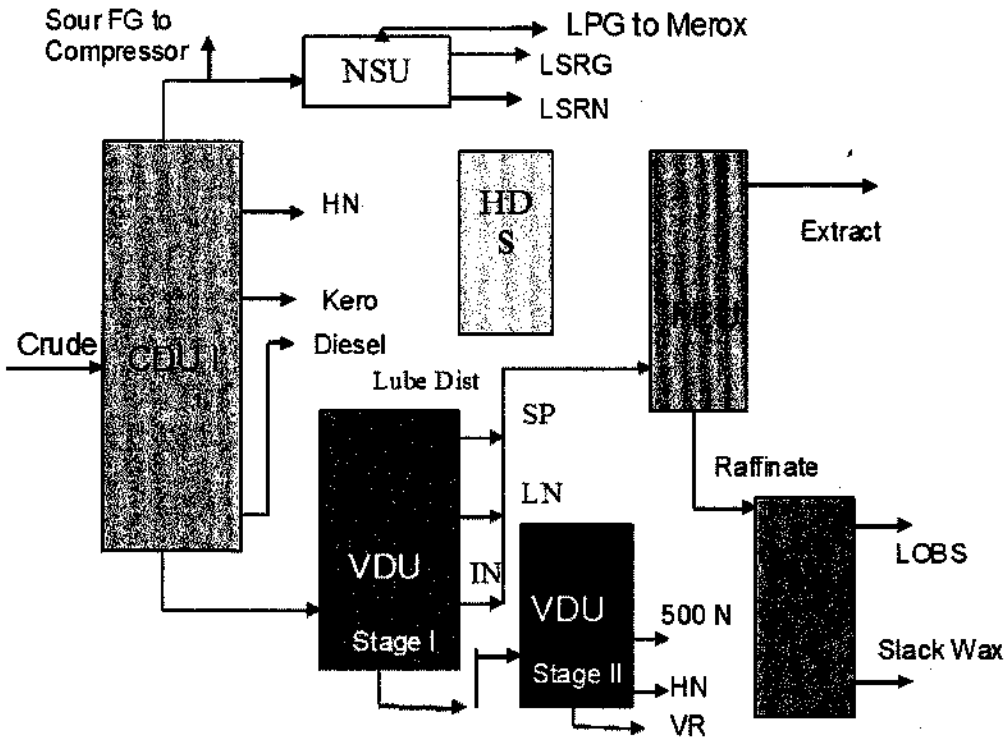


Figure 2 Flow diagram of Refinery I process

Plant 2 Vapour Recovery Unit:

The vapor recovery unit consists of two sections (a) vapor recovery section and (b) merox treating section. The function of vapour recovery section is to separate gas, LPG, light gasoline and light naphtha from the overhead naphtha of atmospheric tower in plant. Merox treating section is for sweetening of LPG, a mixture of light gasoline and light cracked gasoline for gasoline blending, a mixture of light naphtha or heavy naphtha for blending the light gasoline for hexane feed.

Plant 4 Kerosene Hydrodesulphurisation:

The purpose of the plant is to reduce sulphur content of the raw kerosene (ATF / JPs) by treating with hydrogen. During the treatment some of the aromatic hydrocarbons are converted to cycloparaffins, which results in an increase in the smoke point. The plant is designed to process raw kerosene from CDU-I. The hydrogen rich gas from HSDO desulphriser meets the hydrogen requirement and the balance is made up from plant 76 reactor, after heating to the required reaction temperature in the charge heater.

After separation of the reaction gases and excess in a two-stage separator, the effluent is sent to the stripper. The stripper bottom is the finished product sent to storage after cooling. The

hydrogen rich gas from the separator is sent as feed to hydrogen plant or to fuel gas after recovery of the H2S by amine treating in sulphur plant.

Plant 7 Bituroux:

The main function of Biturox Plant is to produce high quality air blown bitumen from the feed stock vacuum residue. This high-quality bitumen (low pen) will be obtained by air blowing the feedstock by means of Oxidation.

Plant 9 MEK Dewaxing Unit:

The function of this unit is to improve the pour point of the feedstock by removing the paraffin's from the feedstock. The unit processes SP HVI / LN HVI / IN HVI / 500N HVI /HN HVI / BN HVI raffinates obtained from NMP extraction unit. The dewaxing is carried out on a blocked-out operation. The dewaxing operation removes enough of heavy paraffins from the feedstock to lower the pour point of this stock. The dewaxing is accomplished by mixing the waxy charge with a solvent consisting of equal proportions of Methyl Ethyl Ketone (MEK) and Toluene, chilling the mixture to precipitate the wax and then filtering the resultant slurry to separate the wax.

Plant 10 Lube Hydro finishing Unit:

The lube oil hydrofinisher employs a hydrogenation process to improve colour stability and lengthen the oxidation period of the finished lube stocks. The hydrogenation reduces sulphur, oxygen, nitrogen and undesirable carbon forming compounds without damaging the other properties of the lube oils. The plant is designed to process all the lube oil stocks from MEK unit. Flash point and odour specification are also attained in the process and Deasphalted Oil on a blocked-out operation.

Plant 12 MEA Gas Treating Unit:

This unit treats the sour gases from all the hydro-desulphurisation units as well as the gases from the vapour recovery plant and separates the H2S and sent it to sulphur recovery unit for producing sulphur. The unit has got two absorbers operating at two different pressures.

Plant 13 Vacuum Distillate Hydro Desulphurisation Unit:

The objective of this unit is to desulphurise straight run diesel from 1.6% weight to 50 ppm. Desulphurisation is achieved through a reactor which consists of 3 beds

Plant 86 Delayed Coking Unit:

The delayed Coker is designed to process residue oils formed in refinery's upstream units. The following are the products from Delayed Coker Unit

- Sweetened fuel gas

- Sweetened LPG
- Light Coker naphtha
- Heavy Coker naphtha
- Light Coker gas oil
- Heavy Coker gas oil
- Petroleum Coke

The Delayed Coker Unit is designed to process 2.2 million metric tonnes per annum of mixed feeds consisting of straight run vacuum residue, PDA pitch, lube extracts and clarified oil. Delayed coking is a thermal cracking process for upgrading heavy petroleum residues into gaseous, liquid and solid products. The petroleum residue is heated in a specially designed heater to high temperature with brief residence time. The thermal cracking reactions start in heater and end in coker drums. The thermal cracking reactions are controlled carefully to minimize coke formation in heater coils. The solid coke is retained in coke drums. Coke drum effluent vapor is quenched to arrest further cracking reactions and then fractioned into various distillate and light end products.

Plant 88 Sour Water Stripper Unit:

The Sour Water Stripper Unit has been designed for removal of Hydrogen Sulphide & ammonia from 59.55 TPH of sour water streams from Delayed Coker Unit & Once through Hydrocracker OHCU Revamp. The feed stream shall contain H_2S, NH_3, H/C, CO_2, cyanides, phenol, etc.

Plant 89 Amine Regeneration Unit (Coker LPG Treatment Unit):

The Coker LPG Treatment Unit has been designed for processing 8800 kg/hr of sweetened LPG from Amine Treatment Unit (as part of DCU) of Resin Upgradation Project using CFC (Continuous Film Contactor) technology. The feed stream shall contain mercaptans, H_2S, HC, CS2, COS, etc. The treated LPG, free from H_2S and, mercaptans.

Plant 90 Sulphur Recovery Unit:

The Sulphur Recovery Unit has been designed with a capacity of 2 X 100 TPD of Sulphur production. The unit will be able to treat acid gas from Amine Regeneration unit (ARU Acid Gas) and Sour Water Stripper unit (SWS HP Stage Acid gas and SWS LP Stage Acid gas) and recover 99.9% of Sulphur contained in the feeds will be routed to storage.

2.3.2 REFINERY II PROCESS

The overall process diagram in refinery II is given in figure 3.

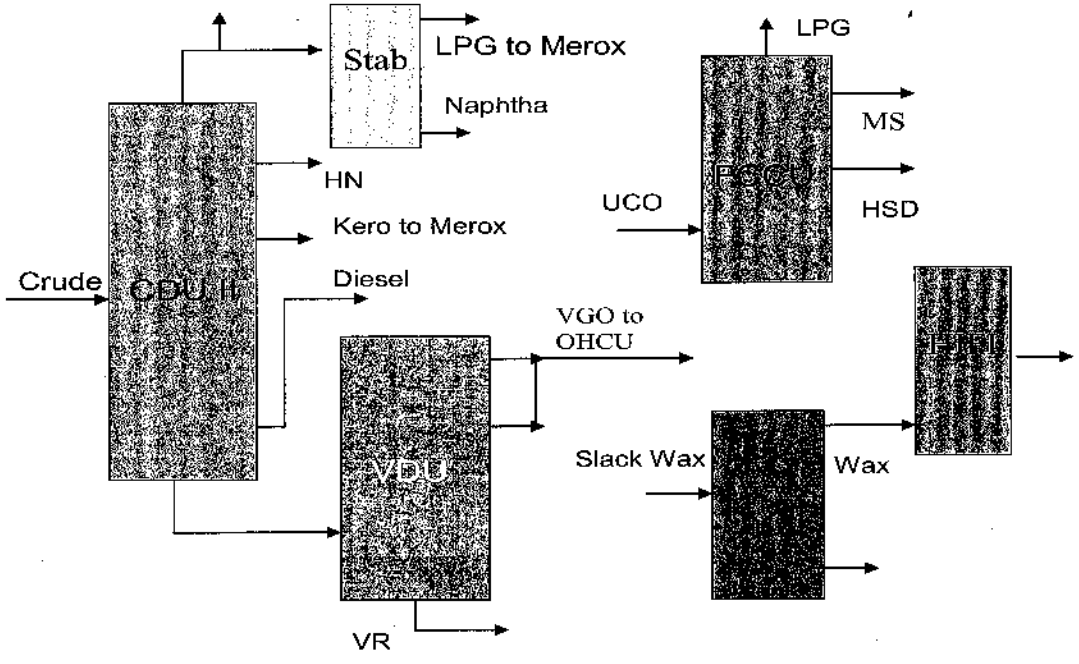


Figure 3 Flow diagram of Refinery II process

Plant 15 Crude Distillation Unit I:

Atmospheric section:

Crude oil stored in offsite crude oil storage tanks is pumped to the atmospheric section. The crude oil is first heated by a set of desalter preheat exchangers to 120-130^{O}C and then sent to desalters. The salt and water are separated out in desalters. The desalted crude is pumped and is preheated to a temperature of 260 - 270°C. It is passed through the coils of crude furnaces where it is partially vaporized and allowed to flash in the atmospheric distillation column. Stripping steam is introduced at the bottom of the distillation column to strip out lighter ends from the un-vapourised portion of the crude. This also helps in vaporisation of crude by lowering of partial pressure. Stripped vapours and vapourised fractions of crude rise through the upper sections of the column and are separated into an overhead and three side draw products. Gas and naphtha obtained, as overhead vapours are totally condensed. The condensed liquid is partly used as top reflux to control the top temperature and the balance flows as feed to Stabiliser section.

Heavy naphtha, kerosene and diesel products are withdrawn as side products and further steam stripped in individual strippers to remove light ends and improve flash of products. Heavy naphtha after cooling is blended with diesel; Kerosene and diesel after cooling routed to storage. Bottom, Middle and Top pump arounds are withdrawn from different trays, cooled and returned to the column to remove the heat and maintain the desired temperature profile in the column. The overhead product from the atmospheric column reflux drum is preheated by exchangers and fed to naphtha Stabilizer. The overhead vapor from this column is partly condensed. The uncondensed gases are sent to fuel gas system. The condensed liquid (LPG) after partly being used as top reflux for the Stabilizer, is sent to Amine /Merox treating unit. The bottom product, stabilized naphtha, from the naphtha Stabilizer is cooled and sent to storage tank.

Vacuum section:

Hot reduced crude oil from atmospheric column is further heated in vacuum furnaces and introduced into the flash zone of the vacuum column. The un-vapourised portion of the feed drops into the bottom section of the tower and is withdrawn as Vacuum residue. The vapourised portion rises up the tower and is fractioned into three side products. Slop distillate (530-550 °C) is withdrawn as the first side product. A part of it is routed to the inlet of vacuum furnace. The balance of slop distillate cut is routed to refinery fuel oil. This slop cut helps in achieving the quality of FCCU feed. Vapours rising from the wash zone passes through a demister pad to ensure

the removal of entrained Asphaltenes. The hydrocarbon vapours get condensed in HVGO and LVGO sections by circulating reflux and internal reflux to the wash zone. LVGO is further fractionated in the intermediate-fractionating zone between LVGO and HVGO sections. LVGO is routed to diesel after cooling. HVGO is supplied to OHCU as hot feed and/or routed to storage after cooling. Vacuum in the column is maintained by a three-stage ejector system, each having three different capacity ejectors. The non-condensable and condensable vapours pass through the inter condenser, the non-condensable vapours are ejected by the 2nd stage ejector into where non-condensable vapours are ejected by 3rd stage ejectors. All condensed liquid from the condensers goes to hot well through barometric leg. The non-condensable from the last condenser bubbling through liquid seal in the hot well to prevent ingress of air and vented out to atmosphere through flame arrester. There is a provision to recycle non-condensable back to 1st stage suction to maintain the desired vacuum. Small amount of oil collection in the Hot well is pumped to slop /upgraded as HSD in Plant 5. The water is pumped to Sour water system. The HVGO and vacuum residue being high pour material are cooled by dedicated Tempered water system before going to storage tanks.

Plant 16 FCCU

The existing FCC Unit was originally designed to process vacuum gas oil feed. A revamp of FCC unit was carried out to process Unconverted oil from OHCU, to meet product specification. The unit consists of feed Section, Main fractionator, R-R section, Main fractionator bottom section and gas concentration units. A major portion of the unit is retained with minor modifications. However, new equipment's have been added as part of the revamp. The second WGC and gas concentration unit are added to handle the additional LPG load. Apart from VGO from CDU / VDU, hot unconverted oil from HCU and VR from CDU / VDU join as feed. Riser naphtha (VB naphtha or DHDS naphtha) is routed directly to the bottom of reactor riser and used as lift gas. The heated fresh feed enters the furnace after preheating and further heating is done to desired temperature as dictated by the heat balance of reactor system. The feed is contacted with a controlled amount of regenerated catalyst and lift steam in the reactor riser. The catalyst flow is controlled to maintain a desired reactor temperature. The hot regenerated catalyst vaporizes the feed and the resultant vapor carry the catalyst upward with minimum back mixing. Cracking occurs as the HC vapours and catalyst travel up the riser. At the top the desired cracking reactions have been completed and the catalyst is separated quickly from HC to minimize further cracking.

The vapours are led to main column followed by gas concentration unit where they are condensed and fractionated into various products viz. Off gas, cracked LPG, cracked Gasoline, LCO, HCO and CLO. As part of improving the reliability of the unit, yield pattern and unit throughput the following modifications were carried out subsequent to revamp:

- Installation of new net liquid pumps
- Installation of additional reboiler for Debutaniser I
- Installation of automatic additive loader system
- Installation of new Main column bottoms pumps
- Installation of two new additional air compressors.

Plant 17 Merox Treating Unit

The MEROX (Mercaptan Oxidation) process is for the chemical treatment of petroleum distillates to remove mercaptans or to convert mercaptans to disulphides. The former is known as extraction where reduction in sulphur content takes place and the latter is known as 'sweetening' where there is no such reduction in sulphur content. Mercaptans impart obnoxious odour, corrosiveness and make the product Doctor positive and are not desirable for sales. Under proper operating conditions and depending on the results desired, distillates up to kerosene range can be successfully treated.

Plant 18 FCCU off Gases- Saturated and Cracked LPG Amine Gas Treater

Hydrogen sulphide (H_2S) and carbon-di-oxide (CO_2) present in hydrocarbon streams are collectively termed as sour gases or acid gases. Such sour gases have to be removed from hydrocarbon streams in order to meet either specifications or to meet downstream processing unit's requirements. H_2S and CO_2 readily combine with aqueous solutions of aliphatic amines at temperatures usually close to ambient and may be driven off from the rich solutions by heating. MEA has higher absorptive power for H_2S and CO_2/Volume of treating solution but has the disadvantage of that any carbonyl sulphide [COS] present in gas (most likely in FCC sour gases) combines irreversibly with it. Hence DEA is used.

Plant 19 Propylene Recovery Unit

The purpose of the unit is to recover Propylene from Cracked LPG. Cracked LPG, one of the products of FCCU is basically a mixture of Propane, Propylene, Butane and Butylene. This Unit first separates the stream into Propane-Propylene and Butane-Butylene mixture in the first

column and then further separates the stream into Propane and Propylene in the second column. The aim is to make Chemical grade Propylene of 95% purity

2.3.3 REFINERY III Process

Refinery III CDU is designed to process 100% Arab mix and 100% Bombay High Crude at the rate of 3 MMTPA. The production process flow diagram for refinery III is given in figure 4. Refinery III CDU was originally designed to process 100% Arab mix and 100% Bombay High Crude at the rate of 3 MMTPA. Major expansion was carried out to process 4.0 MMTPA of Crude with the inclusion of BS IV facilities viz Diesel Hydro-Treating DHDT, a New Naptha Hydro Treating unit, Isomerization unit, a New Hydrogen Generation unit & a new Sour Water Stripper.

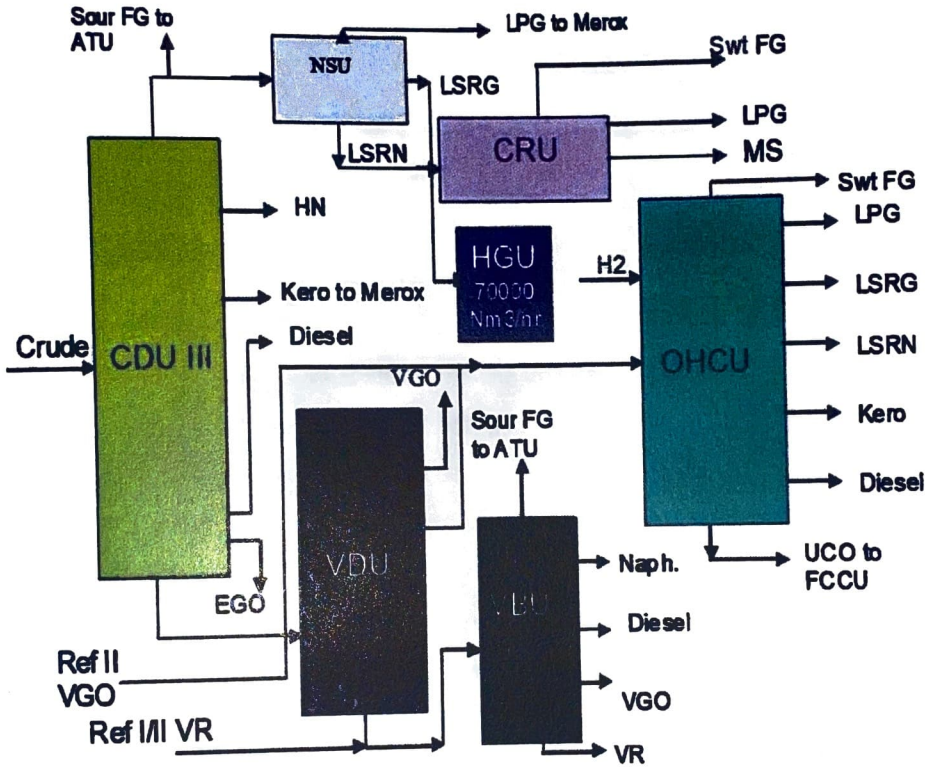


Figure 4 Flow diagram of Refinery III process

Plant 201 Crude Distillation Unit:

Crude is pumped from offsite storage to the CDU/VDU plants to single stage electrostatic desalter provided for removal of salt and water from crude to desired level. Crude from desalter

is routed to atmospheric heater through two parallel heat exchange trains. The preheated crude is fed to atmospheric heater and the partially vaporized crude enters the atmospheric column. Heavy naphtha is drawn from the atmospheric column as a side stream. The light ends of heavy naphtha are knocked off by a reboiler using stripping steam. Lighter HC vapor from side strippers is routed back to crude column. Kerosene products go to kero stripper. Gas oil products is sent to gas oil stripper and EGO product is sent to the EGO stripper.

Heavy naphtha product is cooled and routed to diesel blending. Kero product is routed to the two following destinations - Kero Merox Treater and Diesel Blending in OSBL / DHDS feed tanks. Reduced crude oil (Atmospheric column residue) is pumped to Vacuum Unit.

Naphtha stabilizer heats the unstabilized naphtha consisting of all the fuel gas, LPG and naphtha. LPG from the column is routed to LPG Amine Absorption unit.

CDU III – Revamped:

The Crude and Vacuum Distillation Unit (CDU/VDU) of Refinery-III with a design capacity of 3.0 MMTPA was commissioned in February 2004. The unit was designed by M/s Engineers India Limited (EIL). In line with corporate growth strategy and to meet the growing demand of petroleum products, CPCL has completed revamp of CDU/VDU in Refinery-III to increase its capacity from 3.0 MMTPA to 4.0 MMTPA.

CPCL has revamped the existing Amine Treating Unit and to install a new caustic wash unit (Continuous Film Contactor Process) for treating the incremental LPG Producing besides adding few equipment namely Pre-flash drum, a new two-stage desalter and stabiliser, a new stripper, new Exchangers/Pumps, replacing the existing trays/packings by high capacity trays /packing in Atmospheric Column / Vacuum Column respectively and also envisaging certain heater modifications in Atmospheric Heater/Vacuum Heater etc in CDU/VDU of Refinery-III.

The process units and other associated facilities for the above-mentioned project are located in the existing Manali Refinery Complex. With the establishment of Refinery III CDU/VDU expansion, the installed refining capacity of Manali Refinery has become 10.5 MMTPA.

Vacuum Distillation Unit:

Hot RCO from atmospheric column bottom gets preheated and the partially vaporized RCO enters the vacuum column at the flash zone. The heavy hydrocarbons are stripped by superheated LP steam. The various streams drawn from vacuum column are vacuum diesel, LVGO, HVGO and slop distillate. Vacuum residue with quench is drawn from the bottom.

The overhead circuit consists of 3 stage steam jet ejectors. The vent gases are bubbled through caustic solution before venting in order to scrub hydrogen sulfide.

Hot well slop oil from Hot well is pumped to cold gas oil product line. Vacuum diesel product is sent for blending with gas oil. LVGO and HVGO named as VGO is routed to OHCU partly as hot feed and partly to feed storage.

Plant 202 & 203 LPG Merox & Kero Units:

The LPG Merox unit is targeted to bring down the H2S and mercaptan sulpur to less than 1 ppm and 5 ppm respectively. Straight run (SR) SR Kero merox is to reduce mercaptans to less than 10ppm.Kerosene Merox is steam stripped and sent to water coalescer and caustic prewash before entering merox reactor. Treated kerosene passes through caustic settler batch water wash, salt and clay filter and to storage.

Plant 204 Soaker Visbreaker:

The visbreaker unit is designed to process 85% vacuum residue and 15% propane deasphalted pitch. The individual feeds are mixed and heated to 440°C in the feed heater before entering the soaker. The thermal cracking reactions lead to reduction in viscosity and pour point and generate large amount of gas, cracked gas oil and heavy distillate. The soaker effluent enters the flash zone of visbreaker fractionator where gas, naphtha and gas oil are separated from the residue. Fractionator separates gas oil and naphtha. The fractionator overhead product is unstabilized naphtha which goes to stabilizer section. The remaining vapors, the unstabilized naphtha and sour water are separated in and sour water is sent to the overhead product drum. Unstabilized naphtha in the naphtha stabilizer column separates the light hydrocarbons and the stabilized naphtha from the bottom, which is routed to storage via cooler. The residue from the fractionator enters vacuum flasher in the flash zone for separating the liquid and vapor fractions.

Plant 205 Hydrogen Generation Unit:

Naphtha is pre-desulphurised in the Desulphurisation reactor, containing Co-Mo catalyst, where all sulphur compounds are converted into H2S. The resulting H_2S is stripped out in a H_2S stripper to get sweet naphtha. This sweet naptha is then vaporized and the gas mixture then passes over the ZnO and chlorigaurd catalyst, which absorbs the H_2S and chlorides as these are poisons for the reforming catalyst.

The reforming reaction uses steam and naphtha to produce syn gas containing mainly hydrogen along with small quantities of CO, CO_2 and methane. The impurities of the process gas are removed in a PSA unit. Here the hydrogen is recovered from the process gas (syn gas) by

adsorption of methane, CO, CO2 and water vapor through molecular sieves and active carbon-based adsorbents. Off gas available at low pressure from PSA unit is used as fuel for the reformer. Gas leaving the adsorber is the hydrogen product. The purity of hydrogen is more than 99.5 percent. A small portion of the hydrogen is compressed in the recycle hydrogen compressor and mixed with the feed.

Plant 206 Naphtha Hydro Treatment & Reforming Unit:

NHT is intended for the removal of impurities – (sulphur and metals) that can affect the catalysis in the reforming and isomerization. The treatment is achieved by passing naphtha over fixed bimetallic catalyst bed in an adiabatic reactor in presence of hydrogen.

Reforming Unit:

Naphtha feed to catalytic reforming is to produce high octane aromatics from naphthenes and paraffins for use of high-octane gasoline blending component. H_2 is also one of the important by-products of reforming. Paraffins require severe conditions for conversions while naphthenes do not. Bimetallic catalyst bed in three adiabatic reactors does the process of conversion. The process involves Reactor Section, recontacting section, stabilizing section and De-ethenizer section.

Sour Water Stripper:

A single stage water stripper treats the water generated in CDU/VDU, VBU, HGU and intermittent sour condensate from SRU and flare KOD to strip out H2S in effluent to less than 50 ppm. A two-stage sour water stripper is designed for HCU, NHTU/CRU, ARU to strip out H2S and NH3 in effluent to less than 50 ppm.

Amine Treating Unit:

Fuel Gas Amine Treatment Unit is for absorbing hydrogen sulfide from sour fuel gas streams coming from NHTU, VBU, HGU, HCU and CDU/VDU using DEA as absorbing medium. The rich amine is regenerated in ARU.

Plant 210 Sulfur Recovery Unit:

Sulfur Recovery Plant (SRU) employs the Maximum Claus Recovery Concept (MCRC) technology wherein the Claus process extended up to the temperature at which sulfur starts condensing on the catalyst itself. The plant consists of one thermal reaction section (Main combustion chamber) and four catalytic converters. The first one is the catalytic converter and the other three are MCRC converters that alternate between subdue point mode and regeneration mode. Sulphur

is condensed at different stages to liquid and routed to Sulphur pit. The liquid Sulphur is then sent to pelletising unit

Once Through Hydrocracker:

The design capacity of the Hydrocracker unit is 1.65 MMTPA. The unit is designed to process Vacuum Gas oils from Refinery III and Refinery II, Visbreaker, Vacuum Gas oil and excess vacuum distillates from Refinery I. Feed from various sources are preheated, filtered and routed to the feed surge drum. The feed is then pumped via the reactor effluent exchanger and furnace to the reactors. Recycle hydrogen is introduced upstream of the reactor effluent exchangers. The various reactions that take place in the reactors include de-metallization, hydrotreating and hydrocracking in the presence of various catalysts.

The effluent from the reactors is separated into various products in the fractionation and light end recovery sections. The major products from the unit include LPG, naphtha, ATF/ kerosene and diesel. The bottoms (unconverted oil) are routed as feed to the FCCU.

Plant 208 Sour Water Stripper:

A single stage water stripper treats the water generated in CDU/VDU, VBU, HGU and intermittent sour condensate from SRU and flare KOD to strip out H2S in effluent to less than 50 ppm. A two-stage sour water stripper is designed for HCU, NHTU/CRU, ARU to strip out H_2S and NH_3 in effluent to less than 50 ppm.

Plant 209 Amine Treating Unit:

Fuel Gas Amine Treatment Unit is for absorbing hydrogen sulfide from sour fuel gas streams coming from NHTU, VBU, HGU, HCU and CDU/VDU using DEA as absorbing medium. The rich amine is regenerated in ARU.

Plant 211 Diesel Hydrotreating (DHDT) Unit:

The Diesel Hydrotreating (DHDT) unit will reduce the sulfur content of the diesel streams in the refinery. The unit will process various high sulfur streams like straight run diesel, kerosene, Visbreaker/Delayed Coker gas oils and reduce the sulfur content to < 50 ppm to enable CPCL to meet the Euro IV specifications of diesel.

The various feed streams are combined, mixed with hydrogen and heated to the reaction temperature in the preheat exchangers and furnace. The de-sulfurization reactions take place in the reactor in the presence of a catalyst. Quench is added between the catalyst beds to control the reaction temperature. The effluent from the reactor is cooled and recycle gas is separated

to be sent back to the reaction section. The gas, naphtha and diesel are separated in the downstream section and routed to the respective product destinations.

Plant 212 NHT / ISOM Unit:

The Naphtha Hydrotreating and Isomerisation unit converts Light Coker Naphtha and Straight Run Naphtha into High Octane MS Component. The purpose of the NHT unit is to eliminate the impurities, mainly Sulphur and Nitrogen, which would affect the performance and the life of the Isomerization catalyst. Moreover, for the present project, the feed to the Hydrotreating and Isomerization units is olefins/diolefins rich feed and consequently, hydrogenation of these components will be carried out in a hydrotreating reactor in the presence of catalysts. The Hydrotreated feed is then fed to the Isomerisation section where the Naphtha undergoes Isomerisation reaction in the two Isomerisation reactors A/B. The Isomerate is then fed into stabilizer. The off gas liberated in the stabilizer overhead is sent to a caustic scrubber to neutralize the HC1 contained in the gas and the stabilizer bottoms (raw Isomerate) enter the DIH (De-isohexanizer) column where lighter Isomerate cuts would be produced, and the bottom concentrated in C7 + and C6 Naphthenes is used as lean oil make-up in the LPG recovery section. The purpose of LPG Recovery section is to optimize LPG recovery from the Isomerization unit stabilizer off gas. For this purpose, a part of DIH bottoms stream is used as lean oil. The DIH bottoms stream after being used as lean oil in the LPG recovery section is mixed with the DIH distillate. The resulting combined stream corresponding to the final isomerate product is sent to the battery limit. The liquid effluents generated from the units include sour water, oily water and spent caustic. The estimated liquid effluent is about 1.5 m^3/hr.

Plant 214 DHDT-Hydrogen Generation Unit:

Hydrogen is produced by steam reforming of naphtha, to meet refinery requirements. Naphtha is first desulphurised over a desulphurisation catalyst where in the presence of hydrogen, non-reactive sulphur compounds are hydrogenated to hydrogen sulphide which is then absorbed on zinc oxide beds. The desulphurised feed is mixed with pre heated steam, heated to the desired temperature, and passed into steam reforming furnace tubes containing a nickel-based catalyst. Hydrogen is purified to remove inert gas impurities like carbon dioxide, carbon monoxide, methane, nitrogen, and water vapour by high pressure absorption of these impurities on molecular sieves, activated carbon and alumina gel in Pressure Swing Absorption (PSA) system. All absorbed gases are removed during desorption and regeneration of the beds (purge gas) and used as reformer fuel.

LUBE EXPANSION BLOCK LEB – DHDS

The overall process diagram in refinery I is given in figure 5. Lube expansion block with DHDS consists of various units which are shown in Table 2.

Table 2 Lube expansion block and DHDS Units

Lube Expansion Block units:	
Plant 71	Propane Deasphalting Unit
Plant 72	Propane Recovery Plant
Plant 73	NMP Extraction Unit
Plant 74	Food Grade Hexane Unit
DHDS Units:	
Plant 76	DHDS Hydrogen Unit
Plant 77	Diesel Hydro Desulphurization Unit
Plant 78	Sulphur Recovery Unit
Plant 79	Amine Regeneration Unit
Plant 80	Sour Water Stripping Unit

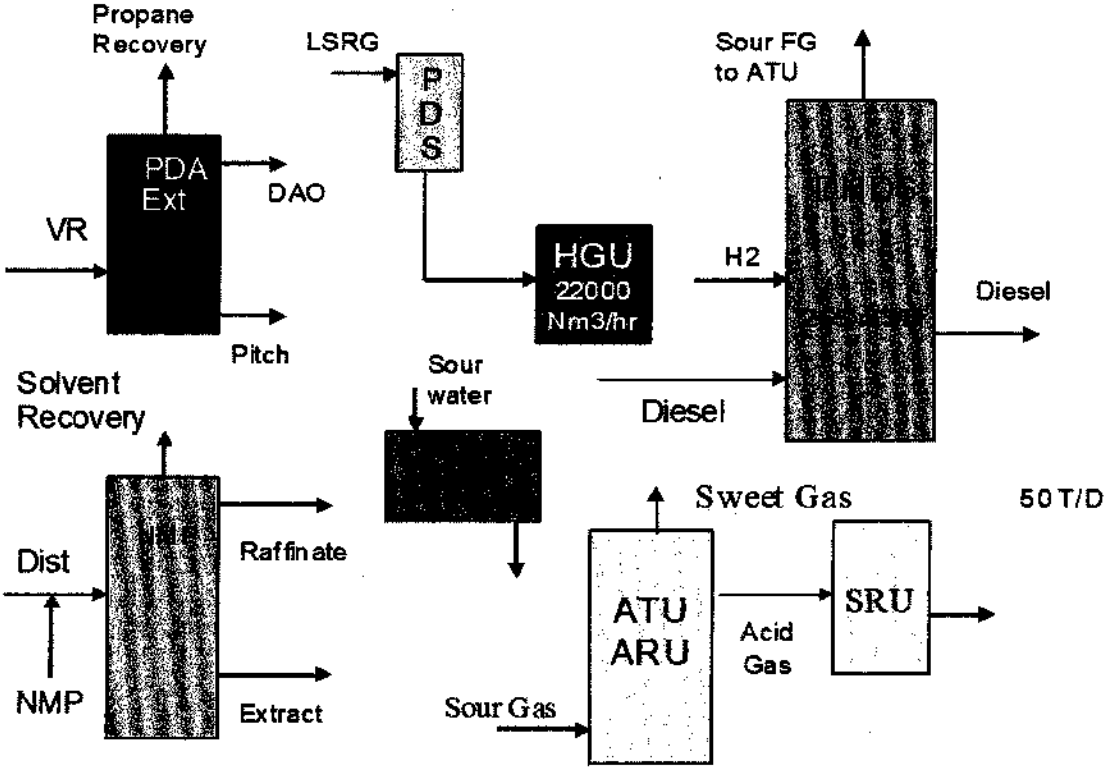


Figure 5 Flow diagram of Lube expansion and DHDS process

Plant 71 Propane Deasphalting Unit:

Propane desphalting unit separates the asphaltic and resinous compounds from an oil fraction by a liquid-liquid extraction of residues from vacuum distillation unit. Liquid propane from plant 72 is used as selective solvent here.

Plant 72 Propane Recovery Unit:

SRLPG is taken to an accumulator, from where it undergoes simple distillation through deproponiser and deethaniser to produce propane.

Plant 73 NMP Extraction Unit:

NMP extraction unit (plant 73) functions for the removal of low-viscosity index hydrocarbons as well as some intermediate lube quality hydrocarbons. This unit has sections like extraction, raffinate recovery, extract recovery and solvent recovery

Plant 74 Hexane:

Food grade hexane plant (plant 74) is designed to produce hexane from light straight run Gasoline in two sections viz., feed naphtha splitting and raw hexane dearomatization.

Plant 76 (DHDS Hydrogen Unit):

The unit was designed to supply the makeup hydrogen required for the diesel hydro desulphurisation plant. The design capacity of the unit is 22500 Nm^3/hr of hydrogen (99.9 Vol. %) based on Naphtha feed. The turn down for the hydrogen plant is 35% of the design capacity - 7875 Nm^3/hr of hydrogen.

Plant 77 Diesel Hydro Desulphurisation:

Unit design capacity was revamped from 180000 MTPA to 234000 in 2017.The function of the High-Speed Diesel Hydro Desulphurisation (DHDS) is to desulphurise by catalytic hydrogenation of the raw diesel to produce a diesel product meeting a 10-ppm max sulphur specification (BS VI).

Plant 78 Sulphur Recovery Unit:

The plant has been designed to convert all sulphur compounds present in the acid gas feed into elemental liquid sulphur. The normal (design) plant capacity is 86.7 MTPD of recovered sulphur. The process design of Sulphur Recovery Unit (SRU) is based on the MCRC (Maximum Claus Recovery Concept) technology which is licensed by M/s. DELTA HUDSON ENGINEERING LIMITED. It is a combination of Claus process and the extension of Claus reaction up to the temperature at which the product sulphur starts condensing on the catalyst itself. Extension of Claus reaction up to sulphur dew point enhances Sulphur recoveries beyond 99%.

Plant 79 Amine Regeneration:

The amine regeneration unit is designed to regenerate rich diethanol amine (DEA) solution containing H2S from DHDS amine absorbers to obtain lean DEA solution for reuse in the different amine absorption columns. In 2008, Diethanol amine (DEA) was replaced by Methyl Diethanol amine (MDEA). Advantage of MDEA include high selectivity for H2S over carbon dioxide, higher energy efficiency, higher resistance to degradation and less corrosivity as compared to DEA.

Plant 80 Sour Water Stripping:

The water stripper unit is designed to treat sour water generated in the DHDS Plant, DHDS hydrogen plant & sour water from flare KOD. The sour water unit has the design capacity to process 11.5 Tones / hour of sour water based on 8000 stream hours. The treated water from the unit will have the H_2S and Ammonia not exceeding 50 ppm by weight. Provision is kept for routing the treated water to either Desalter in the existing crude unit or Refinery effluent treatment plant.

3. FIELD VISITS AND DATA COLLECTION

Prof. S. Mohan and his team from Environmental and Water Resources Engineering division, Department of Civil Engineering, Indian Institute of Technology Madras visited the CPCL unit, Manali on 16th January 2021 for the initial planning for the assessment for air quality monitoring study. Officials from Environmental division, CPCL gave a brief presentation about the industry and its production and requirement for air quality monitoring in emission stacks and ambient air quality locations. IIT Madras has undertaken the monitoring of both emission stacks and ambient air quality monitoring. A total of 41 emission stacks and 10 locations for ambient air quality monitoring were carried out in the CPCL premises. Remaining 8 stacks were not operational during the period of measurement in January- February 2021.

3.1 Ambient air quality monitoring:

To assess the impact of plant operation on the ambient, air quality monitoring was carried out in 10 selected locations of CPCL. The AAQ monitoring should be measured for 2 times in a week for 4 weeks regularly. Monitoring locations were selected based on the predominant wind direction and physical observance of the location through which TNPCB will conduct the air quality monitoring regularly. The 24-hr average concentrations of PM_{10}, $PM_{2.5}$, SO_2, NO_2, O_3, NH_3, Benzene, Benzopyrene, Lead, Arsenic and Nickel were measured. Details of the ambient

monitoring locations are highlighted in Table 3. The ambient air quality monitoring was carried out during January to February 2021.

Table 3 Ambient Air Quality Monitoring Locations

Station	Ambient air quality monitoring location
1	R&D unit
2	CPP (Cogeneration Power Plant)
3	SRU (Sulphur Recovery Unit)
4	Electrical Sub Station - 5
5	Temple (west gate)
6	ETP - 2 (Effluent Treatment Plant - 2)
7	TTP (Tertiary Treatment Plant)
8	Polytechnic Building
9	ISOM (Isomerization unit)
10	Refinery - II

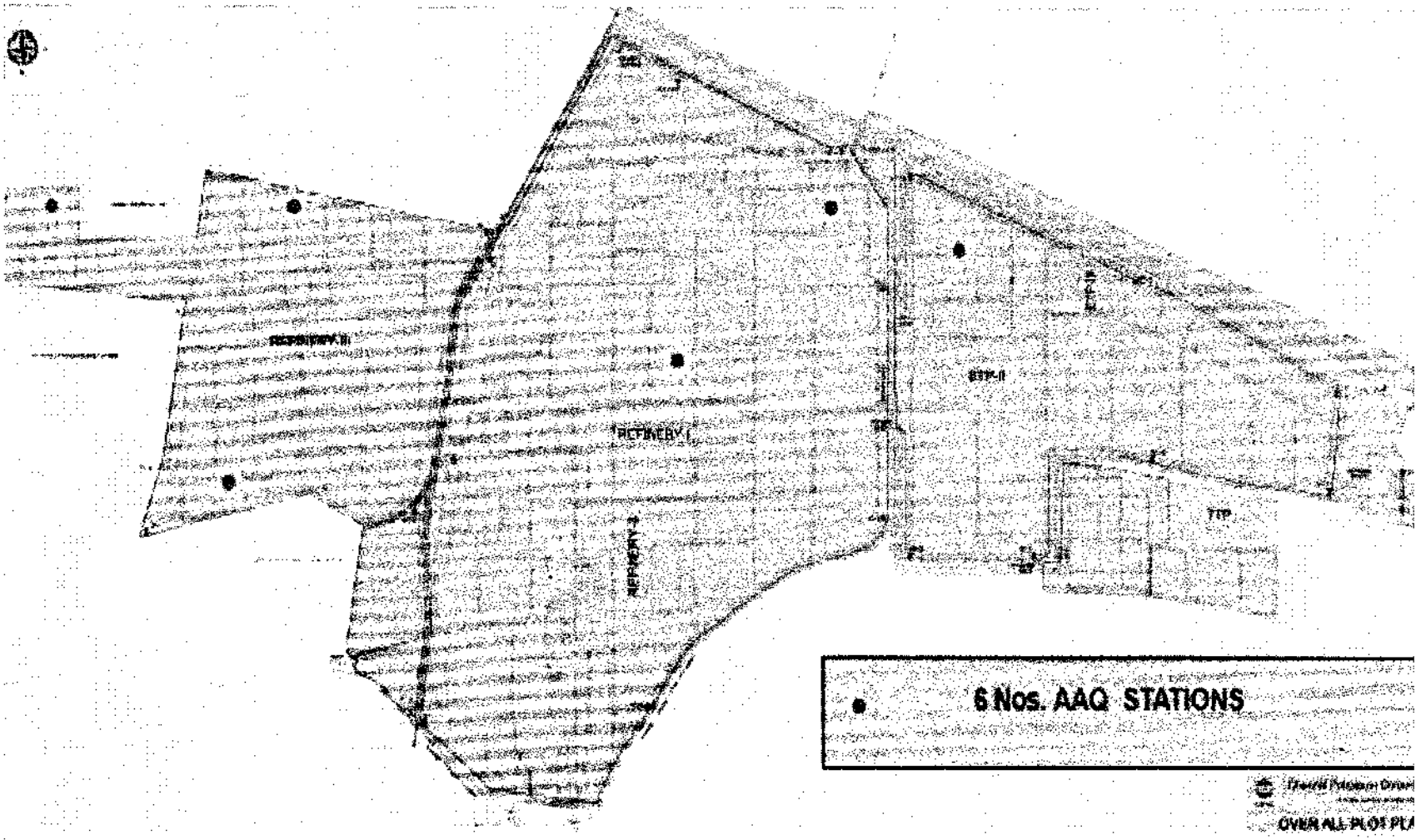


Figure 6 Ambient Air quality monitoring stations

3.1.1 Measurement of ambient PM_{10} and $PM_{2.5}$ concentrations

The 24-hr average PM_{10} mass was collected using a high-volume sampler (HVS), TEI 121 DFM (Thermo Environmental Instruments Pvt. Ltd. India). Glass microfiber filter of size 20.3 x 25.4 cm (Whatman International Limited, USA) was used to collect the PM_{10} mass with an average flow rate of 1.1 m^3 /min. The 24-hr average $PM_{2.5}$ mass was collected using TEI 108 BL (Thermo Environmental Instruments Pvt. Ltd. India) with an average flow rate of 16.7 m^3 /min. Polytetrafluoroethylene (PTFE) membrane filters of diameter 46.2 mm with a pore size of 0.2 µm (Whatman International Limited, USA) were used to collect the $PM_{2.5}$ mass. Filters were placed in aluminium foil sealed cassette while carrying from the field. Filters were weighed twice before and after the sampling to determine the PM_{10} and $PM_{2.5}$ concentrations. Before weighing, the samples were equilibrated in a desiccator at room temperature at a relative humidity of 30-40% for 24 hours. The sampling was carried out as per CPCB, 2011 guidelines.

3.1.2 Measurement of ambient gaseous pollutants (SO_2, NO_2, NH_3)

A gaseous sampling attachment, TEI-110 (Thermo Environmental Instruments Pvt. Ltd, India) was used to collect gaseous pollutants such as SO_2, $NO_2$and NH_3at the flow rate of 1 L min^{-1}. The gaseous sampling was carried out as per CPCB, 2011 protocol. The midget impingers with suitable absorption media were used to collect the samples.

Modified West and Gaeke method (CPCB, 2011) was used for SO_2 analysis. The SO_2 from the air was absorbed in a solution of potassium tetra-chloromercurate (TCM) to form dichloro-sulphito-mercurate complex, the complex formed was made to react with pararosaniline and formaldehyde to form the intensely coloured pararosaniline methyl sulfonic acid. The absorbance of the solution was measured using a UV–visible spectrophotometer at 560 nm.

Modified Jacobs and Hochheiser method (CPCB, 2011) was used for NO_2 analysis. NO_2 was collected by bubbling air through a solution of sodium hydroxide and sodium arsenite. The concentration of nitrite ion (NO_2^-) produced during sampling was determined colorimetrically by reacting the nitrite ion with phosphoric acid, sulphanilamide, and N-(1-naphthyl)-ethylenediamine di-hydrochloride (NEDA) and measuring the absorbance of the highly coloured complex at 540 nm using UV–visible spectrophotometer.

Indophenol method (CPCB, 2011) was used to quantify NH_3 concentration. Ammonia in the atmosphere is collected by bubbling a measured volume of air through a dilute solution of sulphuric acid to form ammonium sulphate. The ammonium sulphate formed was made to react with phenol and alkaline sodium hypochlorite to produce indophenol. The reaction is

accelerated by the addition of Sodium Nitroprusside as a catalyst. The absorbance of the solution was measured using a UV–visible spectrophotometer at 630 nm.

The sampling of ammonia was carried out as per IS 11255 (Part–6):2008 stipulation. Ammonia is collected in dilute sulphuric acid solution in two glass impingers to form ammonium sulphate. The ammonium sulphate formed was made to react with phenol and alkaline sodium hypochlorite to produce indophenol. The reaction is accelerated by the addition of Sodium Nitroprusside as a catalyst. The absorbance of the solution was measured using a UV–visible spectrophotometer at 630 nm. The sampling was carried out for 30 minutes with a flow rate of 2 litres/min. Standard methods for Ambient air quality measurements were shown in Table 4 with their permissible limits as per NAAQS 2009.

Table 4 National Ambient Air Quality Standards 2009

		Concentrations in Ambient Air
Pollutant	Time Weighted Average	Industrial, Residential, Rural & other areas
Sulphur dioxide (SO_2), $\mu g/m^3$	Annual	50
	24 hours	80
Nitrogen dioxide (NO_2), $\mu g/m^3$	Annual	40
	24 hours	80
Particulate Matter PM_{10}, $\mu g/m^3$	Annual	60
	24 hours	100
Particulate matter $PM_{2.5}$, $\mu g/m^3$	Annual	40
	24 hours	60
Ozone (O_3), $\mu g/m^3$	8 hours	100
	1 hour	180
Lead (Pb), $\mu g/m^3$	Annual	0.5
	24 hours	1.0
Carbon monoxide (CO), mg/m^3	8 hours	02
	1 hour	04
Ammonia (NH_3), $\mu g/m^3$	Annual	100
	24 hours	400
Benzene (C_6H_6), $\mu g/m^3$	Annual	05

Benzo(α) Pyrene (BaP) – particulate phase only, ng/m^3	Annual	01
Arsenic (As), ng/m^3	Annual	06
Nickel (Ni), ng/m^3	Annual	20

Ambient air quality measurements were done at ten locations twice a week for four weeks regularly all the Ambient air quality parameter were within the NAAQ standards. Further, the pollutants were analysed NAAQS pollutants for 10 locations in the air quality laboratory and the pollutant concentrations for 10 locations are shown in Tables 5, 6, 7, 8, 9, 10, 11 and 12.

Table 5 Ambient Air Quality Monitoring Results for First Week

S.NO	POLLUTANT	UNIT	R & D		SRU		CPP		Temple		SS-5	
			20th – 21st Jan 2021	21st – 22nd Jan 2021	20th – 21st Jan 2021	21st – 22nd Jan 2021	20th – 21st Jan 2021	21st – 22nd Jan 2021	20th – 21st Jan 2021	21st – 22nd Jan 2021	20th – 21st Jan 2021	21st – 22nd Jan 2021
1	Sulphur Dioxide as SO_2	$\mu g/m^3$	20.17	17.99	26.51	20.28	26.51	22.95	20.97	24.05	17.34	16.47
2	Nitrogen Dioxide as NO_2	$\mu g/m^3$	34.69	32.58	28.39	34.22	35.43	30.03	35.87	33.27	29.84	36.38
3	Particulate Matter (PM_{10})	$\mu g/m^3$	58.1	56.92	51.3	42.42	40	55.82	43.6	48.31	42.13	47.86
4	Particulate Matter ($PM_{2.5}$)	$\mu g/m^3$	24.45	45.62	37.34	27.92	28.46	33.27	27.61	33.58	36.14	34.1
5	Lead as Pb	$\mu g/m^3$	0.01	BLQ	0.008	BLQ	0.009	BLQ	BLQ	0.016	0.008	0.01
6	Ammonia as NH_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
7	Ozone as O_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
8	Carbon Monoxide as CO	mg/m^3	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
9	Benzene	$\mu g/m^3$	4.17	4.18	4.25	BLQ	4.36	BLQ	BLQ	BLQ	BLQ	4.2
10	Benzo(a)Pyrene	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
11	Arsenic as As	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
12	Nickel as Ni	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	2.56	2.17	BLQ

Table 6 Ambient Air Quality Monitoring Results for First Week

S.NO.	POLLUTANT	UNIT	ETP 2		ITP		POLYTECHNIC		ISOMER (CABIN)		REFINERY 2	
			20th – 21st Jan 2021	21st – 22nd Jan 2021	20th – 21st Jan 2021	21st – 22nd Jan 2021	20th – 21st Jan 2021	21st – 22nd Jan 2021	21st – 22nd Jan 2021	22nd – 23rd Jan 2021	21st – 22nd Jan 2021	22nd – 23rd Jan 2021
1	Sulphur Dioxide as SO_2	µg/m³	22.56	13.43	17.48	11.93	23.84	14.55	20.8	15.61	14.13	20.02
2	Nitrogen Dioxide as NO_2	µg/m³	30.44	31.52	28.16	32.32	34.82	31.32	31.31	31.32	28.62	37.43
3	Particulate Matter (PM_{10})	µg/m³	41.83	45.45	45.71	65	51.16	53.28	50.44	48.52	44.24	45.27
4	Particulate Matter ($PM_{2.5}$)	µg/m³	29.15	32.86	28.48	34.72	23.79	28.15	32.79	36.45	32.85	35.22
5	Lead as Pb	µg/m³	0.008	0.016	0.005	0.008	0.008	0.051	0.007	BLQ	BLQ	BLQ
6	Ammonia as NH_3	µg/m³	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
7	Ozone as O_3	µg/m³	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
8	Carbon Monoxide as CO	mg/m³	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
9	Benzene	µg/m³	BLQ	4.38	BLQ	BLQ	BLQ	BLQ	4.21	4.16	BLQ	BLQ
10	Benzo(a)Pyrene	ng/m³	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
11	Arsenic as As	ng/m³	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
12	Nickel as Ni	ng/m³	2.25	2.5	BLQ	2.18	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ

Table 7 Ambient Air Quality Monitoring Results for Second Week

S.NO	POLLUTANT	UNIT	R & D		SRU		CPP		Temple		SS-5	
			25th - 26th Jan 2021	26th - 27th Jan 2021	25th - 26th Jan 2021	26th - 27th Jan 2021	25th - 26th Jan 2021	26th - 27th Jan 2021	25th - 26th Jan 2021	26th - 27th Jan 2021	25th - 26th Jan 2021	26th - 27th Jan 2021
1	Sulphur Dioxide as SO_2	$\mu g/m^3$	26.53	16.41	19.07	20.07	16.41	22.69	22.87	26.49	23.69	27.1
2	Nitrogen Dioxide as NO_2	$\mu g/m^3$	37.61	28.42	34.64	28.04	39.17	30.43	26.33	34.37	25.46	36.78
3	Particulate Matter (PM_{10})	$\mu g/m^3$	67.03	73.08	55	71.01	71.7	84.97	75.99	73.46	70.27	87.85
4	Particulate Matter ($PM_{2.5}$)	$\mu g/m^3$	37.38	37.05	37.22	41.54	43.91	34.02	42.08	33.56	37.47	40.04
5	Lead as Pb	$\mu g/m^3$	0.02	BLQ	0.04	0.007	0.08	0.005	0.009	BLQ	0.007	0.004
6	Ammonia as NH_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
7	Ozone as O_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
8	Carbon Monoxide as CO	mg/m^3	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
9	Benzene	$\mu g/m^3$	4.14	4.77	4.17	4.81	4.21	4.31	4.56	BLQ	4.71	4.11
10	Benzo(a)Pyrene	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
11	Arsenic as As	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
12	Nickel as Ni	ng/m^3	BLQ	BLQ	BLQ	BLQ	2.17	BLQ	2.17	BLQ	BLQ	BLQ

Table 8 Ambient Air Quality Monitoring Results for Second Week

S.NO.	POLLUTANT	UNIT	ETP 2		TTP		POLYTECHNIC		ISOMER (CABIN)		REFINERY 2	
			25th - 26th Jan 2021	26th - 27th Jan 2021	25th - 26th Jan 2021	26th - 27th Jan 2021	25th - 26th Jan 2021	26th - 27th Jan 2021	25th - 26th Jan 2021	26th - 27th Jan 2021	25th - 26th Jan 2021	26th - 27th Jan 2021
1	Sulphur Dioxide as SO_2	$\mu g/m^3$	26.59	18.42	24.61	15.99	22.51	13.78	19.6	19.92	18.06	19.94
2	Nitrogen Dioxide as NO_2	$\mu g/m^3$	29.97	29.58	31.5	29.23	35.76	26.82	33.36	27.54	30.55	28.6
3	Particulate Matter (PM_{10})	$\mu g/m^3$	68.94	77.1	78.51	64.05	76.27	55.94	82.76	53.24	69.33	56.44
4	Particulate Matter ($PM_{2.5}$)	$\mu g/m^3$	42.37	34.68	40.54	19.38	37.55	20.83	36.39	30.31	33.23	32.93
5	Lead as Pb	$\mu g/m^3$	0.008	0.009	0.005	0.004	0.007	BLQ	0.004	BLQ	0.009	0.007
6	Ammonia as NH_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
7	Ozone as O_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
8	Carbon Monoxide as CO	mg/m^3	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
9	Benzene	$\mu g/m^3$	4.92	4.39	4.31	4.11	4.81	4.19	4.81	BLQ	4.81	4.3
10	Benzo(a)Pyrene	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
11	Arsenic as As	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
12	Nickel as Ni	ng/m^3	2.25	BLQ	BLQ	BLQ	2.18	BLQ	BLQ	BLQ	BLQ	BLQ

Table 9 Ambient Air Quality Monitoring Results for Third Week

S.NO	POLLUTANT	UNIT	R & D		SRU		CPP		Temple		SS-5	
			03rd- 04th Feb 2021	04th- 05th Feb 2021	03rd- 04th Feb 2021	04th- 05th Feb 2021	03rd- 04th Feb 2021	04th- 05th Feb 2021	03rd- 04th Feb 2021	04th- 05th Feb 2021	03rd- 04th Feb 2021	04th- 05th Feb 2021
1	Sulphur Dioxide as SO_2	$\mu g/m^3$	17.72	19.08	21.97	17.82	25.79	20.94	30.18	17.73	16.92	16.97
2	Nitrogen Dioxide as NO_2	$\mu g/m^3$	27.32	28.06	32.17	26.83	37.6	28.59	43.33	26.49	29.02	25.58
3	Particulate Matter (PM_{10})	$\mu g/m^3$	50.98	76.39	69.73	74.58	77.71	73.14	68.44	67.22	72.69	70.96
4	Particulate Matter ($PM_{2.5}$)	$\mu g/m^3$	21.79	41.38	30.11	48.99	39.46	44.49	38.8	40.71	27.45	36.72
5	Lead as Pb	$\mu g/m^3$	0.005	0.012	0.007	0.005	0.009	0.012	0.005	BLQ	0.005	0.004
6	Ammonia as NH_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
7	Ozone as O_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
8	Carbon Monoxide as CO	mg/m^3	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
9	Benzene	$\mu g/m^3$	4.19	4.38	4.78	4.08	4.21	4.13	4.35	BLQ	4.89	4.19
10	Benzo(a)Pyrene	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
11	Arsenic as As	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
12	Nickel as Ni	ng/m^3	2.17	2.39	2.48	BLQ	2.48	BLQ	BLQ	BLQ	BLQ	2.15

Table 10 Ambient Air Quality Monitoring Results for Third Week

S.NO	POLLUTANT	UNIT	ETP 2		TTP		POLYTECHNIC		ISOMER (CABIN)		REFINERY 2	
			03rd- 04th Feb 2021	04th- 05th Feb 2021	03rd- 04th Feb 2021	04th- 05th Feb 2021	03rd- 04th Feb 2021	04th- 05th Feb 2021	03rd- 04th Feb 2021	04th- 05th Feb 2021	03rd- 04th Feb 2021	04th- 05th Feb 2021
1	Sulphur Dioxide as SO_2	$\mu g/m^3$	17.54	15.02	25.29	16.48	22.43	15.34	21.87	14.74	20.98	15.62
2	Nitrogen Dioxide as NO_2	$\mu g/m^3$	30.96	26.67	34.39	29.35	31.69	33.45	31.5	35.23	35.59	37.71
3	Particulate Matter (PM_{10})	$\mu g/m^3$	70.31	72.22	72	74.76	69.56	72.53	73.47	76.39	72.45	73.45
4	Particulate Matter ($PM_{2.5}$)	$\mu g/m^3$	30.52	39.3	41.71	42.04	41.08	41.21	40.96	40.71	35.97	34.85
5	Lead as Pb	$\mu g/m^3$	0.006	0.009	0.007	0.011	0.003	0.004	0.01	BLQ	0.004	0.012
6	Ammonia as NH_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
7	Ozone as O_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
8	Carbon Monoxide as CO	mg/m^3	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
9	Benzene	$\mu g/m^3$	4.56	4.49	4.95	4.79	4.49	4.1	4.17	BLQ	BLQ	4.91
10	Benzo(a)Pyrene	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
11	Arsenic as As	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
12	Nickel as Ni	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	2.19	2.41	BLQ	BLQ	2.59

Table 11 Ambient Air Quality Monitoring Results for Fourth Week

S.No	Parameters	Unit	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1	Sulphur Dioxide as SO_2	µg/m³	19.95	18.76	22.9	21.9	27.05	19.36	22.77	20.72	18.7	23.44
2	Nitrogen Dioxide as NO_2	µg/m³	34.26	35.77	24.95	26.71	30.49	22.97	35.6	21.9	26.16	25.79
3	Particulate Matter (PM_{10})	µg/m³	76.16	78.48	68.03	63.16	73.62	70.94	75.72	76.51	74.3	72.92
4	Particulate Matter ($PM_{2.5}$)	µg/m³	36.14	35.43	22.33	30.98	31.02	38.3	33.31	34.51	35.72	36.64
5	Lead as Pb	µg/m³	0.005	0.006	0.006	0.005	0.007	0.006	0.007	0.008	0.008	0.006
6	Ammonia as NH_3	µg/m³	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
7	Ozone as O_3	µg/m³	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
8	Carbon Monoxide as CO	mg/m³	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
9	Benzene	µg/m³	4.13	4.1	4.15	4.6	4.8	4.32	4.9	4.5	4.6	4.7
10	Benzo(a)Pyrene	ng/m³	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
11	Arsenic as As	ng/m³	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
12	Nickel as Ni	ng/m³	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ

Table 12 Ambient Air Quality Monitoring Results for Fourth Week

S.NO	POLLUTANT	UNIT	ETP 2		TTP		POLYTECHNIC		ISOMER (CABIN)		REFINERY 2	
			08th- 09th Feb 2021	09th- 10th Feb 2021	08th- 09th Feb 2021	09th- 10th Feb 2021	08th- 09th Feb 2021	09th- 10th Feb 2021	08th- 09th Feb 2021	09th- 10th Feb 2021	08th- 09th Feb 2021	09th- 10th Feb 2021
1	Sulphur Dioxide as SO_2	$\mu g/m^3$	17.62	17.82	15.33	19.43	21.84	21.98	24.22	25.26	26.81	22.69
2	Nitrogen Dioxide as NO_2	$\mu g/m^3$	25.09	28.91	24.17	32.52	29.18	36.41	31.96	38.48	34.79	30.24
3	Particulate Matter (PM_{10})	$\mu g/m^3$	78.15	70.01	65.71	71.43	70.13	70.45	69.76	65.93	73.98	68.56
4	Particulate Matter ($PM_{2.5}$)	$\mu g/m^3$	27.24	35.55	38.71	39.38	35.8	36.09	31.15	30.98	36.39	28.48
5	Lead as Pb	$\mu g/m^3$	0.006	0.006	0.008	0.008	0.005	0.009	0.007	0.006	0.009	0.007
6	Ammonia as NH_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
7	Ozone as O_3	$\mu g/m^3$	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
8	Carbon Monoxide as CO	mg/m^3	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL	BDL
9	Benzene	$\mu g/m^3$	4.7	4.2	4.8	4.8	4.9	4.8	4.9	4.6	4.6	4.9
10	Benzo(a)Pyrene	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
11	Arsenic as As	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ
12	Nickel as Ni	ng/m^3	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ	BLQ

Table 13 Ambient Air pollutants concentration range for each location

Parameters	NAAQS Limit	R & D	SRU	CPP	Temple	SS-5	Comments
SO_2	80 µg/m^3	16 -27	17 -27	16 – 28	17 - 30	16 – 37	Well within the standard limit
NO_2	80 µg/m^3	27 - 38	24 – 35	22 – 40	21 – 44	25 - 37	Well within the standard limit
PM_{10}	100 µg/m^3	50 – 79	42 – 75	40 – 85	43 – 77	42 – 88	Well within the standard limit
$PM_{2.5}$	60 µg/m^3	21 – 46	22 – 49	28 – 45	27 – 43	27 - 40	Well within the standard limit
Pb	1 µg/m^3	0.005 – 0.02	0.005 – 0.04	0.005 – 0.08	0.005 – 0.016	0.004 – 0.01	Well within the standard limit
NH_3	400 µg/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
O_3	100 µg/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
CO	2 mg/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
Benzene	5 µg/m^3	4.1 – 4.8	4.1 – 4.9	4.1 – 4.8	4.3 – 4.9	4.1 – 4.9	Well within the standard limit
Benzo(a)Pyrene	1 ng/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
As	6 ng/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
Ni	20 ng/m^3	2.1 – 2.4	BDL – 2.4	2.1 - 2.5	2.1 – 2.6	2.1 – 2.2	Well within the standard limit

Table 14 Ambient Air pollutants concentration range for each location

Parameters	NAAQS Limit	ETP 2	TTP	POLYTECHNIC	ISOMER (CABIN)	REFINERY 2	Comments
SO_2	80 µg/m^3	13 -27	11 -26	13 - 24	14 – 26	14 - 27	Well within the standard limit
NO_2	80 µg/m^3	25 - 32	24 - 35	26 – 37	27 – 39	28 – 38	Well within the standard limit
PM_{10}	100 µg/m^3	41 – 79	45 – 79	51 – 77	48 – 83	44 – 74	Well within the standard limit
$PM_{2.5}$	60 µg/m^3	27 – 43	19 – 43	20 – 42	30 – 41	28 – 37	Well within the standard limit
Pb	1 µg/m^3	0.006 – 0.016	0.004 – 0.011	0.003 - 0.051	0.004 – 0.01	0.004 – 0.012	Well within the standard limit
NH_3	400 µg/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
O_3	100 µg/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
CO	2 mg/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
Benzene	5 µg/m^3	4.2 – 4.7	4.1 – 4.8	4.1 – 4.9	4.1 – 4.9	4.1 – 4.9	Well within the standard limit
Benzo(a)Pyrene	1 ng/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
As	6 ng/m^3	BDL	BDL	BDL	BDL	BDL	Well within the standard limit
Ni	20 ng/m^3	2.2 – 2.5	DL – 2.2	2.1 – 2.2	2.4 – 2.6	2.4 – 2.6	Well within the standard limit

Table 15 Ambient air quality Monitoring by TNPCB during March 2019 at CPCL

S. No.	Pollutant	Unit	Concentration	NAAQS Limit
1	SO_2	$\mu g/m^3$	8 - 27	80 (24 hours)
2	NOx	$\mu g/m^3$	9 - 18	80 (24 hours)
3	PM_{10}	$\mu g/m^3$	48 - 86	100 (24 hours)
4	$PM_{2.5}$	$\mu g/m^3$	13 - 39	60 (24 hours)

Table 15 shows the ambient air quality measurements conducted by TNPCB for four pollutants during March 2019. In comparison with our analysed results, it was found that PM_{10} were decreased from 86 $\mu g/m^3$ to 83 $\mu g/m^3$ which is well within the standard limit of 100 $\mu g/m^3$. $PM_{2.5}$ concentration increased from 39 $\mu g/m^3$ during 2019 to 49 $\mu g/m^3$ which is well within the standard limit of 80 $\mu g/m^3$. SO2 concentrations increased from 27 $\mu g/m^3$ in 2019 to 37 $\mu g/m^3$ during February 2021 & NO_x concentrations increased from 18 $\mu g/m^3$ in 2019 to 44 $\mu g/m^3$ which is also within the standard limit of 80 $\mu g/m^3$.

3.2 Stationary source monitoring

Besides, ambient air quality monitoring, emissions from emission stacks of the plant were also quantified. The pollutants such as PM, O_2, CO, CO_2, SO, and NO_x were measured. Details of the stack monitoring are presented in Table 4. The stack monitoring was carried out during 23rd January to 6th February 2021.Stack sampler kit, M 500 (Enerac Instruments, USA) was used to measure the pollutant emission under isokinetic condition. A typical sampling system comprises of sampling probe, sample collection module, sampling control module, and a sampling pump. The condition of sampling under isokinetic conditions is not mandatory for the sampling of gaseous pollutants. The instrument also has the advantage of printing the real time data with all the necessary parameters in the field which can be used for reference purposes. Emission stack monitoring details are given in Table 16.

Table 16 Stack emission details

Sl. No.	Date	Stack Tag No	Stack detail	Stack Dia., m	Stack Height, m
I)	Refinery - II				
1	23.01.2021	14F1	Foots oil mix	1.24	32.38
2	23.01.2021	14 F 101	Wax Hydro finishing	1.19	42.7

3	25.01.2021	15F1A	ADU	2.60	63.41
4	25.01.2021	15F2 A	VDU	1.45	32
5	25.01.2021	15F2 B	VDU	1.45	32
6	27.01.2021	15F1B	ADU	1.70	60
7	27.01.2021	16F1	FCCU	1.80	58.2
8	27.01.2021	16F3	FCC CO boiler	1.78	60
II)	Refinery - I				
9	27.01.2021	10F101	Lube Hydro-finishing	1.19	42.7
10	28.01.2011	9F201	DWO mix	1.48	47.93
11	28.01.2011	9F301	Slack wax mix	1.02	36.4
12	28.01.2011	1F1A East	ADU	2.60	63.4
13	28.01.2011	1F1A West	ADU	2.60	63.4
III)	LEB				
14	29.01.2011	71 F1	PDA Feed	1.16	45.82
15	29.01.2011	73F101	NMP 1	1.62	53.38
16	29.01.2011	73 F102	NMP 2	1.66	48.85
17	29.01.2011	76F11	Naptha reformer	1.50	49.25
18	29.01.2011	77 F1	DHDS	1.50	49.25
IV)	Refinery-III				
19	30.01.2021	201F1/F2	Ref-III ADU/VDU	3.45	70
20	30.01.2021	205 F1	HGU	1.78	60
21	30.01.2021	205 F2	HGU	1.78	60
22	30.01.2021	206 F1-F2	CRU Feed	1.80	60
23	30.01.2021	206 F3-F6	CRU	1.80	60
24	30.01.2021	207F1	OHCU Fractionator	1.72	70
25	30.01.2021	212 F1	ISOM feed	1.8	60
26	01.02.2021	Gas Turbine	HRSG 1	1.80	70

27	01.02.2021	Gas Turbine	HRSG 2	1.80	70
28	01.02.2021	Gas Turbine	HRSG 3	1.80	70
29	02.02.2021	207 F101	OHCU Fractionator	1.72	30
30	02.02.2021	207F201	OHCU Fractionator	1.8	35
31	02.02.2021	Boiler-1	Cogeneration plant	1.80	90
32	02.02.2021	Boiler-3	Cogeneration plant	1.80	90
33	02.02.2021	Boiler-4	Cogeneration plant	1.80	90
34	03.02.2021	Gas Turbine	HRSG 4	1.80	70
35	03.02.2021	86F1	DCU Heater	3.0	70
36	04.02.2021	1F1B	ADU	1.46	60
37	04.02.2021	1F3	VDU	1.20	55.58
38	05.02.2021	214 F1	Naptha heater	1.80	70.00
39	05.02.2021	211 F-1	DHDT feed	1.8	60
40	06.02.2021	206F1	CRU Feed	1.80	60
41	06.02.2021	206 F2	CRU Feed	1.80	60
42	Shut Down	14F1	Kero ATF	2.6	37.80
43	Shut Down	3F1	Diesel HDS	1.74	30.00
44	Shut Down	78F1	DHDS SRU Furnace	1.80	60.00
45	Shut Down	206F1	CRU	1.80	60.00
46	Shut Down	Boiler-2	Cogeneration plant	1.80	90.00
47	Shut Down	Boiler-5	Cogeneration plant	1.80	90.00
48	Shut Down	216F1	Steam Reformer	1.80	70.00
49	Shut Down	LP2	DHDS	1.20	55.58

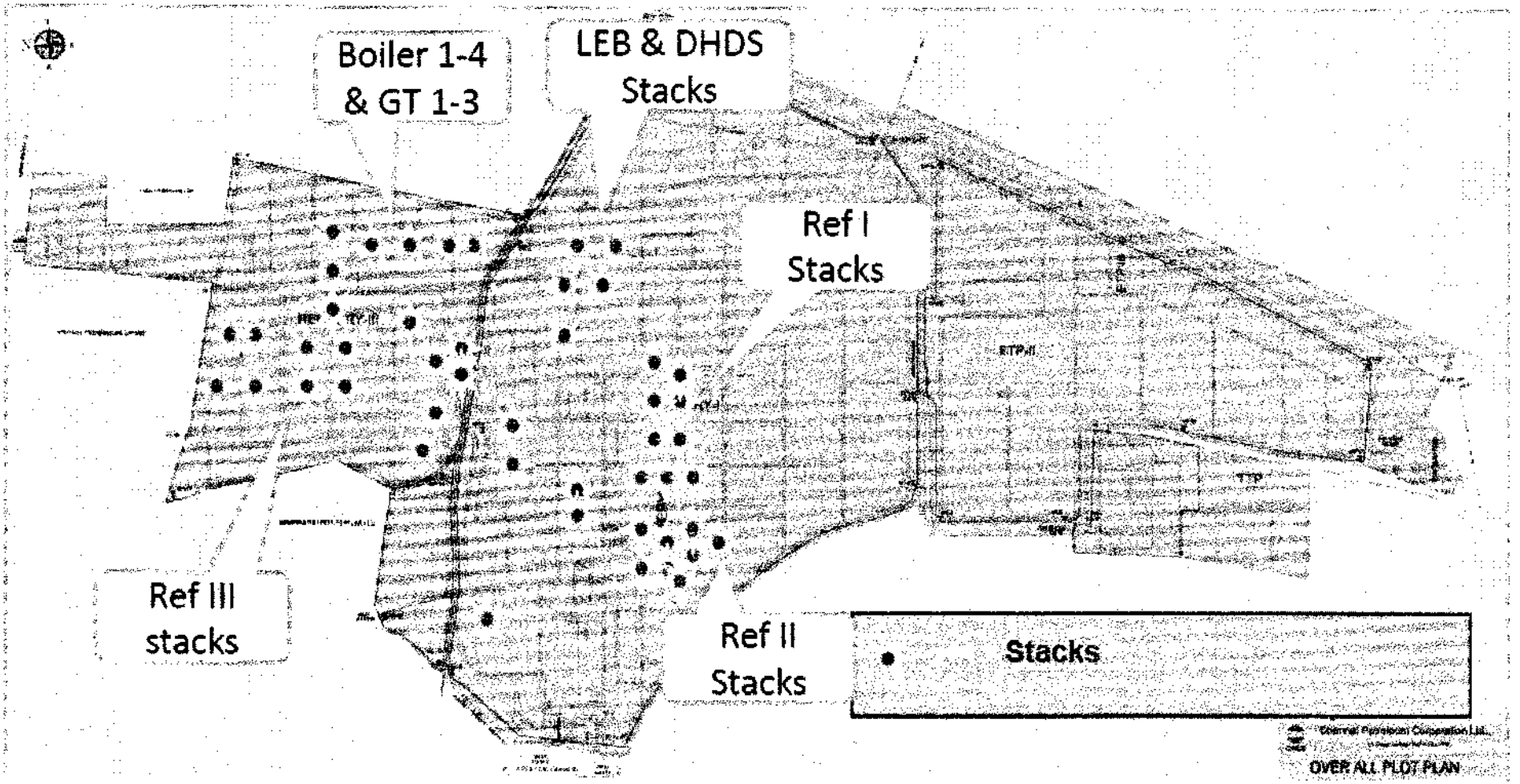


Figure 7 Stack locations

3.2.1 Measurement of PM from stationary sources

The measurement of particulates emission from the stacks was carried out by collecting particulate samples and determining parameters like flue temperature, pressure, velocity, and flow rate at selected traverse sampling points using a stack monitoring kit. The number of traverse points required for sampling was selected as per Indian Standard Method for Air Pollution, IS 11255 (Part 3):2008 rules. The velocity and flowrate were determined as per IS 11255 (Part 3):2008 guidelines. For the sampling of PM, IS 11255 (part 1):2008 was used. All the particulate samplings were carried out isokinetically for suitable periods under normal operational conditions. The PM concentrations were estimated by gravimetric analysis of particulate collection thimbles and subsequently, the emission rates of particulates were determined. The removal of moisture from the stack effluents is mandatory before their entry into the control module.

3.2.2 Measurement of gaseous pollutants from stationary sources

The digital flue gas analyser, FEL-7 was used to measure the levels of CO_2, O_2, CO and NOx. The analyser uses infra-red light at a particular frequency which is absorbed by gases molecules, capturing the absorbance using an infra-red detector, gases concentration can be estimated. The sampling was carried out for 20 mins with a flow rate of 1.5 litres/min.

Determination of sulphur dioxide emission from the stack was carried out as per the stipulations of IS 11225 (part 2):1985 which is similar to the US EPA Method 6. In this method, a gas sample is extracted from the sampling point in the stack. The SO_2 and the sulfur trioxide, including those fractions in any sulfur acid mist, are separated. The SO_2 fraction is then measured by the barium-thorin titration method. The sampling was carried out for 30 mins with a flow rate of 2 litres/min. Standard methods for stack emission measurements were shown in Table 17 with their permissible limits as per CPCB. The results of stack gas emission monitoring are given in Table 18.

Table 17 Methods for Stack emission measurements

Sl. No.	Parameters	Units	Test Method	Limit as per CPCB standard	
				Gas	Liquid
1.	Stack Temperature	K	IS 11255 (Part –3):2008	-	-
2.	Velocity	m/sec	EPA Method 1-3	-	-
3.	Volume of Gas Discharge	Nm^3/hr	IS 11255 (Part –3):2008	-	-
4.	Oxygen as O_2	%	GL/EN/SOP/149	-	-
5.	Carbon Monoxide as CO	mg/m^3	GL/EN/SOP/149	100	200
6.	Carbon Dioxide as CO_2	%	GL/EN/SOP/149	-	-
7.	Particulate Matter	mg/Nm^3	GL/EN/SOP/149	10	100
8.	Sulphur Dioxide as SO_2	mg/m^3	EPA Method 6	50	1700
9.	Oxides of Nitrogen as NO_2	mg/m^3	GL/EN/SOP/149	350	450

Table 18 Measured Air Quality Emissions at Various Stacks of CPCL

Sl. No.	Stack No	Stack detail	Temp K	Velocity m/sec	Gas volume Nm^3/hr	O_2 %	CO_2 %	CO mg/Nm^3	PM mg/Nm^3	SO_2 mg/Nm^3	NO_x in terms of NO_2 mg/Nm^3
1	14F1	Foots oil mix	788	12.3	20067	8.1	11.6	152	15.4	116	356
2	14 F 101	Wax Hydro finishing	769	14.08	21669	9.6	10.5	140	8.1	42	331
3	15F1A	ADU	431	7.3	95678	11.2	8.6	149	17.9	76	142
4	15F2 A	VDU	630	9.95	27750	8.3	10.5	103	19.4	59	172
5	15F2 B	VDU	536	11.21	36747	7.9	11.3	84	20.3	186.9	192
6	15F1B	ADU	457	8.46	44656	9.4	11.5	103	19.4	59	172
7	16F1	FCCU	456	10.74	63804	9.4	10.8	148	17.4	59.1	408
8	16F3	FCC CO boiler	671	14.99	59179	6.2	11.9	142	9.7	10.2	43
9	10F101	Lube Hydro-finishing	641	9.8	18099	11.3	6.9	111	19.1	40.8	232
10	9F201	DWO mix	417	7.32	32147	11.2	9.4	185	24.4	41	421
11	9F301	Slack wax mix	509	9.46	16143	8.6	10.1	159	25.6	71.4	425
12	1F1A East	ADU	468	8.02	97096	14.5	4.8	60	14.5	164	125
13	1F1A West	ADU	481	8.51	100204	14.5	4.8	56	12.4	149.4	101
14	71 F1	PDA Feed	589	7.79	14932	7.8	10.1	143	29.7	157.3	335

Sl. No.	Stack No	Stack detail	Temp K	Velocity m/sec	Gas volume Nm^3/hr	O_2 %	CO_2 %	CO mg/Nm^3	PM mg/Nm^3	SO_2 mg/Nm^3	NO_x in terms of NO_2 mg/Nm^3
15	73F101	NMP 1	457	7.95	38271	10.9	9.5	135	27	51.4	94
16	73 F102	NMP 2	423	6.8	37144	12.7	6.4	15	15.8	10.3	16
17	76F11	Naptha reformer	527	30.7	109903	2.5	13.7	152	33.1	20.6	33
18	77 F1	DHDS	578	10.21	33369	9.6	8.4	31	18.4	20.7	60
19	201F1/F2	Ref-III ADU/VDU	628	18.5	293982	3.6	12.7	180	14.4	367.1	239
20	205 F1	HGU	471	5.93	33448	11.2	5.9	56	8.2	18	55
21	205 F2	HGU	432	14.4	88556	6.1	13.5	11	24.9	7.7	25
22	206 F1-F2	CRU Feed	571	6.28	29911	6	11.3	23	15.8	258.8	217
23	206 F3-F6	CRU	581	13.76	64247	12.1	7.2	49	9.8	84.4	230
24	207F1	OHCU Fractionator	667	9.4	34991	6.2	11.4	13	9.3	7.7	31
25	212 F1	ISOM feed	436	6.3	39245	5.2	11.6	54	8.9	47	27
26	Gas Turbine 1	HRSG 1	427	10.84	69013	14.5	5.1	2	28.2	12.9	12
27	Gas Turbine 2	HRSG 2	422	10.84	69812	15.8	3.7	6	22.2	10.3	10
28	Gas Turbine 3	HRSG 3	435	10.05	62807	15.2	4	8	26.9	15.4	16
29	207 F102	OHCU Fractionator	450	5.2	28718	6.4	11.1	17	15.6	437.3	167

Sl. No.	Stack No	Stack detail	Temp K	Velocity m/sec	Gas volume Nm^3/hr	O_2 %	CO_2 %	CO mg/Nm^3	PM mg/Nm^3	SO_2 mg/Nm^3	NOx in terms of NO_2 mg/Nm^3
30	207F201	OHCU Fractionator	487	6.14	34302	4.5	12.9	BDL	8.9	BDL	BDL
31	Boiler-1	Cogeneration plant	454	15.1	90370	8.4	9.4	40	57.3	922.4	368
32	Boiler-3	Cogeneration plant	465	15.7	91580	9.8	8.2	28	60.5	998	272
33	Boiler-4	Cogeneration plant	453	15.6	933556	3.1	13.2	12	53	943	400
34	Gas Turbine 4	HRSG 4	421	14.9	96150	16.4	3.4	11	17.4	5.1	32
35	86F1	DCU Heater	445	4.8	81421	6.4	10.7	11	8.6	BDL	71
36	211F1	ADU	482	9.4	34829	10.8	8.6	124	23.7	49	29
37	1F1B	VDU	430	11.46	32148	8.2	9.6	13	22.9	48.8	232
38	206F1	Naptha heater	437	21.58	134818	4	12.9	BDL	9.4	2.12	193
39	206F2	DHDT feed	440	5.5	399948	14	4.9	6	9.8	289	272
40	214F1	VDU	538	5.66	12714	6.1	11	7	9.1	BDL	29
41	1 F3	CRU Feed	557	5	24413	7.9	9.7	BDL	18.2	229.2	191

BDL – Below Detectable limit

Table 19 Stack emission conducted by TNPCB during 2017-218 and 2018-19

S. No.	Stack Details	Height, m	Stack survey 2017-2018, mg/m³			Stack survey 2018-2019, mg/m³			IITM measurements		
			PM	SO_2	NO_2	PM	SO_2	NO_2	PM	SO_2	NO_2
1	Boiler 1	100	48	684	309	52	364	207	57.3	922.4	368
2	Boiler 2	100	Not done			Not done			Not done		
3	Boiler 3	100	Not done			45	743	302	60.5	998	272
4	Boiler 4	100	51	508	234	53	1234	425	53	943	400

Table 19 shows the stack emission monitoring conducted by TNPCB during the year 2017-18 and 2018-19. TNPCB had monitored 3 number of Power & Utility stacks for three pollutants such as PM, SO_2 and NO_2. From comparison with our measurements carried out during February 2021, it was found that PM concentration increased in most of the stacks but well within the standard limit of 100 mg/Nm^3. SO_2 concentrations increased in most of the stack in comparison with TNPCB measurements. Stack emissions for NO_2 concentrations decreased in comparison for 2017-18 and 2018-19 for the Boiler – 3 & 4 stacks and are well within the permissible limit of 450 mg/m^3.

4. Conclusions and Recommendations

The stack monitoring and Ambient air quality monitoring in the CPCL premises was done during January to February2021. Stack monitoring was carried out for 41 stacks which were operating during the period of measurement. A total of 8 stack was not in operation during the period of measurements and hence these stack monitoring was not carried out. The continuous ambient air quality monitoring at 10 strategic locations has been completed, each for four-week duration with two readings per week. From the analysed results, it was found that all the air pollutants are well within the permissible limits as prescribed by NAAQS.

It is found that none of the air quality parameters of stack emission as well as ambient air quality exceeds the permissible limits prescribed by MoEF & CC vide notification dated 18th March 2008 specific to "OIL REFINERY INDUSTRY" under section 'B', for the existing refineries, and the NAAQ standards, respectively.

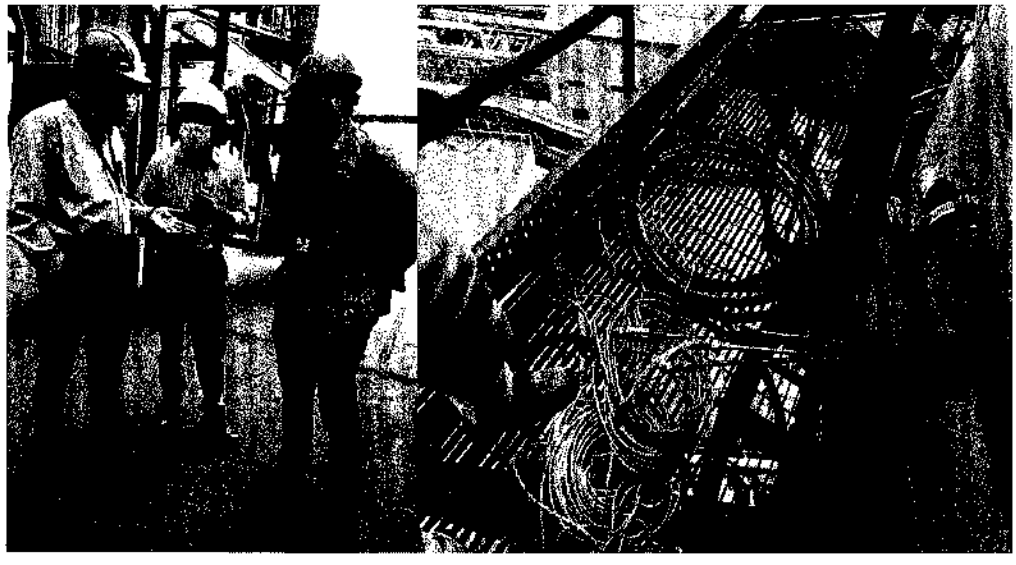
The following recommendations are provided for improving the air quality in the CPCL premises.

1. CPCL has already taken initiatives to reduce 30-40 % of the SO_2 emission by commissioning & utilizing RLNG in most of the furnaces and reduced Fuel oil consumption. The quantity of RLNG has increased gradually from 9000 MT in April 2019 to 30000 MT in Dec 2020. The same shall be continued/ increased to keep the SO_2 emission under control.
2. CPCL should install solar panels wherever possible to meet a part of power requirements inside the premises.
3. CPCL should install VOC adsorption system in ETP-3 to control fugitive emissions
4. Double seal arrangement has been provided in all Class A product tanks in CPCL to combat Emissions from storage and the same shall be maintained.
5. Personal LDAR-monitors and on-line measurements, monitoring campaigns and risk assessment procedures, availability of protective equipment as well as training programs are effective tools in the monitoring and management of exposure for employees/workers.
6. One of the important sources of fugitive emission is vehicular movement in the vicinity area which should be addressed by introducing Electrical vehicles/ CNG based vehicles inside the CPCL premises.
7. Dust- suppression system should in place wherever there is vehicle movement inside the premises which controls fugitive dust emissions.
8. The monitoring of the air quality needs to be carried out once in six months by a reputed institution like IIT and Anna University.

(Dr. S. Mohan)

Annexure

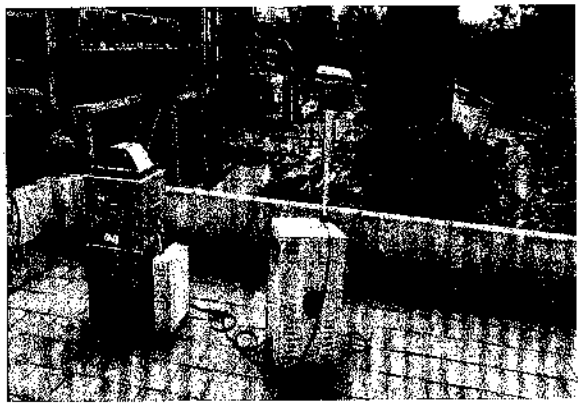
Photos during site visit by IIT-M Team

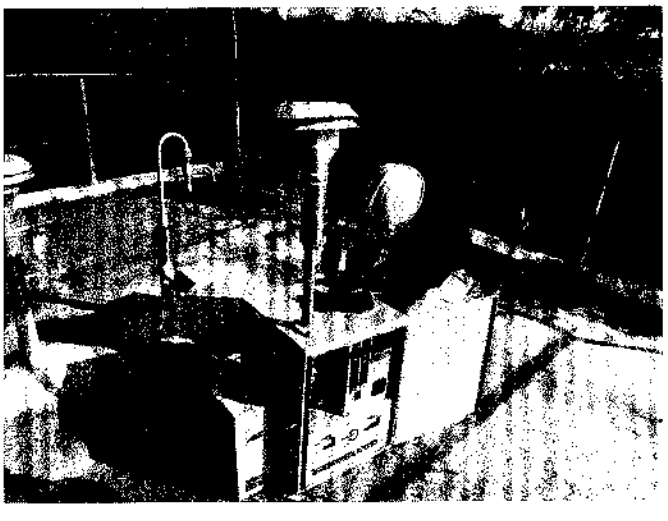


Stack monitoring at the sampling point

Stack monitoring at the sampling point

Ambient air quality monitoring at the sampling point





Ambient air quality monitoring samples ($PM_{2.5}$ and PM_{10})