

Visakh Refinery Modernization Project (VRMP) at Visakhapatnam

HPCL is planning to expand capacity of its Visakh Refinery to 15 MMTPA along with the associated facilities for residue up gradation and products quality up gradation incorporating advanced refining technologies for modernisation. The VRMP implementation at Visakh Refinery will enable to meet the multifarious challenges like increased product demand, energy conservation, stringent safety and improved quality of MS & HSD.

Earlier, HPCL has submitted application for TOR approval Vide letter reference no. CEE/13/AJ/VRMP/218 dated Jan 16, 2013 and the project matter was discussed in 7th reconstituted EAC (I) meeting held during April 4-5, 2013. However, project proposal was not considered for award of "Terms of Reference" due to ongoing moratorium. The project has been on hold for for approx. 2 years.

As per MoEF Letter F. No. J-11013/5/2010-IA II (I) dated Sep 17, 2013, Moratorium has been lifted from Visakhapatnam (Andhra Pradesh). Subsequently, project was considered in the 14th Reconstituted EAC (Industry) meeting held during Dec 19th-20th, 2013; however, the proposal was deferred for consideration and EAC advised to carry out Quantitative Risk Assessment (QRA) Study and feasibility of Coal based power generation. HPCL engaged EIL to carry out QRA Study and M/s Tata Consulting Engineers for feasibility study of Coal based power generation.

As per the recommendation of the Reconstituted Expert Appraisal Committee (Industry) in its 18th meeting in April 2014, a Sub-committee of EAC visited site of HPCL Vishakhapatnam wherein preliminary findings of QRA study and Coal base power plant feasibility study were presented to EAC Members. Based on the site visit recommendations, TOR has been granted to HPCL vide MoEF vide letter F. No J-1101/63/2013 -IA II (I) dtd Sep18, 2014.

During the revalidation of DFR, there has been minor changes in the process unit capacities and layout (attached). Comparison of main process units' capacities in earlier DFR & current DFR has been tabulated below:

Sr. No.	Processing Unit	Unit	Capacity as per Previous DFR (2012)	Capacity as per Current DFR (2014)
1.	CDU / VDU	MMTPA	9	9
2.	ALKYLATION UNIT*	KTPA	200	200
3.	FULL CONVERSION HCU	MMTPA	2.8	3.3
4.	SOLVENT DEASPHALTING	MMTPA	2.5	3.1
5.	SLURRY HYDROCRACKER UNIT	MMTPA	2.8	2.5
6.	PRU	TPD	128	96
7.	NAPHTHA ISOMERISATION UNIT (Existing: 229 KTPA)	KTPA	69 Revamp 30%	292 (New Unit)

*Alkylation Unit is phased out in current DFR; provision for Alkylation Unit shall be considered at the time implementation of BS-V norms for MS. Revamp of existing NHT and CCR Units has been considered minimum 30%.

The Coal based power plant which was proposed to be located in the close vicinity of the Refinery could not be taken forward due to the height restriction imposed by Eastern Naval Command. For meeting power requirement, total Captive power plant with natural gas and naphtha as fuel to GTGs and feed/fuel to Hydrogen Generation Units has been considered. Other major changes are listed below:

- No facility has been considered in VPT plot (Plot I) near INS Dega
- The proposed project requires total water consumption of 784 cum/hr (18.82 MLD).
- Under this project, an Integrated Effluent Treatment Plant (inclusive of existing refinery effluent streams treatment) is proposed. As a measure of conservation of natural resources, it is considered that based on an estimated total effluent of ~ 800 cum/hr post refinery expansion, approx. 665 cum/hr of water is expected to be recycled. However, this quantity (in ratio) will vary based on the refinery requirement. Reject shall be used as make up water in cooling towers.
- From the proposed facilities, about 332 m³/hr of industrial wastewater (max) and 30 m³/hr of sanitary wastewater will be generated

Based on above, Form-I has been revised and attached for kind consideration.

FORM-1

(As per MoEF Notification S. O. 1533 (E), Dated 14th September, 2006 and Amendment Notification dated 12.1.2009)

(I) Basic Information

Sl.No	Item	Details
1.	Name of the Project	Visakh Refinery Modernization Project (VRMP)
2.	S. No. in the schedule	4(a)
3.	Proposed capacity / area / length / tonnage handled / command area / lease area / number wells to be drilled	Expansion of existing Visakh Refinery Crude Processing Capacity of 8.33 MMTPA (Million Metric Tonnes Per Annum) to 15.0 MMTPA. Refer Annexure-I (Executive Summary) for details.
4.	New / Expansion / Modernization	Expansion & Modernization
5.	Existing Capacity / Area etc.	8.33 MMTPA Crude Processing
6.	Category of Project i. e ' A' or 'B'	A
7.	Does it attract the general condition? If yes, please specify	No
8.	Does it attract the specific condition? If yes, please specify.	No
9.	Location	The locations identified for the Project are : <ul style="list-style-type: none">• Within existing Refinery premises• Contiguous area east side of existing Refinery (after re-siting HPCL Marketing Terminal & LPG bottling plant).• Approx. 50 Acres of Visakhapatnam Port Trust (VPT) leased plots north of existing Refinery (near HPCL-Additional Tankage Project).
	Plot / Survey / Khasra No.	

SI.No	Item	Details
	Village	Malkapuram, Visakhapatnam
	Tehsil	Visakhapatnam
	District	Visakhapatnam
	State	Andhra Pradesh
10.	Nearest railway station / airport along with distance in kms	1. Visakhapatnam Railway Station (~6.5 Km) 2. Visakhapatnam Airport (~5.0 Km)
11.	Nearest Town, City, District Headquarters along with distance in kms	Visakhapatnam (~7.0 Km)
12.	Village Panchayats, Zilla Parishad, Municipal Corporation, Local body (complete postal address with telephone nos to be given)	Greater Visakhapatnam Municipal Corporation (GVMC) Tenneti Bhavanam , Asilmetta Junction Visakhapatnam- 530002, Andhra Pradesh. Telephone: 0891-2568545(O), 0891-255100/ 2569335/36(O)
13.	Name of the Applicant	Executive Director – Refineries Project Process
14.	Registered Address	Petroleum House, PH-5 17, Jamshedji Tata Road, Churchgate, Mumbai, Maharashtra, Pin Code- 400020
15.		
(i)	Name	Mr. S. C.Mehta
	Designation	Executive Director – Refineries Projects Process
	Address	Petroleum House, PH-6 17, Jamshedji Tata Road, Churchgate, Mumbai, Maharashtra, Pin Code- 400020
	Pin Code	400020
	Email	scmehta@hpcl.in
	Telephone No	022-22839934

SI.No	Item	Details
(ii)	Fax No	022-22811671
	Name	Mr. V. Ratan Raj
	Designation	Deputy General Manager - Process, (Central Engineering).
	Address	Petroleum House, PH-6 17, Jamshedji Tata Road, Churchgate, Mumbai, Maharashtra, Pin Code- 400020
	Pin Code	400020
	Email	ratan@hpcl.in
	Telephone	022-22863607
	Fax	022-22025140
16.	Details of Alternative Sites examined, if any. Location of these sites should be shown on a topo sheet	No
17.	Interlinked Projects	No
18.	Whether separate application of interlinked project has been submitted?	Not Applicable
19.	If yes, date of submission	Not Applicable
20.	If no, reason	Not Applicable
21.	Whether the proposal involves approval / clearance under: if yes, details of the same and their status to be given. (a) The Forest (Conservation) Act, 1980? (b) The Wild life (Protection) Act, 1972? (c) The C. R. Z Notification, 1991?	Not applicable
22.	Whether there is any Government Order / Policy relevant / relating to the site?	No
23.	Forest land involved	No

SI.No	Item	Details
24.	<p>Whether there is any litigation pending against the project and / or land in which the project is propose to be set up?</p> <p>(a) Name of the Court</p> <p>(b) Case No.</p> <p>(c) Orders?</p> <p>Directions of the Court, if any and its relevance with the proposed project.</p>	No

(II) Activity

- 1. Construction, operation or decommissioning of the Project involving actions, which will cause physical changes in the locality (topography, land use, changes in water bodies, etc.)**

S.No	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities /rates, wherever possible) with source of information data
1.1	Permanent or temporary change in land use, land cover or topography including increase in intensity of land use (with respect to local land use plan)	Yes	<p>Existing Visakh refinery is located on 723 acres of land situated 1 km Northward from the foot of Yarada hills have cluster of industries.</p> <p>Proposed facilities are envisaged (a) within the existing refinery complex (b) relocated marketing terminal, LPG bottling plant & (c) Approx. 50 Acres of HPCL acquired lease land from Visakhapatnam Port Trust as indicated in Item (9) under 'Basic Information'</p> <p>The leased VPT land area will be used for petroleum storages.</p>
1.2	Clearance of existing land, vegetation and buildings?	Yes	No clearance of vegetation is envisaged. Proposed facilities are within refinery with relocation of Service buildings (Ware house, Sub-stations, Electrical switchyard etc.)
1.3	Creation of new land uses?	Yes	<ul style="list-style-type: none"> Proposed facilities are envisaged where Petroleum Tanks and LPG Bottling Plant

S.No	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities /rates, wherever possible) with source of information data
			<p>existed as part of HPCL Marketing facilities. These facilities are re-sited to create contiguous plot with existing refinery.</p> <ul style="list-style-type: none"> Approx. 50 Acres Visakhapatnam Port Trust lease land acquired by HPCL for petroleum storage.
1.4	Pre-construction investigations e.g. bore houses, soil testing?	Yes	Soil at refinery area is sandy clay loam type with moderate water holding capacity. Detailed soil testing shall be done for proposed/existing locations as per the requirements.
1.5	Construction works?	Yes	Construction for proposed project facilities are confined to the identified project sites referred above viz., within refinery, adjacent contiguous plot and in VPT leased areas.
1.6	Demolition works?	Yes	Please refer Section 1.2 above for details
1.7	Temporary sites used for construction works or housing of construction workers?	No	Visakhapatnam being large town, the requirement of construction workers shall be sourced from urban and sub-urban areas. Hence, no provision for housing for construction workers anticipated.
1.8	Above ground buildings, structures or earthworks including linear structures, cut and fill or excavations	Yes	Project related civil and mechanical construction works shall be carried out in those areas identified where the project facilities are envisaged.
1.9	Underground works including mining or tunneling?	No	Culverts are envisaged as part of road crossing for pipelines.
1.10	Reclamation works?	No	-
1.11	Dredging?	No	-
1.12	Offshore structures?	No	-

S.No	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities /rates, wherever possible) with source of information data
1.13	Production and manufacturing processes?	Yes	Refer Annexure-II (Process Unit Description) for details.
1.14	Facilities for storage of goods or materials?	Yes	Refer Annexure-III (Offsite System) for details.
1.15	Facilities for treatment or disposal of solid waste or liquid effluents?	Yes	Refer Annexure-IV (Environmental Consideration) for details.
1.16	Facilities for long term housing of operational workers?	No	Existing residential township is adequate.
1.17	New road, rail or sea traffic during construction or operation?	Yes	Similar to existing refinery, crude and products movement to and from the refinery shall be through pipelines. The existing infrastructure available will be utilized to the maximum extent possible. There will be some incremental road/sea traffic movement owing to movement of materials during construction phase and operation. This is temporary and limited to the period of construction of the project.
1.18	New road, rail, air waterborne or other transport infrastructure including new or altered routes and stations, ports, airports etc?	No	-
1.19	Closure or diversion of existing transport routes or infrastructure leading to changes in traffic movements	No	-
1.20	New or diverted transmission lines or pipelines?	Yes	The existing Refinery pipeline facilities shall be utilized to the maximum extent possible. Existing High Tension Line south of VPT area which is proposed for use in the project have

S.No	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities /rates, wherever possible) with source of information data
			to be re-routed as per requirement of the concerned authority.
1.21	Impoundment, damming, culverting, realignment or other changes to the hydrology of watercourses or aquifers?	No	-
1.22	Stream crossings?	No	-
1.23	Abstraction or transfers of water form ground or surface waters?	No	-
1.24	Changes in water bodies or the land surface affecting drainage or run-off?	No	-
1.25	Transport of personnel or materials for construction, operation or decommissioning?	Yes	There shall be transportation of men and materials during construction of the proposed facilities and decommissioning of the existing redundant facilities. However, these movements are confined mostly to existing refinery area and those proposed areas where the facilities are envisaged.
1.26	Long-term dismantling or decommissioning or restoration works?	No	-
1.27	Ongoing activity during decommissioning which could have an impact on the environment?	Yes	The decommissioning of the existing facilities shall be done in a controlled manner to limit the impact on the environment. These impact will be confined within the existing refinery premises and no other significant impact on environment is anticipated.
1.28	Influx of people to an area in either temporarily or permanently?	No	-
1.29	Introduction of alien species?	No	-

S.No	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities /rates, wherever possible) with source of information data
1.30	Loss of native species or genetic diversity?	No	-
1.31	Any other actions?	No	-

2. Use of Natural resources for construction or operation of the Project (such as land, water, materials or energy, especially any resources which are non-renewable or in short supply):

S.No.	Information/checklist confirmation	Yes/No	Details thereof (with approximate quantities /rates, wherever possible) with source of information data
2.1	Land especially undeveloped or agricultural land (ha)	Yes	
2.2	Water (expected source & competing users) unit: MLD	Yes	<p>The proposed project requires total water consumption of 784 Cum/hr (18.82 MLD).</p> <p>Under this project, an Integrated Effluent Treatment Plant (inclusive of existing refinery effluent streams treatment) is proposed. As a measure of conservation of natural resources, it is considered that based on an estimated total effluent of ~ 800 Cum/hr post refinery expansion, approx. 665 Cum/hr of water is expected to be recycled. However, this quantity (in ratio) will vary based on the refinery requirement. However, these are estimated figures at DFR stage, later during design and operation phase, the figures may vary".</p> <p>Reject shall be used as make up water in Cooling towers.</p>
2.3	Minerals (MT)	No	-

S.No.	Information/checklist confirmation	Yes/No	Details thereof (with approximate quantities /rates, wherever possible) with source of information data
2.4	Construction material – stone, aggregates, sand / soil (expected source – MT)	Yes	Mostly mechanical erection and technological structures. However, for piling and civil foundation minimum amount of soil, sand/soil will be used.
2.5	Forests and timber (source – MT)	No	
2.6	Energy including electricity and fuels (source, competing users) Unit: fuel (MT), energy (MW)	Yes	The Power and Steam required are generated in-house (within the Refinery using naphtha/ natural gas / fuel gas/fuel oil based on availability and optimized utilization of process heat systems). Refer Annexure-V (Utilities Description) for Power Plant Configuration details. Efforts are being initiated to obtain dedicated power with independent transmission line through grid. This facilitates improved margin and reduction of naphtha/natural gas usage considerably.
2.7	Any other natural resources (use appropriate standard units)	Yes	Total crude oil of 15 MMTPA will be imported after implementation of proposed facilities.

3. Use, storage, transport, handling or production of substances or materials, which could be harmful to human health or the environment or raise concerns about actual or perceived risks to human health.

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data
3.1	Use of substances or materials, which are hazardous (as per MSIHC rules) to human health or the environment (flora, fauna, and water supplies)	Yes	The proposed project is expansion of existing refinery and shall be handling similar hazardous substance or materials as they are being handled in existing refinery. All the hazardous substances of the proposed project shall be handled complying with the latest MSIHC rules.

3.2	Changes in occurrence of disease or affect disease vectors (e.g. insect or water borne diseases)	No	-
3.3	Affect the welfare of people e.g. by changing living conditions?	Yes	Existing Refinery has an operational social and economic development plan which aims toward welfare of the surrounding inhabitants. The welfare activities under the proposed project will be integrated with the existing social and economic development plan. Significant contribution to socio-economic conditions and improved welfare to the people due to direct/ indirect employment, business opportunities during construction & operation phase. Besides socio-economically, with the production of Clean Fuels (Viz., BS IV and V grades for MS and HSD) due to modernization aspects considered in the proposed project, overall improvement and sustainability in the environment is envisaged.
3.4	Vulnerable groups of people who could be affected by the project e.g. hospital patients, children, the elderly etc.,	No	-
3.5	Any other causes	No	-

4. Production of solid wastes during construction or operation or decommissioning (MT/month)

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities / rates, wherever possible) with source of information data
4.1	Soil, overburden or mine wastes	No	-
4.2	Municipal waste (domestic and or commercial wastes)	No	-
4.3	Hazardous wastes (as per Hazardous Waste Management	Yes	The following hazardous wastes are envisaged from the proposed project :

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities / rates, wherever possible) with source of information data
	Rules)		<p>(a) Spent catalysts (b) Oily Sludge (c) Spent Carbon</p> <p>With the incorporation of state-of-the-art Effluent Treatment Plant in the proposed project, the generation of sludge is around 1.5 TPD. The generated sludge will be thickened in a thickener and the thickened sludge will be dewatered in a centrifuge.</p> <p>The tank bottom sludge generated due to scheduled tank cleaning operation is around 1000 Metric Tons per Tank at the periodicity of 5 years.</p> <p>The above hazardous wastes will be sent /sold to Authorised Recyclers/Re-Processors/Re-users or disposed to authorized TSDF (Treatment, Storage & Disposal Facility) as per HW (MH&TM) Rules 2008 and Amendment thereafter.</p>
4.4	Other industrial process wastes	Yes	Other non-hazardous wastes viz., spent insulation, construction debris etc. which are generated in the proposed facility will be disposed as per Municipal Solid Wastes (M&H) Rules 2000 and Amendment thereafter.
4.5	Surplus product	No	All products will be marketed.
4.6	Sewage sludge or other sludge from effluent treatment	Yes	The proposed project envisaged to provide state-of-the-art effluent treatment system ensuring minimum generation of sludge. The bio sludge to the tune of 2 TPD from bio-treatment section will be separately thickened and dewatered in a thickener and centrifuge

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities / rates, wherever possible) with source of information data
			respectively. The dewatered sludge are either bioremediated and/or sent to authorized TSDF (Treatment ,Storage & Disposal Facility) as per HW (MH&TM) Rules 2008 and Amendment thereafter.
4.7	Construction or demolition wastes	Yes	All construction and demolition waste will be managed as part of Construction Management Plan by the construction contractor in accordance to the Health, Safety & Environment (HSE) plan approved by HPCL.
4.8	Redundant machinery or equipment	Yes	Efforts will be made to reclaim whatever redundant machinery/ equipment that are generated or otherwise it will be sold.
4.9	Contaminated soils or other materials	Yes	Suitable programme will be developed / followed if remediation / disposal become a requirement in case of large contaminants as per rules applicable.
4.10	Agricultural wastes	No	-
4.11	Other solid wastes	No	-

5. Release of pollutants or any hazardous, toxic or noxious substances to air (Kg/hr)

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data
5.1	Emissions from combustion of fossil fuels from stationary or mobile sources	Yes	The emissions from proposed project will meet the latest emission standard as applicable for Petroleum Oil Refinery. The proposed project is a part of

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data
			<p>existing refinery with the systems and facilities integrated. Current Refinery SO₂ emission norm stipulated is 11.5 TPD. The proposed project shall be designed such that even after the implementation of this project, the total SO₂ load from the refinery will be limited to 11.5 TPD. Please refer Annexure-IV (Environmental Consideration) for Sulphur Balance details.</p> <p>NO_x emissions from the proposed facilities shall be controlled through low NO_x burners in Heaters as per MoEF Notification dated March 18, 2008.</p>
5.2	Emissions from production processes	Yes	Please refer Section 5.1 above.
5.3	Emissions from materials handling including storage or transport	Yes	<p>Existing refinery is already handling and storing crude and products. Mitigation steps adopted in the existing refinery shall be extended to restrict the hydrocarbon emission for the products under proposed facilities as per stipulations in the latest Environmental Clearance obtained. Moreover, stipulations and practice as per the CPCB's Proposed Emission Standard for Petroleum Oil Refinery of 2008 shall be implemented for the proposed facilities.</p>
5.4	Emissions from construction activities including plant and equipment	Yes	<p>During construction, emissions are expected from mobile equipment such as transport vehicles and construction equipment like cranes, etc. The emissions from vehicles shall be monitored & controlled</p>

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data
			regularly. Moreover appropriate HSE plan shall be incorporated in the construction management of EPC contractor for minimization of these emissions.
5.5	Dust or odours from handling of materials including construction materials, sewage and waste	Yes	Dust and odour due to construction activities will be localized in nature within the existing refinery complex and relocated marketing terminal & LPG bottling plant area. In the VPT areas where larger amount of dust generation is envisaged, appropriate dust suppression methods shall be used if required.
5.6	Emissions from incineration of waste	No	-
5.7	Emissions from burning of waste in open air (e.g. slash materials, construction debris)	No	-
5.8	Emissions from any other sources	No	-

6. Generation of Noise and Vibration, and Emissions of Light and Heat:

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data with source of information data
6.1	From operation of equipment e.g. engines, ventilation plant, crushers	Yes	Noise level specification of various rotating equipment shall meet Occupational Safety and Health Association (OSHA) standards. Noise level at the battery limit shall comply with CPCB standards [Daytime 75 dB (A) and night time 70 dB (A)].

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data with source of information data
			Suitable enclosures shall be erected, if required, to minimize the impact of high noise generating sources.
6.2	From industrial or similar processes	Yes	<p>Noise level specification of various rotating equipment shall meet Occupational Safety and Health Association (OSHA) standards.</p> <p>Noise level at the battery limit shall comply with CPCB standards [Daytime 75 dB(A) and night time 70 dB(A)]. Protective gears will be used by occupational workers.</p> <p>Suitable enclosures shall be erected, if required, to minimize the impact of high noise generating sources.</p>
6.3	From construction or demolition	Yes	<p>Construction or demolition activities shall be carried out in the proposed areas as indicated in item no. 9 of Basic Information (I) above.</p> <p>Construction noise shall meet the CPCB norm at the plant battery limit [Daytime 75 dB (A) and night time 70 dB (A)].</p> <p>Protective gears will be used by occupational workers. Suitable enclosures shall be erected, if required, to minimize the impact of high noise generating sources.</p>
6.4	From blasting or piling	Yes	<p>Limited blasting and piling activities shall be carried out during proposed project. Acoustic barriers shall be installed if required.</p> <p>CPCB standards shall be adhered at the plant battery limit [Daytime 75 dB (A) and night time 70 dB (A)].</p>

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data with source of information data
6.5	From construction or operational traffic	Yes	<p>During construction phase, there will be incremental rise in traffic movement in the project area due to transportation of man and machine.</p> <p>In the operation phase, most of the products will be transported by pipeline; hence generation of noise during operation phase will be limited. A product dispatch management plan covering traffic management plan shall be delineated.</p>
6.6	From lighting or cooling systems	Yes	<p>All equipment shall meet the OSHA/ISO requirement under Indian Factory Act. Noise level at the Plant's battery limit shall comply with CPCB standards [Daytime 75 dB (A) and night time 70 dB (A)]. Fans and pumps will contribute some noise levels in the project area which will be within the permissible limit. However, they will be confined to acoustic enclosures; and therefore, contribution to ambient noise levels from plant operation will be low. Protective gears will be used by occupational workers.</p>
6.7	From any other sources	No	

7. Risks of contamination of land or water from releases of pollutants into the ground or into sewers, surface waters, groundwater, coastal waters or the sea:

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data
7.1	From handling, storage, use or spillage of hazardous materials	No	Hazardous materials handled during the proposed project will be similar to the waste handled in the existing refinery. Existing hazardous material handling plan covering safety measure and remedial measures shall be extended to proposed facility.
7.2	From discharge of sewage or other effluents to water or the land (expected mode and place of discharge)	Yes	<p>From the proposed facilities, about 332 m³/hr of industrial wastewater (max) and 30 m³/hr of sanitary wastewater will be generated and treated to meet the MINAS/other regulatory standards in the proposed effluent treatment plant and septic tank respectively.</p> <p>Treated effluent from Integrated Effluent Treatment Plant (IETP, for existing as well as new project) shall be further treated in the proposed new Tertiary Treatment Plant (TTP, RO based) for producing fresh water and DM water. Contaminated rain water after treatment meeting latest standard shall be disposed off to sea.</p> <p>Sanitary waste shall be handled as per the existing practice i.e. septic tank followed by soak pit for reuse in horticulture.</p>
7.3	By deposition of pollutants emitted to air into the land or into water	Yes	All emission shall comply with regulatory standard applicable. Emissions from the project are mostly non-toxic in nature. Hazardous pollutants shall be handled as per regulatory practices.
7.4	From any other sources	No	-

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data
7.5	Is there a risk of long term build up of pollutants in the environment from these sources?	No	-

8. Risk of accidents during construction or operation of the Project, which could affect human health or the environment

S.No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data
8.1	From explosions, spillages, fires etc from storage, handling, use or production of hazardous substances	Yes	The existing refinery has a Disaster Management Plan (DMP) and a Quantitate Risk Assessment (QRA) study in place. Quantitate Risk Assessment (QRA) and HAZOP study shall be carried out for the proposed project as per the regulatory requirement. This will be integrated with the existing DMP.
8.2	From any other causes	Yes	All safety measures / standards will be followed. Adequate training will be imparted to construction workers. Since, the proposed project is taken up as a part of the existing refinery system all existing refinery safety procedures shall be extended for the same.
8.3	Could the project be affected by natural disasters causing environmental damage (e.g. Floods, earthquakes, landslides, cloudburst etc)?	No	The proposed project facilities shall be designed complying with relevant National and International Standards. This shall consider appropriate design safety factors to take care of such natural eventualities/disasters.

9. Factors which should be considered (such as consequential development) which could lead to environmental effects or the potential for cumulative impacts with other existing or planned activities in the locality

S. No.	Information/Checklist confirmation	Yes/No	Details thereof (with approximate quantities/rates, wherever possible) with source of information data
9.1	Lead to development of supporting facilities, ancillary development or development stimulated by the project which could have impact on the environment e.g.: <ul style="list-style-type: none"> • Supporting infrastructure (roads, power supply, waste or waste water treatment, etc.) • housing development • extractive industries • supply industries • other 	No	-
9.2	Lead to after-use of the site, which could have an impact on the environment	No	
9.3	Set a precedent for later developments	No	It is expansion of existing refinery. However, introduction of new product (pitch) may result in development of ancillary industries in the region.
9.4	Have cumulative effects due to proximity to other existing or planned projects with similar effects	Yes	The proposed project is located within existing refinery site, which is in industrial belt of Visakhapatnam City.

(III) Environmental Sensitivity

S.No.	Areas	Name/ Identity	Aerial distance (within 10 km.)

S.No.	Areas	Name/ Identity	Aerial distance (within 10 km.)
1	Areas protected under international conventions, national or local legislation for their ecological, landscape, cultural or other related value	None	-
2	Areas which are important or sensitive for ecological reasons - Wetlands, watercourses or other water bodies, coastal zone, biospheres, mountains, forests	Coastal Belt of Bay of Bengal	Approx. 5 km from the coastline.
3	Areas used by protected, important or sensitive species of flora or fauna for breeding, nesting, foraging, resting, over wintering, migration	None	-
4	Inland, coastal, marine or underground waters	Coastal, Marine water	Approx. 5 km from the coastline.
5	State, National boundaries	No	-
6	Routes or facilities used by the public for access to recreation or other tourist, pilgrim areas	No	-
7	Defense installations	Eastern Naval Command (ENC)	ENC facilities approx. 1 km from the existing refinery complex, approx. 4 km from VPT leased land.
8	Densely populated or built-up area	Greater Visakh Municipal Corporation (GVMC)	The proposed project is envisaged within existing refinery site and in a contiguous and adjacent plot identified and VPT area which is located in the industrial belt of Visakhapatnam.
9	Areas occupied by sensitive man-made land uses (<i>hospitals, schools, places of worship, community facilities</i>)	School, Hospital & University	Schools and Hospitals exist within the 10 km area.

S.No.	Areas	Name/ Identity	Aerial distance (within 10 km.)
10	Areas containing important, high quality or scarce resources <i>(ground water resources, surface resources, forestry, agriculture, fisheries, tourism, minerals)</i>	No	The proposed project site is within part of refinery site and is appropriate for refinery establishment. The area has already cluster of industries around.
11	Areas already subjected to pollution or environmental damage. <i>(those where existing legal environmental standards are exceeded)</i>	No	These are areas where cluster of industries exist. Besides constant monitoring of the environmental discharges by Refinery Environmental team, local State Pollution and CPCB too monitors the Refinery for compliance of the environmental standards.
12	Areas susceptible to natural hazard which could cause the project to present environmental problems <i>(earthquakes, subsidence, landslides, erosion, flooding or extreme or adverse climatic conditions)</i>	No	-

(IV) Terms of Reference (TOR) for EIA study

I hereby given undertaking that the data and information given in the application and enclosures are true to the best of my knowledge and belief and I am aware that if any part of the data and information submitted is found to be false or misleading at any stage, the project will be rejected and clearance given, if any to the project will be revoked at our risk and cost.

Date: 06/01/2015

Place: MUMBAI





Executive Director
Refineries Project Process
HQO, HPCL
Mumbai-400020

1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Hindustan Petroleum Corporation Ltd. operates an 8.33 MMTPA refinery at Vishakhapatnam in the state of Andhra Pradesh.

The Visakh Refinery of HPCL is one of the most integrated refineries with three crude distillation units, MS Block (NHT/ISOM/CCR), Diesel Hydro Desulphurization unit, two Fluid Catalytic Cracking units, , Visbreaker Unit, Bitumen Blowing unit and Propylene Recovery unit. Currently the Refinery has installed Diesel Hydrotreater unit to comply with the Auto Fuel policy to meeting the Euro IV HSD product specification. The unit is under commissioning stage.

HPCL intends to further enhance its refining capacity up to 15 MMTPA under VRMP (Visakh Refinery Modernization Project). EIL was engaged as Consultant to carry out a Configuration Study and prepare a Detailed Feasibility Report. The same was completed and submitted to HPCL on September 2012. The basic process unit configuration finalized in the DFR under the selected case (Case 2A) were (a) A new Crude Distillation Unit (b) Full Conversion Hydrocracker as Secondary Processing unit and (c) Solvent Deasphalting and Slurry Hydrocracker as Bottoms Upgrade units.

As Visakh Region was under MoE&F environmental moratorium then, HPCL could not proceed with environmental Terms of Reference (TOR) approval activities. MoE&F lifted the environmental embargo on September, 2013.

HPCL has retained EIL's services for revision of this DFR to revalidate Capital cost and Financial Analysis with revised crude type, crude and product prices.

The capital cost estimate accuracy of this DFR is within $\pm 20\%$.

1.2 BACKGROUND FOR REVISION OF DFR

As the Environmental moratorium was in vogue at the Visakh region, subsequent project activities pertaining to Environmental Terms of Reference (TOR) submission to MoE&F could not take place immediately. The environmental embargo was lifted by MoE&F on September 17, 2013. The TOR application was put forth for the EAC Meeting held on December 20, 2013 and the Committee advised to complete a Risk Analysis for the project site facilities along with the existing refinery facilities. This Risk Analysis study is being taken up with M/s EIL separately.

Since the receipt of the VRMP DFR in September 2012, the following changes have taken place which directly or indirectly impacts the DFR with respect to financial analysis and process design considerations:

- a. Non-availability of the HPCL leased VPT plot (Plot I) near INS Dega as Eastern Naval Command (ENC) vide letter dated 15/7/13 has indicated that it proposes to expand its airbase. Therefore, the crude tanks (7 Nos) considered in this location are to be considered as 'not available'. Also, due to the proposed road widening, the balance availability of the plot purchased by HPCL from VPT (immediately close to ATP) will be known only after the re-survey which ENC has advised VPT to carry out.
- b. During the EAC Meeting for TOR approval, one of the Committee members advised to consider coal based power generation in lieu of naphtha which was considered in the DFR for power generation. A separate pre-feasibility study has been prepared by HPCL for 2 x 100 MW coal based power plant on co-generation mode.
- c. Revision in design crude especially high sulphur crude from Arab Heavy to Basrah Light based on sustained availability and parcel size.
- d. The US Dollar to Indian Rupees Forex rate have increased appreciably (In DFR 1 USD= Rs.45 was considered, whereas at present it is 1USD ~Rs.59.5)
- e. Consideration of recent set of pricing period ie., Financial years 2011-12, 2012-13 and 2013-14 (in VRMP DFR the pricing period was 2008-09, 2009-10 and 2010-11) for crude, products and utilities.

View above, M/s EIL is requested to prepare the revised DFR for VRMP project.

1.3 BASIC DESIGN PARAMETERS

1.3.1 Crude Mix

The following crude mixes are considered:

- **Design Crude Case:** 20 wt% Bonny Light+ 72wt % Basrah Light + 8wt% Doba.
- **Check Crude Case:** 20wt% Bonny Light+ 72wt % Basrah Light + 8wt% Maya.

Capital cost and financial analysis are worked out for design crude case and material balance and unit capacities are established for check crude case.

1.3.2 Refinery Capacity

The study is carried out for 15 MMTPA.

A new CDU of 9.0 MMTPA is considered in lieu of one of the existing low capacity old CDU. Therefore post VRMP, Refinery will be operating three CDUs as below:

- Existing CDUs :
 - CDU/VDU-II: 3.0 MMTPA
 - CDU/VDU-III: 3.0 MMTPA
- New CDU:
- CDU/VDU-IV : 9.0 MMTPA

The new CDU IV shall be designed for 86.7% Basrah Light and 13.3% Doba. Out of the two existing CDUs, one shall process 3.0 MMTPA of 100% Basrah Light and the other shall process 3.0 MMTPA of 100% Bonny light Crude.

1.3.3 On-Stream hours

The stream hour considered for the study is 8000 Hrs/Annum.

1.3.4 Objectives of the study

- Capacity Expansion of the refinery from 8.33 MMTPA to 15 MMTPA
- Minimization of naphtha.
- Meeting BS IV/BS V Specifications of MS and HSD.
- Maximization of MS and Diesel.
- Fuel Oil Demand as Zero.

1.3.5 Product Demand

The product demand considered for the DFR is as below:

Table 1.1: Product Demand

Sl. No	Product	Minimum (KTPA)	Maximum (KTPA)
1.	Propylene - zone	66	Maximize
2.	LPG - Zone	0	3229
3.	LPG – Out of Zone	0	3229
4.	Naphtha - Zone	0	28
5.	Naphtha – Out of Zone	0	9
6.	Naphtha –Export	0	Minimize
7.	MS BS IV Regular Zone	0	774
8.	MS BS IV Regular Out of Zone	0	375
9.	MS BS IV to MDPL	0	771
10.	MS BS V - Zone	0	202

Sl. No	Product	Minimum (KTPA)	Maximum (KTPA)
11.	MS BS V - Out of Zone	0	203
12.	MS Euro V - Export	0	875
13.	Jet fuel - Zone	29	29
14.	Jet fuel – Out of Zone	1.5	1.5
15.	Kerosene - Zone	448	463
16.	Kerosene – Out of Zone	0	230
17.	Diesel BS IV - Zone	0	3898
18.	Diesel BS IV – Out of Zone	0	2081
19.	Diesel BS IV – via Paradeep to Interior	0	671
20.	Diesel BS V - Zone	0	320
21.	Diesel BS V – Out of Zone	0	624
22.	Diesel BS V – to MDPL	0	1906
23.	LDO - Zone	0	3
24.	LDO – Out of Zone	0	31
25.	LSHS - Zone	0	61
26.	LSHS – Out of Zone	0	261
27.	Fuel Oil – Zone	0	0 (Note-1)
28.	Fuel oil- Out of Zone	0	0
29.	Bitumen -Zone	5	5
30.	Bitumen – Out of Zone	215	463
31.	Sulphur	0	As produced

Note 1: EIL has done a LP run for production of 174 KTPA of fuel oil and provided the details to HPCL.

1.3.6 Feed, Product and Utility Prices

The feed and product are the actual average of last three years (Financial years 2011-2012, 2012-2013, and 2013-2014).

Table 1.2: Feed and Product Prices

	UOM for price	Price
Feed		
Basrah Light	Rs/MT	41677
Doba	Rs/MT	37999
Bonny Light	Rs/MT	46562
Maya	Rs/MT	38229
Arab Extra Light	Rs/MT	46183
Murban	Rs/MT	46513

	UOM for price	Price
Qua Iboe	Rs/MT	46399
Bombay High	Rs/MT	45520
Natural Gas	US\$/MMBTU (Note-1)	20.59
Alkylate	Rs/MT	63424 (Note-2)
Product		
Propylene – Zone	Rs/MT	61012
LPG – Zone/Out of Zone	Rs/MT	51588
Naphtha – Zone/Out of Zone	Rs/MT	50712
Naphtha-Export	Rs/MT	49130
MS BS III	Rs/KL	41459
MS BS IV Regular Zone/Out of Zone/MDPL	Rs/KL	42089
MS BS V – Zone/Out of Zone	Rs/KL	42717
MS Euro V - Export	Rs/KL	42217
Jet fuel - Zone/Out of Zone	Rs/KL	42767
Kerosene - Zone/Out of Zone	Rs/KL	43167
Diesel BS- III	Rs/KL	44793
Diesel BS IV - Zone/Out of Zone/via Paradeep to interior	Rs/KL	44918
Diesel BS V - Zone/Out of zone/MDPL	Rs/KL	45044
LDO – Zone/Out of Zone	Rs/MT	50875
LSHS – Zone/Out of Zone	Rs/MT	38547
Fuel Oil – Zone/Out of Zone	Rs/MT	37503
Bitumen -Zone/Out of Zone	Rs/MT	31128
Sulphur	Rs/MT	5073
SHCU Pitch	Rs/MT	5723

Notes:

1. Natural gas purchase price is 55669 Rs/MT considering Net calorific value of natural gas as 11451 Kcal/Kg and US \$ exchange rate as 1 US \$ = 59.5 INR.
2. Alkylate price is calculated considering 14.1 US\$/bbl higher than Euro IV MS.

Table 1.3: Utility Prices

Utilities	UOM for Price	Price
Raw Water	Rs/m3	35
Sea cooling Water(Recirculating)	Rs/m3	4
Imported Power	Rs/KWH	6.5

1.3.7 Product Specifications

Product specifications as provided by HPCL in the Design basis Section (refer Section no.4 of this DFR) has been followed in the Study. MS and Diesel shall conform to BS IV/BS V quality.

1.4 OPTIMIZATION OF REFINERY CONFIGURATION

Revised material balance and process unit capacities of the selected Refinery configuration of September 2012 VRMP DFR is required to be re-established for revision of capital cost estimate and financial analysis. Hence LP model of the Refinery is updated with revised crude mix and revised feed/product and utility prices.

- MS block capacities (NHT/CCR/ISOM) of Existing Refinery are not adequate to meet the objectives of VRMP. Hence to determine the revamp/new light end processing units' capacities a number of configuration cases are evaluated.
- Revamp of DHDT unit facilitates processing of LCO whereby existing FCCUs throughput capacities were maximised. Thus, distillate yields were maximised.
- New Process Unit's yield and product properties are updated as the feed quality changes due to revision in crude mix.
- For meeting power requirement following three options are considered:
 - Existing 2 GTGs in operation (with naphtha as fuel to GTGs)+ Balance power import
 - Total Captive power plant with naphtha as fuel to GTGs
 - Total Captive power plant with natural gas and naphtha as fuel to GTGs and feed/fuel to Hydrogen Generation Units
- The Coal based power plant which was proposed to be located in the close vicinity of the Refinery could not be taken forward due to the height restriction imposed by Eastern Naval Command (not more than 48 metres in the proposed coal power plant area).

1.5 KEY FINDINGS OF CONFIGURATION STUDY

Following are the key findings of configuration study:

- Naphtha production from Refinery can be made to nil (zero) in both Captive power plant cases and power import case. However in 2 GTGs + balance power import case and natural gas case, additional train of complete MS block (NHT, CCR and ISOM) is required to meet this requirement. This requires additional plot area. Hence it is decided to consider revamp of NHT and CCR to the extent feasible along with meeting objectives of the study.
- Based on feed back from process Licensors, 130% revamp of NHT and 120% revamp of CCR are feasible with minimum shutdown time for implementation. Hence it is decided to consider the same.
- It has been observed that a new naphtha Isomerisation unit is mandatorily required to be installed along with revamp of NHT and CCR. This helps to reduce naphtha make substantially and to increase MS make. Study on whether to consider a new alkylation unit or a new ISOM unit is better to meet BS V MS shows that since the RON requirement of BS V MS is 91, new ISOM unit is preferred over new alkylation unit. Hence it is decided to consider new ISOM unit in VRMP.
- Sulphur reduction in existing FCC Naphtha Hydrotreater Heavy naphtha which is proposed for implementation in Refinery is mandatorily required.
- Both existing FCC units shall continue to process Bonny Light VR along with Vacuum Gas Oil.
- New Propylene Recovery Unit is required to recover the additional potential of propylene from existing FCC units.
- Benzene Heart cut naphtha from FCC NHT unit is considered as feed to new Hydrogen Generation unit. Since there is no other destination of this stream, even in natural gas as an option for feed/fuel to hydrogen generation units, heart cut naphtha shall be routed along with natural gas to HGU. Hence new HGU shall be designed for dual mode of operation.
- In the case with natural gas as fuel for GTGs, the maximum quantity of natural gas that can be utilized is also dependent on the naphtha export quality specifications. In the present case naphtha export pool is limited on minimum paraffin specification of 70 vol% and maximum aromatic specification of 6 vol%. Hence heavy naphtha streams which are having lower paraffin content are not getting accommodated in the

naphtha pool. So excess quantity of heavy naphtha shall be necessarily fired in GTGs along with natural gas.

Based on many LP iterative runs and different case scenarios, the following process configuration has been recommended by EIL along with a New CDU/VDU:

NHT Revamp: 130%+ CCR Revamp: 120%+, ISOM: new +DHDT Revamp: 120% + Full Conversion HCU+ SDA+ Slurry Hydrocracker Unit

1.6 SHORTLISTED CASES FOR FINANCIAL ANALYSIS

Based on the power sourcing scenarios, the following three (3) cases are shortlisted for Capital Cost Estimate and Financial Analysis for the selected process configuration

- Case A: Existing 2 GTGs in operation (with naphtha as fuel to GTGs) + Balance power import
- Case B: Total Captive power plant with naphtha as fuel to GTGs
- Case C: Total Captive power plant with natural gas and naphtha as fuel to GTGs and feed/fuel to Hydrogen Generation Units

1.6.1 Material balance

LP runs for the short listed cases have been done for design crude mix meeting all product specifications as mentioned in design basis.

The material balance for all the three cases along with base case considered for IRR estimation are presented below in the Table-1.6.

Table 1.6: Material Balance for Shortlisted cases (KTPA)

Stream	Base Case	Case A	Case B	Case C
FEED				
Qua Iboe	2778	0	0	0
Murban	1500	0	0	0
Mumbai High	556	0	0	0
Arab Extra Light	1500	0	0	0
Basrah Light	2000	10800	10800	10800
Bonny Light	0	3000	3000	3000
Doba	0	1200	1200	1200
Natural Gas	0	0	0	675
Additive	0	24	24	24
Total Feed	8333	15024	15024	15699
PRODUCT				
Propylene (Chemical Grade)	72	101	101	104
LPG	381	606	602	606
Naphtha	0	215	0	810
MS- BS III	1306	0	0	0
MS- BS IV	354	1750	1730	1752
MS- BS V	0	405	405	405
Total Light Distillates	2113	3077	2838	3677
Light Distillates %	25.4	20.5	18.9	23.4
ATF	67	30.5	30.5	30.5
SKO	174	693	693	693
Diesel-BS III	3875	0	0	0
HSD - BS IV	0	6396	6229	6650
HSD - BS V	0	2626	2850	2430
High Flash Diesel	0	0	0	0
LDO	111	31	31	31
Total Middle Distillates	4227	9776	9834	9835
Middle Distillates %	50.7	65.1	65.5	62.7
Fuel Oil	1081	0	0	0
Bitumen	220	221	221	221
LSHS	139	0	0	0
SHC Pitch	0	242	239	239
Sulphur	29	297	298	298
Total Heavy Distillates	1469	760	758	758
Heavy Distillates %	17.6	5.1	5.1	4.8
Fuel & Loss	524	1415	1596	1423
Fuel & Loss %	6.3	9.4	10.6	9.1
TOTAL Products	8333	15024	15024	15699

1.6.2 Gross Refinery Margin

Gross Refinery Margin (product sales-feed stock purchase) for all the three cases along with base case is provided in Table 1.7 below:

Table 1.7: Gross Refinery Margin for Shortlisted cases

Gross Refinery Margin	Base Case	Case A	Case B	Case C
	Existing Refinery	LP Case 623	LP Case 632	LP Case 645
Rs Crores/Annum	2000	7940	7070.5	7450.7
U S \$/bbl	5.43	12.36	11.01	11.60

1.6.3 Design Capacities of New/Revamp Process Units

Design capacities of new/revamp process units considered is same for all the three cases for Capital cost estimation.

Table 1.8 Design Capacities of New/Revamp Process Units

A.	Main Processing Unit		CAPACITY
1	CDU / VDU	MMTPA	9
2	NAPHTHA ISOMERISATION UNIT	KTPA	292
3	FULL CONVERSION HCU	MMTPA	3.3
4	SOLVENT DEASPHALTING	MMTPA	3.1
5	SLURRY HYDROCRACKER UNIT	MMTPA	2.5
6	PRU	TPD	96
B.	Auxiliary Units		
1	HYDROGEN GENERATION UNIT	KTPA	2 X 113
2	FUEL GAS PSA	KTPA	36
2	SULFUR RECOVERY UNIT	TPD	2 X 360
3	SWS-I	TPH	300
4	SWS-II	TPH	185
5	ARU	TPH	2 X 540
6	SR LPG TREATER	TPA	112000
C.	Existing Units Requiring Revamp		
1.	NHT (existing capacity= 1.154 MMTPA):30% Revamp	MMTPA	0.346
2.	CCR/CCR PSA (existing capacity = 0.769 MMTPA):20% Revamp	MMTPA	0.154
3.	DHDT (existing capacity = 2.2 MMTPA): 20%	MMTPA	0.44

1.7 NEW UTILITY SYSTEMS

Following new Utility systems are considered under VRMP for selected cases.

Table-1.9: New Utility Systems

UTILITY SYSTEM	Case A (2 GTG + Balance Power Import)	Case B and Case C (Total captive Power Plant)
Raw Water System		
BCW Make Up + Service water Pumps	Capacity : 380 m3/hr Number : 1w+1s	Capacity : 380 m3/hr Number : 1w+1s
DM Feed Pumps	Capacity : 480 m3/hr Number : 1w+1s	Capacity : 400 m3/hr Number : 1w+1s
Recirculating Sea Cooling Water System		
Cooling Tower Cells	CT-1 : Capacity : 4000 m3/hr Number : 3w+1s	CT-1 : Capacity : 4000 m3/hr Number : 7w+1s
	CT-2 : Capacity : 4000 m3/hr Number : 7w+1s	CT-2 : Capacity : 4000 m3/hr Number : 7w+1s
Recirculating Sea Cooling Water Pumps	CT-1 : Capacity : 4000 m3/hr Number : 3w+1s	CT-1 : Capacity : 4000 m3/hr Number : 7w+2s
	CT-2 : Capacity : 4000 m3/hr Number : 7w+2s	CT-2 : Capacity : 4000 m3/hr Number : 7w+2s
Bearing Cooling Water System		
Bearing Cooling Tower Cells	Capacity : 800 m3/hr Number : 4w+1s	Capacity : 800 m3/hr Number : 4w+1s
Bearing Cooling Water Pumps	Capacity : 800 m3/hr Number : 4w+1s	Capacity : 800 m3/hr Number : 4w+1s
Demineralised Water System		
RO System	500 m3/hr	500 m3/hr
DM Water Tanks	2 X 4700 m3 capacity.	2 X 4700 m3 capacity.
DM Water Transfer Pumps	Process units: Capacity : 180 m3/hr. Number : 1w+1s	Process units: Capacity : 180 m3/hr. Number : 1w+1s
	Steam Generation: Capacity : 150 m3/hr. Number : 1w+1s	Steam Generation: Capacity : 150 m3/hr. Number : 1w+1s

UTILITY SYSTEM	Case A (2 GTG + Balance Power Import)	Case B and Case C (Total captive Power Plant)
Power Plant Configuration		
CPP	New GTG : NIL	New GTG: 2 Power : 2 X 33 MW Type : Frame VI HRSG : 2 X 110 TPH Pressure : 100 Kg/cm2(g)
	Boiler : Number : 1W+ 1S Design capacity : 190 TPH Pressure : 36 kg/cm2 (g)	Boiler : Number : 1W+ 1S Design capacity : 225 TPH Pressure : 36 kg/cm2 (g)
	Steam Turbine Generator: Number : 1 Type : Double Extraction (VHP to MP & LP) Power : 23 MW	Steam Turbine Generator: Number: 3 1. Type : Double Extraction (VVHP to MP & LP) Power : 33 MW
	Grid Power Import : 155 MW	2. Type : Extraction Cum Condensing (VHP to LP & Condensate) Power : 33 MW 3. Type: Total Condensing (VHP to Condensate) Power : 33 MW
Condensate System		
Condensate Polishing Unit	Capacity: 65 m3/hr Number : 1W + 1S	Capacity: 65 m3/hr Number : 1W + 1S
Compressed Air System (Plant and Instrument Air)		
Air Compressors	Capacity : 13000 Nm3/hr Number : 2W +1S	Capacity : 13000 Nm3/hr Number : 2W +1S
Instrument Air Dryer	Capacity : 7000 Nm3/hr Type : Dual Bed Number : 2	Capacity : 7000 Nm3/hr Type : Dual Bed Number : 2
Emergency Air Compressor	Capacity : 250 NM3/hr Number : 1 Type : Reciprocating	Capacity : 250 NM3/hr Number : 1 Type : Reciprocating

UTILITY SYSTEM	Case A (2 GTG + Balance Power Import)	Case B and Case C (Total captive Power Plant)
LP Air Receiver	Number : 1 Diameter : 2.5m Height : 6.2 m Des Pr : 10.5 Kg/Cm2 g	Number : 1 Diameter : 2.5m Height : 6.2 m Des Pr : 10.5 Kg/Cm2 g
HP Air Receiver	Number : 1 Diameter : 5 m Height : 13 m Des Pr : 34 Kg/Cm2 g	Number : 1 Diameter : 5 m Height : 13 m Des Pr : 34 Kg/Cm2 g
Nitrogen System		
Nitrogen Plant	Gaseous : 1560 Nm3/hr Liquid Storage: 5 X 200 m3	Gaseous : 1560 Nm3/hr Liquid Storage: 5 X 200 m3

Power Balance: Post VRMP

Table- 1.10: Power Balance

	Projects	Case A (2 GTG + Balance Power Import)	Case B and Case C (Total captive Power Plant)
		MW	MW
Requirement	Existing Refinery	90	90
	VRMP	130	135
	Total	220	225
Generation	Existing Refinery	42	63
	VRMP	23	162
	Power Import	155	0
	Total	220	225

1.8 NEW OFFSITE FACILITIES

The offsite facilities shall be augmented by adding the following new storage tanks and pumps in Refinery/ATP Area.

Table- 1.11: List of new Product tanks

Sl. No.	Service	No. of Tanks	Type	Liquid Stored Capacity (m3)
1.	Diesel Tanks	8	Floating	40000
2.	Diesel Tanks	2	Floating	23529

Table 1.12 : List of new crude / product pumps

Sl. No.	Service	No. of pumps	Flow (m3/hr)	TYPE
1.	HS Crude Transfer Pump	1W+1S	1400	Centrifugal
2.	High TAN Crude Transfer Pump	1W+1S	200	Centrifugal
3.	FCC Feed Pump	2 W+1S	200	Centrifugal
4.	SDA Feed Pump	1W+1S	410	Centrifugal
5.	HCU Feed Pump	1W+1S	475	Centrifugal
6.	SHC Feed Pump	1W+1S	365	Centrifugal
7.	Hydrogen Feed Pump	1W+1S	130	Centrifugal
8.	Sour water pump 1	1W+1S	100	Centrifugal
9.	Sour water pump 2	1W+1S	25	Centrifugal

1.9 CAPITAL COST ESTIMATE

Key Assumptions:

The basic assumptions made for working out the capital cost estimate are as under:

- Cost estimate is valid as of 4th Quarter 2014 price basis.
- No provision has been made for any future escalation.
- No provision has been made for any exchange rate variation.
- It has been assumed that all units and utilities / off-sites facilities would be implemented on conventional mode except for HGU &SRU which will be executed on LEPCC mode.
- Process units cost estimates are based on reference technology. Any change in technology shall have impact on unit's cost estimates.
- EPCM/PMC services cost provision is as a factor basis and is indicative.
- All costs are reflected in INR and all foreign costs have been converted into equivalent INR using exchange rate of 1USD=Rs 59.5.
- It has been assumed that existing land, infrastructure facilities and township are adequate for this project.

Exclusions:

Following costs have been excluded from the Project cost estimate:

- Forward escalation
- Exchange rate variation
- Cost towards statutory clearances
- Pipeline/ SPM / COT

As indicated above, the estimated project cost for the identified scope and technical details for the shortlisted cases works out to as under:

Table-1.13: Capital cost (Rs. Crores) of shortlisted cases

S.No.	Cases	Fc	Ic	Total Capital
1	Case A	1603.47	15340.02	16943.50
2	Case B	1636.55	16760.03	18396.58
3	Case C	1636.55	16775.69	18412.24

Case A: Existing 2 GTGs in operation (with naphtha as fuel to GTGs) + Balance power import

Case B: Total Captive power plant with naphtha as fuel to GTGs

Case C: Total Captive power plant with natural gas and naphtha as fuel to GTGs and feed/fuel to Hydrogen Generation Units

Cost estimate is based on cost information available from EIL's current in-house cost data and Engineering inputs for cost estimation purpose. In-house cost data has been analyzed and adopted for estimation after incorporating specific project conditions. Cost data has been updated to prevailing price level using relevant economic indices.

1.10 FINANCIAL ANALYSIS

Based on capital cost, operating cost and sales revenue, financial analysis have been carried out for calculating internal rate of return (IRR) with a view to establish profitability of the project.

Table-1.14: IRR of shortlisted cases

SI No.	Case	Case A	Case B	Case C
1	Capital Cost (Rs. Lakhs)	16943 50	18396 58	18412 24
2	Variable Operating Cost (Rs. Lakhs/ year)	26678 86	25975 57	29733 23
3	Fixed Operating Cost (Rs. Lakhs/ year)	299 30	324 76	324 84
4	Total Operating Cost (Rs. Lakhs/ year)	26978 16	26300 34	30058 07
5	Sales Revenue (Rs. Lakhs/ year)	31863 53	30993 91	35131 75
6	IRR (Pre Tax) on Total Capital (%)	22.89%	20.76%	22.14%
7	IRR (Post Tax) on Total Capital (%)	19.47%	17.75%	18.89%

1.11 ENERGY CONSERVATION EFFORTS

Many state-of-art energy conservation measures outlined in section-8 are being incorporated at the design stage itself in order to minimize the overall energy requirement. Efforts shall be made to bring down the specific energy consumption of the proposed units to meet the global benchmark standards.

1.12 ENVIRONMENTAL IMPACT

In order to minimize the impact of the project on the environment, due attention is being given for implementing effective pollution control measures. The design stage endeavors to mitigate the problems related to health, safety and environment at the process technology/source level itself. The design basis for all process units lays special emphasis on measures to minimize the effluent generation at source.

Liquid effluents

The liquid effluents from Refinery post VRMP will meet the Minimum National Standards as specified under proposed effluent and emission standards for petroleum oil refineries by suitable augmentation of Effluent Treatment Plants. Furthermore in the effort to minimize the effluent generation, system like recirculating cooling water is being considered for the expansion. Also suitable provisions are made to enable maximum recycle and reuse of treated effluent.

Gaseous Emissions

All the emission from the Refinery Complex shall meet the stipulated standards under "PROPOSED EFFLUENT AND EMISSION STANDARDS FOR PETROLEUM OIL REFINERIES".

- The total Sulphur Dioxide emissions from the refinery complex after development of proposed additional units and capacity expansion will not exceed the present limit of 11.5 T/day.
- New Sulfur Recovery Units has been considered with TGT facilities
- Sweet Refinery fuel gas with H₂S=100 ppmw (max.),
- Low sulfur naphtha has been considered in GTGs.
- Low sulphur Fuel oil has been considered for firing in the furnaces.
- Heaters/furnaces will be provided with well-proven Low NO_x burners to restrict the emissions of Nitrogen Oxides (NO_x) to meet the proposed emission standards for Petroleum Oil refineries.

From the above it is evident that there will be no additional impact of gaseous emissions on the environment due to expansion.

Solid Wastes

The solid wastes i.e. Spent Catalysts, ETP Sludge, General Solid Wastes, Tank Bottom Sludge etc. generated in the Refinery shall be minimised by implementing solid waste implementation management plan.

1.13 SOCIAL BENEFITS

The Visakh Refinery Modernization Project in addition to increasing the availability of petroleum products in the region is also expected to generate employment, both direct and indirect.

1.14 RECOMMENDATIONS

Based on the feasibility study it is recommended to consider expansion of HPCL Visakh Refinery from 8.33 MMTPA to 15.0 MMTPA with the following process configuration in VRMP:

- New 9.0 MMTPA CDU/VDU
- New naphtha Isomerisation Unit
- New Full Conversion HCU
- New SDA
- New Slurry Hydrocracker Unit
- NHT Revamp (130%)
- CCR Revamp (120%)
- DHDT Revamp (120%)

The selected configuration has been subjected to the following three cases based on power sourcing.

CASE A : 2 Existing GTGs (in Naphtha) + Balance Power import

Based on the certainty of power available from grid, investments for full captive power generation can be reduced.

This case has an investment of **Rs 16944 Crores with a Post Tax IRR of 19.47%**.

CASE B : Total in house Power Generation (Captive Power with naphtha)

In the case with total captive power generation, the investments are comparatively higher i.e **Rs 18397 Crores** and the **Post Tax IRR is 17.75 %**.

CASE C : Total in house Power Generation (Captive Power in Natural Gas & NG as HGU Feed)

In this case with total captive power generation, natural gas instead of naphtha is considered as fuel in Captive Power Plant. Further, in HGU natural gas is considered as feed instead of naphtha.

This case has an investment of Rs.18412 Crores and the Post Tax IRR is 18.89%. Natural gas is considered at natural gas price of 55669 Rs / MT i.e 20.59 US\$ / MMBTU and corresponding net calorific value as 11451 Kcal/kg.

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- The economic analysis portrays a robust rate of return for all cases.
 - Hence, it is recommended that all the above cases result in a significant return on investment the expansion per se can be taken forward for implementation. As stated above, grid based power availability can be the deciding factor for CPP configuration
 - Considering a self sustained operation, to meet the entire refinery power requirement CPP may be included in the configuration.

7.3 PROCESS DESCRIPTION

7.3.0 INTRODUCTION

A brief process description along with a flow schematic for each of the process units envisaged as part of the shortlisted refinery configurations are provided in this section.

1. Crude/Vacuum Distillation Unit
2. Hydrocracker Unit
3. Slurry hydrocracker unit
4. Solvent deasphalting unit
5. Isomerization Unit
6. Propylene Recovery Unit
7. Hydrogen Generation Unit
8. Sour Water Stripper
9. Sulphur Recovery Unit (With Tail Gas Treatment Unit)
10. LPG Treating Unit
11. Amine Regeneration Unit

Schematic Flow Diagrams for all the above process units are attached in **Annexure-II.**

7.3.1 CRUDE/VACCUM DISTILLATION UNIT

Refer schematic flow diagram no: A638-02-41-00-0011-A

Crude Distillation Unit

Crude Charge and Preheat Train-I

Crude from offsite storage is received at CDU/VDU plant battery limit. The crude is subsequently heated in preheat exchangers by hot streams of CDU/VDU. Crude picks up heat in the preheat exchangers before being routed to Crude desalter.

Desalter

A 2-stage electrostatic Crude Desalter to be provided for removal of salt and water from the crude to desired level. The principle of desalting operation requires mixing of preheated wash water in a mixing valve with the crude under controlled conditions and to extract impurities.

Crude Preheat Train-II and Preflash

The crude from Desalter outlet is routed to the 2nd train of pre heat exchangers. Crude picks up heat from hot streams of CDU/VDU and routed to Preflash drum. The liquid separated in the Preflash drum is pumped to crude preheat train-III.

Crude Preheat Train-III

The pre flashed crude is heated in 3rd preheat train exchangers. Crude picks up heat from hot streams of CDU/VDU and finally routed to crude heater.

Crude Heater

The preheated crude is fed to the crude heater and equally distributed to the heater passes through pass balancer control valve. The total crude flow to the unit signal is sent to the crude throughput controller, which sends signal to the furnace flow controllers.

Crude Distillation Column

Heated and partially vaporised crude enters crude column through feed nozzle. The column has five side draws, namely, Light Naphtha (SN), Heavy Naphtha (HN), Kerosene (Kero), Light Gas Oil (LGO) and Heavy Gas Oil (HGO).

Crude Column Overhead Circuit

The overhead system consists of a two stage condensing system with wash water circulation.

Sour water separated in reflux drum is partly returned as wash water for atmospheric column overhead vapours. All the salt are dissolved in wash water and are purged out of the system through sour water purge stream to sour water stripper unit. Additionally Filming Amine is also injected in the crude column overhead line in order to protect the overhead line.

Light/Heavy Naphtha Section

Naphtha is drawn as side product to side stripper. Stripper is provided with thermosiphon reboiler to knock off light ends from naphtha. The CDU hot stream is used as heating medium in reboiler. The bottom product of light/heavy naphtha stripper is pumped to naphtha product cooler. The cooled product ex-product cooler is finally routed to storage. The light hydrocarbon vapours leaving the naphtha stripper is returned to the crude column.

Kerosene Section

Kerosene product is drawn from crude column. The kero product flows to the kero stripper under stripper level control. Kero stripper is a reboiled stripper using CDU hot stream as reboiling medium. The light hydrocarbon vapours leaving the kero stripper are returned to the crude column.

Light Gas Oil Section

LGO product and LGO CR stream is drawn as a single stream from crude column. One stream as LGO product flows to the LGO Stripper under LGO stripper level control where it is stripped using MP steam under flow control and the stripped vapours are returned back to the Crude Column below.

Heavy Gas Oil Section

HGO product & HGO CR are drawn as a single stream from the Crude Column. One stream as HGO Product flows to the HGO Stripper under stripper level control where it is stripped using MP steam under flow control and stripped vapours are returned back to the Crude Column.

Reduced Crude Oil Section

Stripped RCO from the column bottom is sent to the Vacuum Heater under level control of atmospheric column bottom cascaded with the pass flow controller of Vacuum Heater. MP steam under flow control is introduced as stripping steam of the Crude column.

Crude Column Circulating Refluxes

Crude Column is provided with three Circulating Reflux streams for optimum vapour-liquid internal traffic and heat recovery.

KERO CR:

Kero CR is drawn along with Kero product and is pumped by Kero CR pump. The heat available in Kero CR is removed in crude preheat exchangers.

LGO CR:

LGO CR is drawn along with LGO product and is pumped by LGO CR Pump. The heat available in LGO CR is removed in crude preheat exchangers and reboiler.

HGO CR:

HGO CR is drawn along with HGO product and is pumped by HGO CR Pump. The heat available in HGO CR is removed in crude preheat exchangers and reboiler.

Product Rundown Section

Light/Heavy Naphtha Product Circuit

Light/heavy naphtha from naphtha stripper bottom is pumped by Light naphtha Product pump for heat recovery and then to Naphtha Air cooler followed by naphtha Trim Cooler before sending it for storage.

Kero Product Circuit

Kero product from Kero Stripper bottom is pumped by Kero Product pump. After heat recovery, Kero product is further cooled in product coolers to required rundown temperature and routed to storage.

LGO Product Circuit

LGO Product from LGO Stripper is pumped by LGO product Pump for heat recovery, After Heat Recovery LGO product is further cooled in product coolers to required rundown temperature and routed to storage.

HGO Product Circuit

HGO Product from HGO Stripper is pumped by HGO Product Pump. After heat recovery, HGO product is further cooled in product coolers to required rundown temperature and routed to storage.

RCO Product Circuit

Normally, Reduced Crude Oil (Crude Column residue, RCO) from Crude Column is pumped to vacuum unit with out any cooling. However, provision is kept to cool the hot RCO stream in crude preheat circuit and coolers to facilitate to operate Crude unit alone with out Vacuum unit and route the RCO stream to storage.

Naphtha Stabilizer

Naphtha Stabiliser Column

The unstabilised naphtha consisting of all the fuel gas, LPG and Naphtha components is pumped to Naphtha stabiliser column after preheating in the stabiliser feed/bottom exchanger.

The overhead products are partially condensed in the Stabiliser Overhead Condenser. Fuel gas and LPG are withdrawn from the overhead circuit. Fuel gas is routed to Fuel Gas ATU and LPG is routed to LPG Treater.

Stabiliser column is a reboiled column using CDU hot stream as reboiling medium. Stabilised Naphtha is further cooled in the exchanger to required rundown temperature before routing the same to the storage.

Vacuum Distillation Unit

Vacuum Heater

Hot RCO from Crude column bottom is pumped by RCO pumps to Vacuum heater. Each coil outlet of vacuum heater joins the transfer line and is routed to Vacuum distillation column. The mixed vapour & liquid stream from the heater is introduced to the Flash zone of Vacuum column.

Vacuum Distillation Column

Heated & partially vaporised RCO from Vacuum Heater enters the Vacuum Column. An open ended tangential entry device and a large empty space above flash zone ensure optimal vapour liquid separation.

Stripping section:

The heavy hydrocarbons are stripped on valve trays. Subsequently the residue is quenched by the vacuum residue product (Quench) to prevent after cracking in the

bottom compartment of the column. The various side streams taken out from Vacuum Column are Vacuum Diesel, LVGO, HVGO and Slop Distillate.

Overhead Circuit:

Overhead vapour from vacuum column goes to the vacuum system. The vacuum system is designed with a two stage ejector and a vacuum pump as the third stage. Sour water from Hotwell is pumped by Hotwell Sour water pumps. Sour water ex-Hotwell flows under interphase level-cascaded flow control for further treatment in sour water stripper unit.

Vacuum Diesel Section:

Vacuum Diesel is drawn and pumped by Vacuum Diesel Product + CR + IR Pump and is divided into 2 streams, namely, Vacuum Diesel IR, Vacuum Diesel CR + Product. Vacuum Diesel IR is returned back under flow control to the Vacuum Column. The product stream is cooled in the Vacuum Diesel Product + CR Trim Cooler

Gas Oil Section:

Gas oil is collected in collector tray and pumped by Gas oil IR pumps under level control along with LVGO CR through spray nozzle distributor.

Light Vacuum Gas Oil Section (LVGO):

LVGO from collector tray is pumped by LVGO Product + CR + IR Pump and is divided into 3 streams, namely, LVGO IR, LVGO CR and LVGO product. LVGO IR is returned back under flow control to the Vacuum Column LVGO CR is cooled in crude/LVGO CR Exchanger before returning back to the Vacuum Column along with Gas oil IR.

Heavy Vacuum Gas Oil section (HVGO):

HVGO from Collector tray is pumped by HVGO Product pumps and HVGO CR + IR Pumps HVGO CR+ IR streams are split into two streams namely HVGO CR & HVGO IR. HVGO product after exchanging heat with crude in crude preheats exchangers is combined with LVGO and the combined VGO is cooled in tempered water cooler before being routed to storage.

Wash section:

Slop from bed collector tray flows by gravity to the Slop Drum. Slop from this drum is pumped by Slop Distillate Pump and is divided into 2 streams. Vapours rising from flash zone are condensed by HVGO IR and collected as slop in collector tray. This liquid provides the required washing in this section.

Vacuum Residue Section (VR):

(Vacuum Residue + Quench) from Vacuum Column bottom is pumped by VR + Quench Pump to crude preheat train for heat recovery in Crude/VR+Quench exchangers. The VR + Quench stream is then split into two streams and one stream as VR quench is returned back to the Vacuum Column under flow control cascaded with vacuum column bottom stream temperature controller.

Product Rundown section

Hot well vacuum slop oil:

Hot well vacuum slop oil from Hot well is pumped by hot well Slop Oil Pumps through a coalescer and routed to downstream unit for further processing. Sour water from coalescer is routed to sour water rundown line.

Vacuum diesel Product:

Vacuum Diesel from collector tray is drawn and pumped by Vacuum Diesel Product + CR + IR Pump and is divided into 2 streams namely Vacuum Diesel IR, Vacuum Diesel CR + Product. Hot Diesel stream after heat recovery is routed to DHT and cold stream after cooling to required rundown temperature is sent to the storage.

LVGO Product

LVGO from collector tray is pumped by LVGO Product + CR + IR Pump and is divided into 3 streams namely LVGO IR, LVGO CR and LVGO product. LVGO is combined with HVGO after heat recovery and the combined stream namely Vacuum Gas oil (VGO) is routed to downstream unit. VGO is further cooled in cooler to required rundown temperature before routed to storage.

HVGO Product

HVGO product from Collector tray is pumped by HVGO Pump. Subsequently HVGO is combined with LVGO after heat recovery and the combined stream namely Vacuum Gas oil (VGO) is routed to downstream unit. VGO is further cooled in cooler to required rundown temperature before routed to storage.

Slop distillate product:

Slop from collector tray flows by gravity to the Slop Drum. Slop from this drum is pumped by Slop Distillate Pump and is divided into 2 streams. One stream is returned under flow control back to Vacuum Column as over flash while the second stream as Slop Product is mixed with Vacuum residue.

Vacuum residue product:

(Vacuum Residue + Quench) from Vacuum Column bottom is pumped by VR + Quench Pump to crude preheat train for heat recovery in Crude/VR + Quench exchangers. The VR + Quench stream is then split into two streams. One stream as VR quench is returned back to the Vacuum Column and other stream VR product is routed to residue processing units such as SDA, BBU after heat recovery. VR product is further cooled to required rundown temperature before routed to storage.

Tempered Water System

The cooling of the high pour point products like Vacuum residue & VGO is done by tempered water to prevent exchanger congealing and to reduce exchanger maintenance. Tempered water is pumped from Tempered Water Drum by Tempered Water Pumps to VR/TW cooler and VGO/TW cooler.

Steam Generation Section

Make-up BFW is preheated by VR + Slop rundown stream in VR + Slop/BFW preheater. This make-up BFW then splits into two parts. One of the make-up BFW stream is fed to LP steam drum. The other Make up BFW stream is fed to MP steam drum.

Blowdown

Blowdown from MP steam drum is flashed in a LP flash drum. The flashed condensates from this LP flash drum and blowdown from LP steam drum is sent to Steam Blowdown Drum where it is quenched with service water before draining it to storm sewer.

Chemical Dosing Facility

This system caters to CDU/VDU units.

Demulsifier

Demulsifier chemical is unloaded into demulsifier drums. The drum is provided with a mixer which can be used for preparation of desired concentration levels of the chemical. Demulsifier injection is done at the inlet of First stage desalter.

Filming Amine

Filming amine is unloaded into Filming amine drum. The drum is provided with a mixer, which can be used for preparation of desired concentration levels of the chemical. It is injected in the column overhead circuit to prevent corrosion.

Neutralising Amine

Neutralising Amine chemical is unloaded into Neutralising Amine drum. The drum is provided with a mixer, which can be used for preparation of desired concentration levels of the chemical. It is injected in the column overhead circuit for pH adjustment and to prevent corrosion.

Caustic Solution

Caustic solution is required in the unit for caustic make-up to Vent Gas Caustic Scrubber. 10 wt% caustic solution is obtained from OSBL, which shall be used for make-up in Vent Gas Caustic scrubber. 5 wt% Caustic solution might be required in the unit to be injected into crude line down stream of desalter.

7.3.2 FULL CONVERSION HYDROCRACKER UNIT

Reference is made to schematic flow diagram no: A638-02-41-00-0012 for understanding of this unit.

A Full Conversion Hydrocracker Unit, HCU is proposed to process the VGO from the crude units, DAO from SDA. The Hydrocracker unit shall process the feedstock to produce distillates of required product specifications. The unit is described as follows.

Reaction Section Configuration

Process scheme consists of two stage reactors with recycle. In this configuration, the first stage partially converts the feed blend to diesel and lighter products that are distilled off before the remaining unconverted oil is sent to a second reaction stage. The second stage operates in the absence of ammonia and hydrogen sulfide, i.e., a 'clean' environment. Without the inhibiting effects of ammonia and hydrogen sulfide, the relevant kinetic rate constants in the relatively clean environment, as in the second stage reactor, are much higher than in the first stage. Thus, the second stage operates at lower temperatures, which greatly favors aromatic saturation and reduces hydrocracking to light-ends and naphtha, resulting in improved selectivity towards middle distillates and better product qualities. Because of the reduced level of hydrocracking to light ends, hydrogen consumption efficiency is dramatically improved with most of the hydrogen being utilized for improving the distillate quality.

Hydrocracking involves exothermic cracking and saturation reactions that result in a large heat release, which increases the temperature of the reactants. This increased temperature further increases the rate of reaction. In order to control this temperature rise, the catalyst is separated into various beds so that recycle gas may be introduced between beds to quench the reacting fluids. Reactor internals between the catalyst beds are designed to ensure thorough mixing of the reactants with the quench gas and good distribution of the vapor and liquid flowing down to the next bed. Good distribution of the reactants across the catalyst bed prevents hot spots and maximizes catalyst performance and life.

Recycle Gas Section

A HP amine scrubbing facility will be required to remove H₂S from recycle gas. Removal of H₂S effectively increases the hydrogen partial pressure and increases the hydrogenation rate of aromatic compounds. In addition, high H₂S concentration in the recycle gas adversely affects the second-stage catalyst activity.

Treated gas flows through the recycle gas compressor knockout (KO) drum to remove any entrained amine mist and thus protects the recycle compressor from any entrained liquid in the gas stream. The recycle gas stream then goes to the recycle gas compressor. Part of the recycle compressor discharge gas is routed to the reactors as quench to control the reactor temperature. The remaining recycle gas is combined with hydrogen from the make-up hydrogen compressors to form reactor feed. The reactor feed gas splits with part of the gas going to the first-stage reactor and the remaining gas is sent to the second stage.

Separator Drums

Classical 4 drum configuration consisting of Hot High pressure Separator, Cold High Pressure Separator, Hot Low Pressure Separator & Cold Low pressure Separator has been considered. This configuration allows better heat integration between Reactor effluents and feed preheat thus effectively leading to a reduction in Fuel firing in reactor charge furnace.

Fractionation Section

The Fractionation Section is designed to separate the liquid products from the reaction section and produce diesel as the primary products.

The product stripper, product fractionator and two side cut strippers in the fractionation section are designed to separate the liquid into the desired products, meeting the required product specifications.

The liquid products from the HLPS and the CLPS are fed to product stripper. The purpose of the product stripper is to remove H₂S and stabilize the low pressure

separator liquids. Steam is used at the bottom of the product stripper to improve H₂S and light ends removal. The overhead from the product stripper, consisting of a mixture of water, light gases, LPG, and light naphtha, is sent to the product stripper reflux drum. The reflux drum gases are sent to the Light end recovery section for further processing. The hydrocarbon liquid is pumped by the product stripper reflux pumps and sent back either to the product stripper as reflux or to the LER section. The stripper bottoms feeds to the product fractionator, Overhead vapor from Main Fractionator is totally condensed, liquid is sent to the fractionator reflux drum. The reflux drum hydrocarbon liquid is pumped by the fractionator reflux pumps and routed either back to the product fractionator as reflux or to the LER section. A liquid draw taken off of a collector tray is split between jet pumparound liquid and feed to the jet stripper. The stripper overhead vapor is returned to the product fractionator. The jet stripper bottoms product is pumped by the jet product pumps, cooled by the jet product air cooler and sent to offsite storage. A liquid draw taken off of a collector tray is split between diesel pump around liquid and feed to the diesel stripper.

The diesel stripper bottoms product is pumped by the diesel product pumps, cooled by the diesel product air cooler before it is sent offsite to storage. Steam is used to improve diesel recovery from the UCO. The fractionator bottoms product (UCO) is pumped by the fractionator bottoms pumps and it returns to the reaction section as feed for the second stage.

Light Ends Recovery Section

The main feeds to the LER section are overhead offgas and unstabilized naphtha from the product stripper reflux drum and heavy naphtha from the fractionator reflux drum. Unstabilized light naphtha from the product stripper reflux drum is mixed with lean oil from the lean oil absorber and column overhead from the deethanizer and overhead offgas from the product stripper reflux drum before being cooled.

The cooled mixture then flows to the deethanizer reflux drum. Vapor is sent to the lean oil absorber, the sour water is taken to the sour water degasser, and the hydrocarbon stream then pumped by the deethanizer reflux pumps and fed to the deethanizer at the top of the column as reflux. In the Absorber, lean oil is contacted with the overhead vapor stream from the deethanizer reflux drum remove C3 and heavier molecules from the sour gas. The liquid is pumped by the absorber bottoms pumps and mixes with the unstabilized light naphtha from the product stripper. The overhead vapor from Absorber mixes with lean oil from the naphtha splitter and then flows to the lean oil absorber reflux drum. The overhead from lean oil absorber reflux drum is sent offplot as sour fuel gas, Bottoms is pumped by absorber reflux pumps and returned to Column. The bottom product from deethanizer mixes with heated overhead naphtha from the product fractionator.

The mixture then enters the debutanizer; hydrocarbon stream from Debutanizer is pumped by the debutanizer reflux pumps and is sent either to the column as reflux, or as sour LPG to the LPG treating section for propane and butane recovery and sweetening. The debutanizer bottoms feed the naphtha splitter. Overhead vapor from naphtha splitter is condensed and enters the naphtha splitter reflux drum. The hydrocarbon stream is pumped by the naphtha splitter reflux pumps and is either sent to as reflux or cooled in the light naphtha product cooler) before being sent through sulfur absorbers to remove any residual H₂S and mercaptans compounds.

The liquid is then sent to offplot storage as light naphtha product. The naphtha splitter bottoms liquid is pumped through the heavy naphtha pumps and split into two streams, Part of the bottoms liquid is recycled as lean oil in the lean oil absorber. The remaining liquid flows through the sulfur absorbers to remove any residual H₂S and mercaptans compounds.

The liquid is then cooled by before flowing to off plot storage as heavy naphtha product.

LPG Treating Section

The main feeds to the LPG treating section are sour LPG from the LER section, lean amine from the recycle gas section, and make-up caustic from off plot. The sweet LPG stream is combined with a caustic recirculation stream. The LPG/caustic stream phases are separated in the caustic washer drum, aqueous phase is recirculated by the caustic washer circulation pumps. About once per month, spent caustic is withdrawn from the caustic washer and sent to the caustic degasser. The spent caustic is pumped to off plot treating by the degassed caustic pumps. Make-up caustic from off plot is pumped by the make-up caustic pumps into the caustic washer drum to replace the spent caustic. Treated LPG flows from the caustic washer drum to the water washer drum to remove any entrained caustic. The vessel is water-packed, and LPG flows in droplets up through the continuous water phase. The water removes caustic from the LPG. Treated LPG flows to offsite storage.

Make-Up Hydrogen Section

Make-up hydrogen entering the compression section will come from offplot hydrogen. The make-up hydrogen is supplied to the make-up hydrogen section at 45°C and 20 kg/cm² g. The make-up hydrogen is combined with spillback gas from the first stage of the compressor before going to the common make-up hydrogen first-stage suction drum where any entrained liquid is separated from the gas. After leaving the suction drum, the gas is sent to one of the parallel compressor trains. During normal operation, one train will be used to supply the hydrogen required by the HCR. The second train is a spare.

Products coming out of Fractionation section are: Light Naphtha, Heavy Naphtha, Kero, and Diesel.

7.3.3 SLURRY HYDROCRACKING UNIT

The typical scheme for SHCU unit is shown in schematic flow diagram no A638-02-41-00-0013.

Purpose of SHCU is to process vacuum residue and other heavy residue feedstock into higher-valued distillable products.

Feed Preparation

About 10% of the feed stream and the additive is routed to the Additive Mixing Drum where the pressure is maintained by hydrogen blanketing. The Feed/Additive mixture is then pumped for injection in to inlet of each pass of the Feed Heater.

The remaining 90% of the feed stream is routed to the Feed Surge Drum where the pressure is again maintained by hydrogen blanketing. The Feed Pumps take suction off the Feed Surge Drum and pumps the slurry feed to the required reactor pressure.

Reactor Section:

The feed for each preheat train pass is mixed individually with warm treat gas and is partially preheated against the reactor effluent in the Reactor Effluent / Fresh Feed Exchangers and Fresh Feed / Hot Separator Vapor Exchangers. The combined mixed feed streams are sent to a multiple pass furnace Feed Heater where it is mixed with the additive slurry and further heated to the required reactor inlet temperature. The furnace effluent streams from each of the passes are combined and sent to the Reactors. The reactions involved are exothermic, causing a temperature rise across each reactor. Make up gas from Compressor Package along with recycle gas from Recycle Gas Compressor is injected as quench to each of the reactor vessels to control the average reaction temperature and to limit the outlet reactor temperatures.

The hot reactor effluent flows to the Hot High Pressure Separator Drum where the vapor and slurry liquid phase are separated. The vapor from the bulk separator is sent to a direct coupled cyclone in the second stage separator to remove any entrained aerosols.

Vacuum Distillation

The slurry liquid phase from the two separators contains the unconverted residue, the spent additive and a small quantity of distillates. The liquids are withdrawn on level control and after a low pressure flash sent to the Vacuum

Section of the process to recover any VGO material present in the slurry. The liquid phase from hot separator is flashed to the Hot Low Pressure Separator conditions. The hot flashed vapors are cooled in HLPS Vapor Air Cooler and condensates are separated in Cold Low Pressure Separator. The condensed hydrocarbons from the separators are routed to the Vacuum column. The LP flash gas is routed to LP Amine Absorber through the LP Amine Absorber Feed Knockout Drum.

The vapors in the vacuum column are condensed in two grid beds in the upper section of the column. The condensed VGO is drawn from the chimney tray and is routed to VGO Recycle Pump. The two grid beds are cooled with VGO pump around, which is pumped and cooled in the Vacuum Column Pump around Cooler.

The unconverted residue product from the vacuum column bottom is cooled and sent to OSBL for disposal.

The vacuum tower is equipped with a steam ejector system which maintains vacuum by ejecting out the non-condensable. The vapor from vacuum system is routed to the Vacuum Column Overhead Drum. From this separator, sour water is sent to the battery limit and any slop oil produced is sent to the slop system or recycled to other parts of the process. Vacuum off Gas from the Ejector Condensate Vessel is sent to Furnace fire box.

The vapor from the Hot separator is cooled against the combined feed prior to being fed to the 2nd stage Reactor. The 2nd stage Reactor contains 4 beds of high activity Ni-Mo catalyst and can be tailored to achieve the desired quantity and quality of products. The reactions involved are exothermic, causing a temperature rise across each catalyst bed. Cold recycle gas from the Recycle Gas Compressor is injected as quench between catalyst beds to control the average catalyst temperatures and to limit bed outlet temperatures. The weighted average bed temperatures determine the extent of hydrotreating or hydrocracking reactions. The catalyst beds are separated by quench zone internals to provide outstanding feed distribution and temperature control.

The hot 2nd Reactor effluent is first cooled against the combined feed and then in the 2nd Reactor Effluent Steam Generator to an intermediate temperature and flows to the Hot High Pressure Separator Drum for vapor-liquid separation. Vapor from the separator is cooled against treat gas followed by air cooling and water cooling before flowing into the Cold High Pressure Separator Drum. Wash water is injected continuously upstream of the Hot High Pressure Separator Vapor Air Cooler to aid in the removal of ammonium salts.

The 2nd reactor Cold High Pressure Separator performs a three-phase separation, where the aqueous phase is removed to the sour water system on level control. The sour water is first flashed in the LP flash drum floating on the LP Amine Absorber pressure conditions, before being transported to the sour water stripping unit located offsite.

Hydrogen Purification and Recycle

The recycle gas is sent to the HP Amine Absorber Knockout Drum to remove any entrained hydrocarbon liquid and then routed to HP Amine Absorber. A suitable amine (MDEA) is used as the lean amine in the Absorber. A part of this treated gas is purged to a membrane purification unit to maintain minimum recycle gas purity. The H₂ rich gas from the membrane system is then routed to the inter-stage of the Makeup Gas Compressor package. The remaining treated gas is compressed in the Recycle Gas Compressor and distributed as quench gas in the 2nd Reactor.

Hydrogen Makeup

As the reactions consume hydrogen, make-up hydrogen is brought in from OSBL to maintain the reactor loop pressure. High purity hydrogen (>99%vol) is used as make-up gas. The make-up gas header pressure is assumed to be controlled by the supplier at source. The make-up gas is compressed in a four-stage lubricated reciprocating compressor with inter-cooling and is the source of make-up gas supply to the reactors. Three 50% machines, two operating and one spare are specified.

Hydrocarbon liquids from both the hot and cold HP separators are flashed in LP separators to remove soluble hydrogen. The vapor from the Hot Low Pressure Separator is cooled against Cold Low Pressure Separator liquid followed by air cooling before flowing into Cold LP Separator. The hydrogen rich vapor stream is then routed to the LP Amine Contactor.

Product Fractionation

Liquids from the 2nd reactor Hot and Cold Low Pressure Separators flow to the fractionation section and is fed to the Product Stripper. Vapor from the top tray is condensed in the Stripper Overhead Air Cooler and Trim Cooler and flows into the Stripper Overhead Accumulator, where the water and hydrocarbon liquids are separated. The hydrocarbon liquid stream is refluxed. The low pressure vapors from all the LP flash drums in the unit are combined and sweetened in the common Stripper Off gas LP Amine Absorber and exits the battery limits. The sour water withdrawn from the overhead drum is recycled to the wash water system for use as wash water in the High Pressure Loop.

The Product Stripper bottoms are preheated against the Diesel Pump around, followed by the Fractionator Feed / Bottoms exchanger, and the Fractionator Feed Heater prior to being fed to the Fractionator column.

The fractionator column is designed to fractionate the stripper bottoms stream into a top naphtha product, a side draw diesel product and a bottom VGO product stream. A small quantity of stripping steam is used to assist in the fractionation.

The overhead vapors from the Fractionator column are totally condensed in the Fractionator Overhead Condenser and the condensed liquid product stream is routed to the Fractionator Overhead Accumulator. A portion of the hydrocarbon liquid phase is returned to the Fractionator as reflux and the balance is drawn as stabilized naphtha product and cooled by water before sending to the battery limit. The condensed aqueous phase (water) is recycled to the wash water drum system for use as wash water in the high pressure loop.

A Diesel pump around allows for efficient heat recovery from the Fractionator system by heating the fractionator feed, while minimizing the size of the overhead condenser.

The VGO product is removed from the fractionator bottoms and pumped to the FCC unit after heat recovery in the Side Stream Stripper reboiler and the Feed/Bottoms exchanger prior to being routed as hot feed to the conversion unit. The Diesel product is removed as a liquid side draw, stripped in the Diesel Side Stream Stripper, pumped, cooled in the Diesel Product/CLPS Exchanger, and air cooler prior to being sent to storage.

Amine System

The stand alone amine system for the second stage Hydrotreater will be normally designed to use a 40% MDEA circulating amine with a lean loading of <0.01 mole Acid Gas/Mole of MDEA and a rich loading of 0.4 moles of acid gas/mole of MDEA. The high pressure rich amine from the HP Amine Absorber is re-flashed in the LP Amine absorber to ensure that any flashed out dissolved hydrocarbons are directed to the fuel gas system and the H₂S is re-captured in the amine system. The LP Amine absorber also scrubs the vent vapor stream from the SW Flash drum. The net rich amine stream from the LP Amine Absorber is directed to the amine regeneration unit.

Slurry Pitch Disposal

Slurry pitch which is residual material from the SHCU, is a high energy content pitch having residual iron material and feedstock metals. Slurry pitch generation is in viscous liquid form which can be solidified and can be converted into the transportable granules. Slurry pitch can be considered as economical Alternative fuel because of its controlled properties and ease of bulk handling. There are various value upgrading options for slurry pitch. The options where Slurry pitch can be utilised, are as follows:

Cement Industry: Slurry pitch in the form of solid can be co-fired with coal at up to 30wt% of the fuel requirement in the cement kilns. Since India has a large

demand for low fuel source for its relatively large Cement industry, this market should be an attractive option for slurry pitch utilisation.

Circulating Fluid Bed (CFB) Boilers: There is another option for utilization of slurry pitch as a fuel in CFB boilers. CFB technology has been widely accepted over the last 20 years for high sulphur fuels. CFB boilers have proven ability to handle high sulphur residues and both solid and liquid feeds at wide variations of throughput. CFB ash contains a mixture of calcium sulphate and oxides and is categorized as a weak cement material and can be used as soil stabilizer and for civil engineering purposes.

Conventional Boiler with Electrostatic Precipitator: Slurry pitch can be successfully burned in conventional boiler with an Electrostatic precipitator. This system will require gas desulfurizer for sulphur reduction and NO_x abatement system.

Conventional Boiler with Ammonia Wet Flue Gas Desulfurization to produce Saleable Ammonium Sulphate Fertilizer: Conventional boilers which will use Slurry pitch as fuel will produce high sulphur flue gases. High sulphur flue gases will be treated in wet scrubber with ammonia solution to produce ammonium sulphate. The solution can be crystallized and sales grade ammonium sulphate fertilizer can be manufacture in either granular or standard (crystal) form. This system requires an ESP to lower the ppm level of particulars before the scrubber to maintain good quality in the final fertilizer product.

Slurry Pitch Gasification: Slurry pitch similar to other heavy residues may be gasified in partial oxidation (POX) systems with water gas shift of the synthesis gas with the objective of producing hydrogen in a refinery complex. Gasification of pitch has a relatively high installed cost, but has the advantage of a continuous non- interrupted feedstock at neat zero cost.

Blending of slurry pitch with Bitumen is under study which will facilitate the utilisation of slurry pitch in the form of Bitumen.

7.3.4 SOLVENT DEASPHALTING UNIT

The typical scheme for Solvent Deasphalting unit is shown in schematic flow diagram no A638-02-41-00-0014.

Purpose of this process is to produce deasphalted oil (bright stock) from vacuum residues for further processing in downstream units (HCU/FCC).

Feed stock is cooled to extraction temperature and counter currently treated with propane (as solvent) in an extraction tower. Steam coils near the top of the extractor control the temperature gradient, thus providing reflux and maximum selectivity of separation. Deasphalted oil containing most of alkanes is withdrawn from the top. The major portion of the solvent is evaporated from the oil under pressure and remaining solvent is steam stripped off the oil under vacuum. The asphalt from the bottom of the extraction tower is heated under pressure to recover the solvent and then steam stripped for removal of solvent traces. After recovering the solvent from the asphalt, asphalt is sent to the slurry hydrocracker unit for further processing.

7.3.5 ISOMERIZATION UNIT

The typical scheme for ISOM unit is shown in schematic flow diagram no A638-02-41-00-0015.

The fresh C5 /C6 feed is combined with make-up and re-cycle hydrogen which is directed to a charge heater, where the reactants are heated to reaction temperature. The heated combined feed is then sent to the reactor. Either one or two reactors can be used in series, depending on the specific application. The reactor effluent is cooled and sent to a product separator where the recycle hydrogen is separated from the other products. Recovered recycle hydrogen is directed to the recycle compressor and back to the reactor section. Liquid product is sent to a stabilizer column where light ends and any dissolved hydrogen are removed. The stabilized isomerate product can be sent directly to gasoline blending.

7.3.6 PROPYLENE RECOVERY UNIT (Chemical Grade)

The typical scheme for Propylene Recovery unit is shown in schematic flow diagram no A638-02-41-00-0016.

Cracked LPG is obtained from the two operating Fluid Catalytic Cracking Units (FCCU) in the refinery. Cracked LPG stream is a mixture of propane, propylene, butane and butylenes with some amount of C2 and C5 hydrocarbons.

This is treated in the Cracked LPG treater before being routed to PRU for recovery of propylene.

The treated stream from Cracked LPG Treater is routed through a Caustic Setter where entrained caustic is settled and then routed through a Sand Filter which acts as a coalescer to remove the fine entrained caustic particles. The treated LPG stream is then routed to the Feed surge drum through the feed booster pump.

The pressure of the feed surge drum is set so that it is higher than the vapor pressure of the feed stream. The pressure of the feed surge drum is maintained by split range control opening either to fuel gas or allowing vapors of C3-C4 splitter reflux drum to sustain the set pressure.

Cracked LPG from the feed surge drum is pumped by feed pumps to the C3-C4 splitter column through the feed / bottom exchanger under flow control cascaded by feed surge drum level control. The overhead product (C3, C3=) is cooled in the overhead condenser and routed to the reflux drum. Column pressure is controlled by pressure control valve located between the condenser and the reflux drum. The reflux flow is maintained by flow controller cascaded with temperature controller.

The bottom product from column C3-C4 splitter column which is the lean LPG exchanges heat with the feed and is then cooled to 40°C in the product cooler and routed to the LPG pool under column bottom level control.

The overhead product from column C3-C4 splitter column reflux drum is pumped to C3-C3= splitter column, under flow control cascaded with level control of reflux drum.

The column overhead is condensed in the condenser and routed to the reflux drum. The column pressure is maintained by the pressure control valve located between the condenser and the reflux drum. The reflux is pumped back to the column by the reflux pump. The propylene product is withdrawn by a separate pump.

The C3= splitter column bottom product is cooled in a product cooler to 40°C. The cooled stream is mixed with the bottom stream from column C-01 and together routed to LPG storage as lean LPG.

The propylene product is pumped by product pumps to the chemical treatment system. The chemical treatment system removes impurities like H₂S, Mercaptan and COS. A 15% solution of caustic and monoethanol amine is circulated in the COS settler. Necessary pressure drop is given across the mixing valve which is located upstream of the COS settler in a combined line of propylene and caustic / MEA solution. MEA absorbs COS and caustic eliminates H₂S and mercaptans. The chemical solution is kept circulating by chemical circulation pump. These spent chemicals are blown out via blow down drum. The lost chemicals are made up by chemical dosing pump. Storage vessels of small capacities are provided for storing DM water, caustic and MEA within the unit.

The propylene after chemical treatment is bubbled through a water wash drum. The propylene stream leaving water wash drum will have carry over water. The free water and part of the saturated water is removed in the product coalescer and finally routed to the dryer where the water content of the outlet stream is 15 ppm (max). Propylene is then routed to storage.

The Drying unit consists of two absorber vessels, one of which operates in adsorption phase and the other in regeneration phase. Molecular sieves are used

for adsorption of moisture from the C3 product stream. The adsorption bed is regenerated in closed circuit with nitrogen as the regeneration fluid.

The operating sequence for the absorber vessel consists of an adsorption period, followed by heating and cooling for regeneration. During adsorption, the desiccant displays its affinity for water by removing the saturation moisture from the liquid C3 product stream. Removal of adsorbed moisture from the bed is effected by heating the desiccant bed by convection with hot N₂ and sweeping out the released water vapour from the bed. Cooling the desiccant bed back to near ambient temperature completes reactivation. Continuity of flow is obtained by operating two desiccant towers, one adsorbing while the other is being reactivated.

The regeneration cycle consists of following six steps:

a) Flushing out liquid C3:

The liquid C3 = product shall be flushed out from the Adsorber in standby mode by vaporizing a part of the feed through a steam heated gasifier and flushing out the HC from top to bottom with the vaporized feed and the flushed C3 product shall join the hydrocarbon feed to the bed in adsorption mode.

b) Depressurisation of standby Adsorber:

The standby Adsorber shall be isolated closing all inlet and outlet valves and then depressurized to flare from top by opening the depressurisation valve.

c) Purging HC with nitrogen:

The standby adsorber shall be purged with nitrogen from bottom to top to purge the residual HC into the flare header.

d) Regeneration with hot Nitrogen:

Nitrogen stream shall join the suction of the blower and shall be circulated through the standby adsorber from top to bottom. Nitrogen electric heater shall be brought in line after starting the blower. The nitrogen temperature shall be raised to a sufficient level to drive out the moisture. The moisture laden nitrogen shall be cooled in water cooler to condense the water at

40°C. The water shall then be knocked off in moisture separator and nitrogen shall be circulated back to the suction of the blower. This operation shall be continued till all water is removed.

e) Cooling with Nitrogen:

The electric heater shall be put off and the bypass line of the electric heater shall be brought on line. The blower, water cooler, Moisture separator shall stay on line till the bed is cooled to 40°C.

f) Reinduction of regenerated bed:

The regenerated adsorber shall be brought on line by filling up the HC feed from the bottom and purging out the nitrogen to the flare header.

The dried liquid C3 product is then routed to storage.

HPCL Visakh Refinery is having existing Propylene Recovery Unit to produce 216 TPD of 95 wt% pure chemical grade propylene.

- As per the VRMP DFR Revision LP runs, total propylene production is in the range of 312 TPD. In this case FCC-I & II operating capacities are as below:

FCC-I operating capacity is 2850 TPD (100% % of design capacity)

FCC-II operating capacity is 2598 TPD (~86% of design capacity)

Based on the above new PRU capacity is 96 TPD. This capacity is ~ 30 % of existing PRU capacity. So a new PRU is proposed.

7.3.7 HYDROGEN GENERATION UNIT

The typical scheme for Hydrogen Generation unit is shown in schematic flow diagram no A638-02-41-00-0017.

The hydrogen plant can be divided into two discrete plant sections. The first is referred to as the “front-end” and comprises all the necessary process steps to generate a hydrocarbon feed stream suitable in terms of chemical quality, pressure and temperature for the downstream plant section. The downstream plant section is commonly referred to as “back-end”. The front and back end are

divided by the hydrocarbon feed valve where the ratio of steam and hydrocarbon feed is controlled.

Feed Desulphurization

To ensure adequate pressure drop for the control valve feeding the reformer, the pressure in the front-end is controlled at the location where the (various) feeds and hydrogen are blended at 33.9 barg. Naphtha from BL is sent under level control to the Naphtha Feed Surge Drum. To avoid air ingress the pressure is maintained above 0.5 barg by nitrogen blanketing. The feed is then pumped by the Naphtha Feed Pumps into the process. The hydrogen required for the desulphurization reactions is added in ratio to the feed streams. The actual catalyst design parameter is the molar ratio, to be maintained at: • 0.15 mole H₂ to mole LPG • 0.50 mole H₂ to mole Heavy Naphtha

The actual controlled mass ratio is to be set by the operator based on analysis of the feed stream (Molecular weight). The typical resulting mass ratio is 0.01 kg/kg. The hydrogen used is a slip stream from the hydrogen produced from the PSA unit. The hydrogen is compressed by the Recycle Hydrogen Compressors. The feed/hydrogen mixture is vaporized against saturated/superheated steam to around 300 °C in the Feed Pre-heater / Vaporizer and the Feed Superheater I before superheating in the Feed Superheater II. The superheated feed at about 370 °C passes through the Hydrogenation Reactor and the Desulphurization Reactors arranged in lead-lag configuration.

Reforming:

The desulphurized feed is mixed with process steam under ratio control. The required steam to feed ratio is set by the catalyst in the unit and is chemically defined by the molar ratio of steam to carbon contained in the feed stream (“Steam to carbon ratio”). Since this ratio cannot be measured in the plant, the actual controlled parameter is the mass ratio of steam to total feed that is set for all feeds to 3.5 (“Steam to feed ratio”). This ratio is maintained for capacities down to 50%

of the normal feed rate to the reformer. At lower turndown ratio's the feed rate will be further reduced but the steam rate will be maintained constant resulting in an increasing steam to feed ratio. The hydrogen generation unit design is based on catalytic reforming and pressure swing adsorption (PSA) system is to produce 99.9 mol% pure hydrogen gas. The capacity of the hydrogen generation unit is 2*113 KTPA.

Hydrogen is produced by steam reforming of naphtha. Naphtha from surge drum is pumped to vaporizer. Vaporised naphtha after mixing with recycled hydrogen and superheated steam enters the reformer furnace. Superheated steam is again added at the outlet of pre-reformer to adjust the steam - carbon ratio, and the mixture is heated. The superheated feed steam mixture is distributed through multi tubular reactor consisting of high alloy reformer tubes containing nickel based catalyst. To carry out the reactions producing CO, CO₂ and H₂, heat is supplied by a number of burners burning PSA purge gas and naphtha.

The reformed gas after being cooled undergoes shift conversion in shift converters. These are cylindrical fixed bed reactors containing iron/ chromium oxide or copper/zinc oxide catalyst. Shift conversion reaction converts most of CO into CO₂ and H₂ in presence of the catalyst. The heat removed from the converted process gas is used to vaporize and further heat the feed, and preheat boiler feed water and demineralised water (make up).

Hydrogen is purified to remove inert gas impurities like CO₂, CO, CH₄, N₂ and water vapor by high pressure adsorption of these impurities on molecular sieves, active carbon and alumina gel in pressure swing adsorption (PSA) system. All adsorbed gases are removed during desorption and regeneration of beds and used as reformer fuel. Desorption is done at low pressure and purge gas is used as fuel.

The prereformer utilizes excess heat from the reformer flue gases thereby reducing the heat load on the reformer and improving the heat recovery, both resulting in a reduced steam generation rate. In the pre-reformer all higher hydrocarbons will be

converted to a methane, carbon monoxide, carbon dioxide, hydrogen and steam. The selected reformer catalyst can therefore be "natural gas reforming catalyst" for all feeds. Further the pre reformed gas will reduce the risk of carbon formation in the reformer and thereby allow operating at increased heat flux and increased feed superheat temperature. The chemically defined steam to feed ratio is the mass ratio that can be directly controlled at the desired 3.0 ratio. This ratio is maintained constant throughout the plant capacity range. This implies that at capacities below 50% more and more steam will be bypassing the pre reformer. To maintain the bypass line warm throughout the entire capacity range, the overall steam to feed ratio is always selected higher than the pre reformer steam to feed ratio.

The feed / steam mixture to the Pre reformer is preheated to 450°C in the Feed / Steam Preheater. The process gas leaves the pre reformer at 530°C and is mixed with additional process steam before it is further heated to 630°C in the Feed / Steam Super heater. The superheated feed / steam mixture is evenly distributed over the reformer tubes filled with nickel-based catalyst, in which the reforming reactions take place. The outlet temperature is controlled in cascade where the reformer outlet temperature controller provides the set point for the flue gas temperature controller. This control is selected due to the superior response time.

Reformer Heat Supply and Flue Gas Heat Recovery

The heat required for the reforming reactions in the steam reformer, is supplied by the combustion of the PSA purge gas, supplemented by Naphtha as make-up fuel. The maximum pressure of the PSA purge gas is 0.2 barg at the burner tip whereas the maximum pressure of the make-up fuel is at 2.0 barg at the burner tip. The Naphtha fuel is vaporized against saturated steam and passes through the Fuel Gas K.O. Drum and then superheated against saturated steam to about 200 °C to avoid liquid entering the burners. Dust contained in the fuel naphtha gas is removed in the Fuel Gas Filter to avoid plugging of the burner tips.

During full load operation the PSA purge gas provides the major amount of heat to the furnace. When the PSA unit is not in operation the typical sustainable heat load

on the furnace is 50% of the normal heat load resulting in typical 40% plant capacity. Since the maximum heat load of the make-up fuel is much larger than the normal requirement (in combined firing) the normal make-up fuel pressure at the burner is well below the maximum pressure.

The combustion air is boosted in pressure by the Combustion Air Fan. After preheating to around 500°C in the dual stage air pre-heater, the air is delivered to the burners. The draft in the reformer box is maintained by the Flue Gas Fan. The excess air is controlled by the air to fuel ratio controller. The calculated air rate required can be increased with a factor set by the DCS system based on the oxygen content in the cross-over as measured by the online oxygen analyzer. The excess air at 100% plant load is controlled at 10%.

The heat from the flue gas leaving the radiant section is recovered in the convection section by the following sequence of coils:

- Shock Boiler
- Feed / Steam Super heater
- Feed / Steam Preheater
- Steam Super heater
- Feed Super heater II
- Combustion Air Preheater Hot Stage
- Flue Gas Boiler
- Combustion Air Preheater Cold Stage

The flue gas is discharged at a temperature of approx 150°C to the atmosphere via the Stack.

Steam generation

The major portion of the process steam is produced by cooling of flue gas in the Shock Boiler and the Flue Gas boiler. The boiler water is fed to the steam generating equipment by natural circulation. The generated steam leaves the

Steam Drum at 36 barg. The process steam is superheated to 370°C by process gas in the Steam Preheater. Pressure and capacity are controlled with the process steam valve.

Export steam is produced by cooling the reformer effluent in the Process Gas Boiler. The boiler water is fed to the steam generating equipment by natural circulation. The generated steam leaves the Steam Drum at 43 barg. The export steam is superheated to 380°C against flue gas in the Steam Superheater. The high quality steam is generated at a higher pressure than the process steam to avoid leakage from the process system into the clean system. Pressure and capacity are controlled with the high quality export steam valve. A part of the high quality steam is used as make-up process steam to meet the required steam to carbon ratio in the process gas. The amount of high quality steam to the process is under capacity control of the steam to feed ratio controller.

Steam conditioning

To maintain an acceptable level of contaminants in the boiler feed water, part of the boiler feed water is continuously blown down (3% and 1% of the BFW flow to the process and export steam drum respectively). The blow down is collected in the Blow down Drum to generate stripping steam for the de-gasifier. The non-flashed blow down is cooled against combustion air to 40°C while preheating the combustion air to prevent condensing flue gasses on the flue gas side of the combustion air pre-heater. The process gas boiler is equipped with an intermittent blow down valve to remove deposits from the bottom of the shell or drum and the gas inlet tube sheet. The intermittent blow down is flashed, the resulting flashing steam is sent to safe location and the non-flashed blow down is sent to the blow down cooler. The intermittent blow down is operated with a maximum frequency of once per shift for duration of 10 seconds.

Shift Conversion

The reformer effluent is cooled to the required High Temperature Shift Reactor inlet temperature of 340°C in the Process Gas Boiler. This temperature is

maintained constant throughout the life of the High Temperature shift catalyst. The temperature is controlled by means of an internal bypass in the Process Gas Boiler, which bypasses hot reformer effluent gas from the inlet chamber to the exchanger outlet chamber. Because of this internal bypass arrangement no external refractory lined bypass around the exchanger is required. The HTS outlet temperature is about 420°C. The feedstock consumption is further reduced by implementation of a Low Temperature Shift Reactor. The inlet temperature of the Low Temperature Shift Reactor is to be increased gradually over the lifetime of the catalyst based on minimization of the CO at the exit of the reactor. During Start-of-Run the catalyst is active enough at 200°C to achieve an acceptable approach to equilibrium. Towards End-of-Run this temperature is to be increased to 230°C as a best compromise between thermodynamic equilibrium and kinetic rate. The shift section configuration has been optimized with respect to operating cost as well as plant investment cost. The CO content in the process gas will be reduced to approximately 1.1 vol% dry basis.

Process Gas Heat Recovery:

The process gas from the High Temperature Shift Reactor is cooled against saturated steam and boiler feed water. The boiler feed water temperature is normally maximized, but will be limited to about 30 °C below the boiling temperature to avoid boiling inside the heat exchanger and to avoid two phase flow to the steam drum. The process gas passes through the Low Temperature Shift Reactor and is cooled against Boiler Feed Water. During the cooling of the process gas in the boiler feed water excess steam, added to the process to drive the reforming reaction, will start to condense. Further heat recovery from the process gas is achieved by preheating demineralised water.

Process Gas Cooling:

The formed process condensate is separated from the process gas before the Process Gas Air Cooler in the Hot Condensate Separator. The final cooling of process gas to the required PSA Unit inlet temperature is achieved by cooling in

the Process Gas Air Cooler and the Process Gas Trim Cooler. The process condensate is separated from the process gas in the Cold Condensate Separator before the gas is sent to the PSA unit.

Hydrogen Purification:

Process gas from the Cold Process Condensate Separator is fed to the PSA Unit at 40°C. In the PSA Unit the hydrogen is purified adiabatically. The hydrogen leaves the PSA Unit with a pressure of 21.6 barg and a temperature of about 40°C. The hydrogen product leaves the PSA unit at a slightly higher temperature than the feed to the PSA unit due to the heat of adsorption of the impurities to the adsorbent. Therefore, hydrogen product cooler reduces the temperature to 40 °C. A small part of the hydrogen is routed back to the feed as recycle hydrogen by means of the Recycle Hydrogen Compressor.

All impurities contained in process gas leave the PSA as a purge gas and serve as primary fuel for the reformer. The PSA purge gas leaves normally the PSA Unit at a pressure of 0.30 barg. The PSA purge gas normally leaves the PSA unit at a temperature below the feed temperature due to the heat required to release the impurities from the adsorbent as well as the adiabatic expansion.

BFW preparation

In the Deaerator Boiler Feed Water is generated from imported Demin Water. The stripped water is treated with oxygen scavenger chemicals from the Chemical Dosing Unit. The BFW pumps pump the BFW to the Steam Drum. Deposit control chemicals are added to the pump discharge of the BFW pumps. The level in the Deaerator is controlled by flow control on the imported Demin water.

In the Degasifier Boiler Feed Water is generated from process condensate. The stripped water is treated with oxygen scavenger chemicals from the Chemical Dosing Unit. The BFW pumps pump the BFW to the Steam Drum. Deposit control chemicals are added to the pump discharge of the BFW pumps. The level in the Degasifier is controlled by the amount of Boiler Feed Water to the process.

The Degasifier and Deaerator are operated at close to atmospheric pressure (0.3 barg) to maximize the stripping efficiency. The boiler feed water leaves the Degasifier/Deaerator at approximately 107°C. The flow rate of BFW to the steam drum is controlled by the amount of steam leaving the steam drum and the water level in the drum (Three element control). Before entering the steam drum, the boiler feed water is preheated in the BFW pre-heaters.

Existing Hydrogen Generation Facility

In the existing Refinery, hydrogen consumers are Diesel Hydro-desulphurisation Unit (DHDS), Diesel Hydro treating Unit (DHDT), Naphtha Hydrotreater Unit (NHT), FCC Naphtha Hydrotreater Unit (FCCNHT-Prime G+) and Isomerization Unit (ISOM). A small quantity is also consumed in Sulphur Recovery Units (SRUs). MS Block (NHT/CCR/ISOM/Prime G+) is net exporter of hydrogen. Hydrogen produced in the CCR unit is partly utilized in NHT/ISOM/Prime G+ and the remaining hydrogen is routed to refinery hydrogen network after PSA.

There are two existing Hydrogen Generation Units in the Refinery.

DHDT HGU: 36 KTPA

DHDS HGU: 18 KTPA (Only about 90% of design capacity is being achieved)

VRMP Hydrogen Balance

Main consumers of hydrogen in the VRMP process units are hydro processing units.

- Full Conversion Hydrocracker
- Slurry Hydrocracker unit
- New ISOM
- Revamp of existing NHT unit will also consume additional small quantity of hydrogen.
- Revamp of existing DHT unit will also consume additional small quantity of hydrogen.
- TGTU in SRU

For meeting the hydrogen demand of VRMP units, the existing facilities are not adequate.

- Hydrogen balance is performed to estimate the new Hydrogen Generation Unit capacity
- Naphtha is considered as both fuel and feed for existing and new Hydrogen Generation Units.
- Integrated hydrogen network is considered.

Table 1 below shows estimated hydrogen consumption. This is based on following

1. For new process units (FC HCU and SHCU) hydrogen consumption is based on EIL –in house data.
2. For New ISOM unit hydrogen consumption is considered same as existing ISOM unit (93 mole% pure Hydrogen from CCR unit).

Table 7.3.1: Hydrogen Balance

Hydrogen Consumption			
Process Units	Design Capacity (MMTPA)	Hydrogen Consumption (TPD)	Remarks
NHT	1.5	11	CCR Hydrogen (93 mole% pure)
ISOM-Existing	0.229	13.5	CCR Hydrogen (93 mole% pure)
ISOM-New	0.292	17.2	CCR Hydrogen (93 mole% pure)
FCC-NHT	0.893	34	CCR Hydrogen (93 mole% pure)
DHDS	2.4	79	99.5 mole % pure & hydrogen consumption with design feed quality.
DHDT	2.64	107	99.5 mole % pure & hydrogen consumption with design feed quality.
FC HCU	3.3	313	99.5 mole % pure
SHCU	2.5	362	99.5 mole % pure
SRU-Existing	300	1	99.5 mole % pure

Hydrogen Consumption			
Process Units	Design Capacity (MMTPA)	Hydrogen Consumption (TPD)	Remarks
(TPD)			
SRU-New (TPD)	-	1	99.5 mole % pure
Total Consumption (without margin)		75	93 mole% pure
		863	99.5 mole % pure
Total Consumption (with 10% margin)		83	93 mole% pure
		948	99.5 mole % pure
Hydrogen Generation			
CCR –Existing (Post 120% Revamp)	923 KTPA	211	93 mole % pure
DHDS HGU - Existing	0	0	Considering not in operation
DHDT HGU- Existing	36 KTPA	108	99.5 mole% pure
CCR-PSA	-	60	99.5 mole% pure (while considering 221-83= 128 TPD 93 mole % hydrogen is fed to CCR PSA)
Fuel Gas Hydrogen Recovery PSA	-	105	99.5 mole% pure
Total generation without new HGU		273	
Additional Hydrogen Required	-	675 (225 KTPA)	99.5 mole% pure (=948-108-60-105)
New HGU Capacity		2*113 KTPA	With existing DHDS HGU not in operation

Capacity of New HGU: 675 TPD {225 KTPA}

New HGU configuration: 2 * 113 KTPA (2 trains of 113 KTPA each)

New fuel gas hydrogen recovery PSA has been considered with capacity of: 35 KTPA.

7.3.8 SOUR WATER STRIPPER UNIT

7.3.8.1 Refinery Sour Water Stripper (SWS I)

The typical scheme for Sour water stripper unit is shown in schematic flow diagram no: A638-02-41-00-0018-1

Refinery Sour Water Stripper is designed to treat sour water from CDU/VDU, SDA, ARU, flare KOD, acid gas condensate pumps and intermittent sour condensate from SRU & TGTU.

The H₂S recovered is sent to SRU for reduction to elemental merchant-grade Sulphur. The Ammonia-rich stream is considered to be disposed off by burning in the SRU Ammonia Incinerator. The stripped water from Single Stage SWS is sent to CDU desalter make-up and to ETP for disposal.

Sour water from above described units is received from a common line in a sour water surge drum floating on acid gas flare header back pressure. This surge drum is a three phase (V-L-L) separator. Flashed hydrocarbon vapors are separated and routed to acid gas flare. Oil carryover, if any, is skimmed off from drum and drained to OWS.

Sour water from the surge drum is pumped by single stage SWS feed pump to single stage stripper column under surge drum level control cascaded to flow controller through feed/bottom exchanger. The feed/bottom exchanger preheats the sour water feed. The stripper is equipped with a LP steam heated reboiler and a pump around circuit consisting of recirculating pumps and air cooler. Column overhead temperature is controlled by varying flow through air cooler/by-pass in pump around circuit using a three-way control valve. Column overhead pressure is controlled by controlling flow of sour gas (NH₃+H₂S) to SRU. This sour gas can also be routed to acid gas flare when SRU is under maintenance. The sour gas line to SRU should be steam jacketed. The steam flow to reboiler is controlled by a

flow ratio controller that resets steam flow in accordance with sour water feed to column.

Stripped water containing NH₃ and H₂S less than 50 wt.ppm each is pumped by stripped water pumps under level control. It is cooled in feed/bottom exchanger, before routing to CDU Desalter. A water-cooled exchanger, which is designed to cool stripped water from refinery sour water stripper and hydro processing sour water stripper, is also provided to cool the stripped water to 40 °C if the water is to be sent to the effluent treatment plant.

In order to prevent evolution of H₂S/NH₃ while draining sour water to an open sewer, a closed sour water blow down drum system is envisaged. This will consist of a blow down drum and a pump. The drum is connected to the acid gas flare in order to route all H₂S/NH₃ rich vapors that may evolve during equipment draining to flare. Provision is kept for pumping all the drain liquid collected in Blow Down drum back to sour water surge drum for stripping.

Table-7.3.2 : SWS-I Feed Stream Rates

S.No.	Unit	Unit Capacity (MMTPA)	Sour Water Rate (T/hr)	
			Continuous	Intermittent
1.	CDU/VDU	9.0	120	
2.	SDA	3.1	13.5	
3.	ARU			2.1
4.	Flare KOD + Condensate Pumps			7.6
5.	TGTU		20	
6.	HGU	2*113 (KTPA)	-	-
Total Sour Water Feed to SWS-I based on considering intermittent flows from ARU, flare KOD			163	
Considering 20% margin			196 (~ 200 TPH)	

Table-7.3.3: Existing SWS I unit Capacities

Type	Unit	Design
Non hydro-processing (SWS-I)	Merox SWSU	99.4 TPH

Hence the VRMP SWS I capacity can be considered as

Type	Without Considering Centralization	With Considering Centralization
Non hydro-processing (SWS-I), TPH	200	300 (= 200(VRMP) +99.4 (Merox SWSU))

7.3.8.2 Hydro processing Sour Water Stripper (SWS II)

The typical scheme for Sour water stripper unit is shown in schematic flow diagram no A638-02-41-00-0018-2

Hydro processing Sour Water Stripper Unit-II is designed to treat sour water from HCU, SHCU, HGU & additional load from revamp of DHDT , MS Block.

The stripped water from two stage stripper is sent separately to HCU, SHCU.

Hot Sour water is mixed with ammonia rich recycle (to keep H₂S in solution & for constructive recovery), cooled in a water cooler to 37 °C, and received in a surge drum, a three phase (V-L-L) separator. Any hydrocarbon that flashes is separated out and joins ammonia stripper overhead line to be routed to incinerator. The entrained oil, if any, is skimmed off from drum and drained to OWS. The sour water is sent to sour water storage tanks under level control. The day tanks and stripper feed pumps are normally located behind SRU ammonia incinerator vent stack. The sour water day tanks serve the following purposes:

A floating skimmer (with swivel joints and steam traced “try” lines are provided to skim off separated oil. The tanks are blanketed with nitrogen to keep off

air/oxygen. The tanks release vapors containing H₂S, ammonia (during out breathing if ammonia rich recycle stream is not available) through a fisher assembly to join SRU ammonia incinerator vent stack to release these vapors at safe height.

The sour water from tank is pumped to the 1st stage H₂S stripper column under flow control through feed/bottom exchanger where the incoming sour water feed is preheated against 2nd stage bottoms, i.e., stripper water. The feed enters the column feed tray. A slip stripped water stream quantity is taken from the inlet of feed/bottom exchanger and sent as hot wash water under flow control to the 1st stage stripper column. The temperature of this wash stream is very important for column steady performance.

H₂S stripper is equipped with MP steam heated kettle reboiler to provide the reboiling duty required. This column normally operates at a top pressure of 7.0 Kg/Cm²g and pressure is controlled by PIC in overhead vapour line. The stripping section removes most of the H₂S coming in sour water feed. The overhead wash section condenses most of the steam and almost pure H₂S is produced at the column top. This H₂S gas is routed to SRU for Sulphur Recovery, in a steam traced line.

The MP steam flows to reboiler. The steam flow to reboiler is controlled by a flow ratio controller that resets steam flow in accordance with sour water feed to column. MP condensate is routed to SRU condensate handling system. The sour water from the H₂S stripper bottom, containing almost all ammonia and small quantity of unrecovered H₂S, is fed to second stage ammonia stripper column under level control.

The ammonia stripper overhead is floating with the SRU ammonia incinerator header back pressure. The sour water is fed at the 2nd stage stripper feed tray. Alternate feed tray is also provided for operational flexibility. The section below feed tray is stripping section with two pass trays.

The required reboiling duty for this column is supplied by the LP steam heated kettle reboiler, The steam flow to reboiler is controlled by a flow ratio controller that resets steam flow in accordance with sour water feed to column.

The FRC(Flow ratio controller) cascading is with sour water feed to H2S stripper to maintain a constant rate of steam to reboiler to sour water feed to column. This ratio should be sufficient to bring down ammonia content below 50 ppmw in stripped water from column bottoms. LP condensate is routed to SRU condensate handling facility.

The overhead pump-around circuit consists of circulating reflux pumps and circulating reflux air cooler. The pump takes suction from chimney tray and circulates at a constant rate under flow control (cascaded with column top temp.). This circulating reflux is fed at the column top. The ammonia (with small H2S quantity) coming out from column top is routed to SRU ammonia incinerator through a steam jacketed line.

An ammonia-rich slip stream from pump-around circuit (before air cooler), under flow control, serves as recycle stream to be mixed in hot sour water feed, before feed mix cooler, during normal operation.

Table- 7.3.4: SWS-II Feed Stream Rates

S.No.	Unit	Unit Capacity (MMTPA)	Sour Water Rate (T/hr)
1.	Full Conversion Hydrocracker Unit	3.3	69
2.	Slurry Hydrocracker Unit	2.5 (10% margin)	59
3.	NHTU	30% Revamp	2 (Note-1)
	Total Sour Water Feed to SWS-II		128
	With 20% margin		154 (~ 160)

Table-7.3.5: Existing SWS unit Capacities

Type	Unit	Design
Hydro Processing (SWS-II)	DHDS SWSU (Non Operational)	6 TPH
	VRCFP SWSU (includes DHT)	21 TPH

Hence the VRMP SWS II capacity can be considered as

Type	Without Considering Centralization	With Considering Centralization
Hydro Processing (SWS-II), TPH	160	185 (= 160(VRMP)+ 21 (VRCFP))

7.3.9 SULPHUR RECOVERY UNIT (With Tail Gas Treatment Unit)

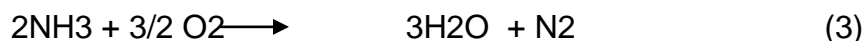
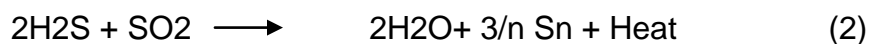
7.3.9.1 Sulphur Recovery Unit

The typical scheme for sulphur recovery unit is shown in schematic flow diagram no A638-02-41-00-0019-1

Feed to SRU comprises of acid gas from ARU and sour gas from SWSU. Acid gas from ARU passes through acid gas knock out drum, to remove any liquid carryover, before feeding to main burner. Similarly, any liquid carryover in sour gas from SWSU is removed in sour gas knock out drum.

The air to main burner is supplied by an air blower, which also supplies air to Super Claus stage and sulfur degassing. The air to the main burner is exactly sufficient to accomplish the complete oxidation of all hydrocarbons and ammonia present in the feed gas and to burn as much H₂S as required to obtain desired concentration. The heat generated in the main burner is removed in the waste heat

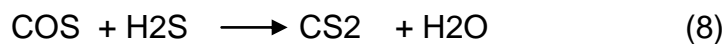
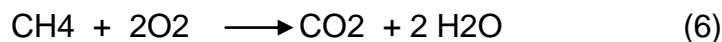
boiler by generating steam. Then the process gas is introduced into the first condenser in which it is cooled, sulfur vapor condensed and is separated from gas. Upstream of 1st Claus reactor, the process stream from waste heat boiler is heated in 1st steam reheater to obtain optimum temperature for the catalytic conversion. The effluent gases from 1st reactor passes onto 2nd sulfur condenser where sulfur vapor is condensed and uncondensed process gases pass to the 2nd steam reheater. Heated vapors are again subjected to conversion in the 2nd Claus reactor followed by cooling in the 3rd sulfur condenser. Then the process gas passes to the 3rd steam reheater and the 3rd Claus reactor. Following reactions takes place inside the Claus reactor

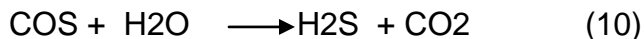


The sulfur formed remains in vapor phase and goes in polymeric reaction, which forms polymeric sulfur in vapor phase. The predominate reactions are



Some of these combustion reactions also take place in the burner section of the reaction furnace. The list of reactions taken place in the reaction furnace are given below:





The unconverted H₂s from the clause reactor is sent to the TGTU unit. Sulfur condensed in condensers is routed via sulfur locks to sulfur cooler and drained into sulfur degasification vessels. Stripping air is supplied to the spargers located at the bottom side of the vessel. This strips off H₂S from liquid sulfur and oxidizes the major part of H₂S to sulfur. Air leaving the stripping columns, together with H₂S released from sulfur degasification vessel, is routed to TGT Unit. Liquid Sulphur from pit is pumped by sulphur pumps to Sulphur Yard .

Sulphur Balance

The existing refinery has two installed SRUs:

Existing SRUs

Table-7.3.6: Existing SRU unit Capacities

Unit	Capacity (TPD)	Recovery (%)
DHDT SRU	300X1	99.9
VREP SRU	65X3	99.8

In existing configuration,

- Old SRU Block comprise of 3 parallel Claus trains, each of capacity 65 MTPD sulfur production . TGTU for each train is under implementation.
- DHDT SRU : One train of capacity 300 TPD Sulphur production with TGTU under DHDT project

Post VRMP (15 MMTPA Crude throughput) SRU Capacity

- Post VRMP, Total required capacity of Sulfur Recovery Unit (MTPD) : 970

This capacity is worked out considering the followings

- Refinery capacity : 15 MMTPA
- Crude :Mix of 80% HS crude (Basra light) and 20% LS crude (Bonny light)

Doba crude not considered

- SOX limit of 11.5 TPD

Total SRU capacity is worked out based on sulfur Balance as provided in Table-1

- Capacity of New SRU (MTPD) : 475 = {970-(195+300)}
With 10% Margin : 520 MTPD
- New SRU with Two trains can be considered.

Capacity of Each Train of New SRU

The following options has been examined

1. Option-1 : With full capacity utilization of all existing units
2. Option-2 : Without Old SRUs of 195 TPD
3. Option-3 : Considering 2 new trains of 300 TPD (same as DHDT SRU Train) with full capacity utilization of all existing trains

Option-1: With full Capacity Utilization of all existing SRU units

Total New SRU Capacity : 520 TPD

New SRU configuration: 2* 260 (2 trains of 260 TPD)

In this option:

1. One unit Shutdown of unit due to boiler inspection, No spare capacity may available, therefore either refinery to be operated at lower capacity or lower Sulphur crude to be processed.
2. One unit Shutdown of unit due to boiler inspection: Refinery to be operated either
 - a. At lower throughput (74%)
 - b. With lower sulphur crude 36 % and balance high Sulphur crude
 - c. Combination of above

Option-2: Without Old SRUs of 195 TPD :

Total New SRU Capacity : 715 TPD (520+195)

New SRU configuration: 2* 360 (2 trains of 360 TPD)

In this option:

1. One unit Shutdown of unit due to boiler inspection: Refinery to be operated either
 - a. At lower throughput (64%)
 - b. With lower sulphur crude 48 % and balance high Sulphur crude
 - c. Combination of above
2. Space availability shall be examined.

Option – 2A: In consideration of old SRU of 195 TPD and 2 new trains of 360 TPD :

1. One unit Shutdown of unit of max capacity (360TPD) due to boiler inspection:
Refinery to be operated either
 - a. At lower throughput (83%)
 - b. With lower sulphur crude 32 % and balance high Sulphur crude
 - c. Combination of above

Option-3: Considering 2 new trains of 300 TPD (same as DHDT SRU Train) :

In this option:

1. Trains with same capacity that to DHDT SRU .
2. One unit Shutdown of unit due to boiler inspection:
 - a. Refinery to be operated at lower throughput (77%)
 - b. With lower sulphur crude 37 % and balance high Sulphur crude.

Conclusion:

1. The summary of all options are summarized below :

Table-7.3.7: New SRU Options

	Option-1	Option-2	Option-2 A	Option- 3
Old SRU Capacity, TPD	195	0	195	195
DHDT SRU Capacity, TPD	300	300	300	300
New SRU, TPD	520 (2 X 260)	720 (2 X 360)	720 (2 X 360)	600 (2 X 300)
Refinery throughput/ LS crude processing in case of One SRU turn down of max capacity	74%	64%	83%	77 %
	36 % LS Crude Processing	48 % LS Crude Processing	32 % LS Crude Processing	37 % LS crude Processing

2. For option-1 i.e. full capacity utilization of existing SRU units, capacity of new SRU required is 520 MTPD (2 X 260).
3. For option-2 i.e without Old SRUs of 195 TPD, capacity of new SRU required is 720 MTPD (2 X 360).

Selected Option: Option 2A with 2 * 360 TPD new SRU

The sulphur balance of the refinery in the expansion phase is worked out. The same is indicated as follows:

Table-7.3.8: Sulphur Balance

	TPD	S (ppmw)	TPD of S
Feed			
Basara Light	36000	28700	1018.8
Bonny Light	9000	1500	13.5
Doba	0	1200	0
Total Feed Sulphur			1032.3
Products			
Naphtha	589	177.20	0.104
Jet Fuel	91	1685.90	0.153
Kerosene Zone	2079	1685.90	3.505
MS-IV	5251	40.00	0.210
MS- V	1215	8.00	0.010
Diesel -IV	19950	40.00	0.798
Diesel - V	7253	8.00	0.058
Light Diesel Oil	93	2667.10	0.248
Bitumen	661	47265.70	31.243
SHC Pitch	724	23080.00	16.710
Fuel Oil - Internal	798	4851.20	3.871
Coke Burnt FCC-1	133	5182.40	0.689

	TPD	S (ppmw)	TPD of S
Coke Burnt FCC-2	130	27679.00	3.598
Total Product Sulphur			61.198
Balance			971
Existing SRU Capacity			495
New SRU Capacity			476

Sulfur Balance	(in TPD)
Total Sulphur in Feed	1032.3
Total Sulphur in Products & fuel	61.2
SRU Capacity Required	971
Existing SRU capacity	300+195
NEW SRU capacity Required	476
NEW SRU capacity Required (10% Margin)	~ 520

- Sulphur Recovery Units has been considered with Tail Gas Treating (TGT) facilities. Total sulphur recovery is 99.9%.

7.3.9.2 Tail Gas Unit.

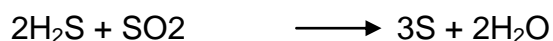
The typical scheme for sulphur recovery unit is shown in schematic flow diagram no A638-02-41-00-0019-2

The Tail Gas Treating Section is required for the removal of sulphur compounds (H₂S, SO₂, COS, CS₂, elemental sulphur) from the tail gas from the Claus Section. This is achieved by catalytic reduction of sulphur compounds to hydrogen sulphide and the subsequent absorption of hydrogen sulphide in a regenerable absorption medium (Amine).

Rich amine is subsequently treated in Amine Regeneration Section in order to release the absorbed hydrogen sulphide which is recycled back to the Claus section for further recovery of elemental sulphur. The H₂S recycled allows an overall sulphur recovery efficiency of 99.9% to be achieved.

Tail gas enters the hydrogenation reactor preheated at 130°C. H₂ reducing gas is mixed with Claus tail gas in the preheat effluent stream via a controller which is reset by the SO₂ concentration in the down stream of the hydrogen reactor. The effluent is preheated under temperature controller by an electrical heater. A pre-sulfiding line is provided to activate the TGU catalyst using acid gas from the acid gas KOD. Thus line is not used for normal operation.

The hot preheated effluent passes through the catalyst bed of the hydrogenation reactor where SO₂ and other sulfur compounds are converted to H₂S. Due to exothermic reaction, the gas temperature increases. The reactor inlet temperature should be held reasonably steady to provide stable conditions in the reactor. To avoid excessive outlet temperature, the inlet gas may be controlled at somewhat lower temperature to compensate for more SO₂ and/or S in the tail gas feed. However, excessively low reactor inlet temperature will result in poor conversion. The SO₂ monitor at the reactor effluent is observed to maintain an excess of ~3% H₂. In addition, if the circulating water in the quench loop shows the presence of finally divided sulfur this indicates incomplete reaction and the SO₂ has reached the column to form sulfur via the Claus reaction:



This behavior should be monitored as the presence of the sulfur not only means the reaction is incomplete but the column can be plugged. Monitoring the pH of the quench water provides a pre-warning to an impending problem. The pH should be maintained near 7.0.

Hot reactor exit gas must be cooled before entering the absorber. A first stage gas cooling is accomplished by generating steam at the TGU waste Heat Boiler, decreasing the process gas temperature. BFW is fed to the shell side of the TGU-WHB on level control and low pressure steam is generated. When the steam flow and/or BFW flow rate changes, the water level in the steam generator varies. Rising level in the generator indicates that the BFW flow rate is exceeding the rate of steam

generation. In this case, signal to the level control valve will decrease. If the steam generation exceeds the BFW rate, level will decrease. In this case, signal to the level control will increase.

The process gas enters the quench column. The quench water recirculating loop consists of the quench water pump, filter and water cooler. The cooler removes the heat from the column, cooling the inlet gas. The water flow to the top of the column is controlled after being filtered by quench water filter. Decreasing the water flow rate will increase the bottom temperature. Increasing the water rate will increase the load in the quench water circulation pumps and flow through the quench water cooler and column.

The quench column recirculation system has the provision to adjust the pH by addition of caustic to the column recirculation line. The pH of the quench water to the water pump is monitored and kept at a value between 7 and 9 in an effort to prevent corrosion and inhibit colloidal sulfur formation. The water system should be visually inspected for cloudiness. Low pH will indicate incomplete reduction of sulfur compounds.

Sour water condensed from the inlet feed is removed from the quench water loop via a level controller from the quench column and is sent offsite to sour water storage. The rate depends on the water in the Claus tail gas, water produced in the hydrogenation reactor and the amount of water overhead in the quench column.

Downstream of these reactors, additional recovery of reduced sulfur is accomplished in an amine absorber column that uses an aqueous methyl di ethanolamine (MDEA) solvent to scrub H₂S from the TGTU tail gas. The overhead stream from this contactor, containing very low sulfur levels, is sent to the tail gas thermal oxidizer for disposal. The rich MDEA solvent is regenerated in the TGTU amine stripper and H₂S is returned to the inlet of the Claus SRU trains to be recovered. Regenerated MDEA solvent is recirculated back to the TGTU amine absorber column.

Tail gas from TGU is routed to the incinerator where residual sulfur is converted to SO₂ and discharged into the atmosphere.

The overhead line from the quench column flows to the absorber. The absorber is a

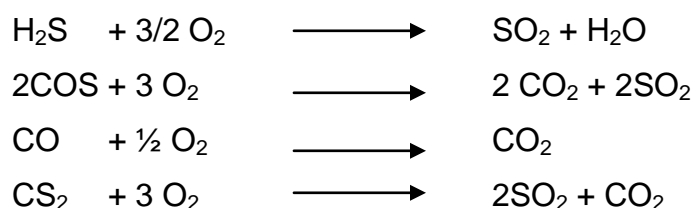
packed column and is designed to absorb practically all the H₂S in the recirculating Amine solvent. amine absorber column that uses an aqueous methyl diethanolamine (MDEA) solvent to scrub H₂S from the TGTU tail gas. The overhead stream from this contactor, containing very low sulfur levels, is sent to the tail gas thermal oxidizer for disposal. The rich MDEA solvent is regenerated in the TGTU amine stripper and H₂S is returned to the inlet of the Claus SRU trains to be recovered. Regenerated MDEA solvent is recirculated back to the TGTU amine absorber column.

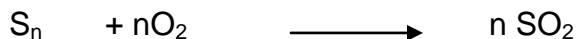
The purpose of the incinerator system is to oxidize all the sulfur compounds in the tail gas to SO₂ and to vent the oxidized stream at high temperature and at a high elevation.

The incinerator system included the two primary sections:

- In the incinerator burner, fuel gas is burnt with excess air to a temperature over 1650°C. The temperature is sufficient to heat the tail gas from TGU to ~768°C. This temperature is sufficient to oxidize the residual H₂S and sulfur compound, while minimize NO_x and SO₃ formation.
- The effluent is discharged to the incinerator stack. The stack height of 60 meters is set to ensure dispersion of SO₂ and to meet ground level concentration limits.

Effluent tail gas from the TGU absorber is thermally oxidized with air to convert reaming sulfur compounds to SO₂. Fuel gas and excess air are combusted at high temperature at the incinerator burner. Then it is mixed with the absorber overhead effluent tail gas in the primary oxidation chamber. The fuel gas and air rates are adjusted to control the temperature of the mixed and oxidized tail gas stream. The air is supplied by a dedicated incinerator air blower. Excess air is used to ensure sufficient oxygen is present to oxides the sulfur and other sulfur compound. Oxidation reactions are as follows:





The incinerator effluent temperature is measured and used to adjust the flow rate of fuel gas to maintain the desired operating temperature of 768°C. The incinerator is refractory lined with an external thermal shroud to control the shell temperature. Skin thermocouples are provided to monitor the shell temperature. The shell temperature should be maintained between 149 – 350°C.

The air blower is designed to provide supply of air and stack while providing a minimum of 2% excess O₂ at an operating temperature of 768°C. Ambient air is drawn through the inlet filter to remove solid debris and to protect against water during heavy rainfall.

The combustion gas from the burner and combustion chamber flow into the incinerator where adequate residence time is provided for combustion. The incinerator stack vents the effluent to the atmosphere. A SO₂/O₂ analyzer is provided to determine the SO₂ and O₂ in the effluent stream.

7.3.10 LPG TREATING UNIT:

7.3.10.1 SR LPG Amine Treater:

The typical scheme for SR LPG Amine treater unit is shown in schematic flow diagram no A638-02-41-00-0020-1

The objective of the LPG Amine Treater Unit is to remove H₂S before LPG is sent for mercaptan removal.

Sour LPG is routed to LPG Amine Absorber for removal of H₂S. About 70-80% of Lean Amine under flow control is mixed with LPG in online LPG-Lean Amine Mixer. Heat of absorption is removed in LPG-Amine Cooler, where LPG + Amine mixed stream is cooled to 40 °C and fed to LPG Amine Absorber column. Balance 20-30 % Amine is routed to column top. Sweet LPG from top is routed to Amine Settler Drum. Any carryover of amine with LPG shall settle down in this vessel. From here, LPG is routed to mercaptan removal unit. Rich Amine from

Regenerator Column bottom is routed to ARU section under interface level control.

An Amine sump is also provided where the amine drain from LPG AAU equipment are collected.

7.3.10.2 SR LPG Merox

The typical scheme for SR LPG Caustic Treatment unit is shown in schematic flow diagram no A638-02-41-00-0020-2

The objective of the LPG Caustic Wash Unit is to remove any residual H₂S and mercaptans before LPG product is sent to storage.

H₂S Removal

The LPG feedstock from LPG Amine Treater Unit shall enter a batch caustic pre-wash where LPG is contacted with caustic solution to ensure the complete removal of H₂S.

Mercaptan extraction:

Extraction of mercaptans from the LPG into the aqueous phase is completed in a vertical, multi-trayed extraction column using strong sodium hydroxide (NaOH) solution containing a small amount of soluble Merox WS reagent. LPG from the pre-wash enters near the bottom of the column and regenerated caustic solution is pumped to the top. Each tray comprises a caustic inlet reservoir, a central mixing zone where the up-flowing LPG contacts the cross-flowing caustic and an outlet weir and down-comer to allow the caustic to transfer to the next tray by gravity flow. Treated LPG leaves the top of the column for post-treatment while the caustic now loaded with mercaptide [NaSR] is sent to the caustic regeneration section; the bottom of column serving as a caustic reservoir for the system.

Post Treatment

The treated LPG goes overhead through a caustic knockout drum to a sand filter which removes any trace of caustic solution before it passes out of the unit to storage.

Caustic Regeneration

The mercaptan-rich caustic solution exits the bottom of the extraction column to the caustic regeneration section through a small steam heater which helps maintain temperature in the oxidiser during cold weather. Air is continuously injected into the caustic stream as it flows upward through the oxidiser and where mercaptans as sodium mercaptide are readily converted to the corresponding disulfides in the presence of the Merox WS reagent. The 3-phase mixture of spent air, disulfide oil and regenerated caustic solution is then routed to a disulfide separator. Spent process air, depleted by about 50% of the oxygen content, is normally diluted with fuel gas and vented to a fired heater convenient to the Merox unit while the disulfide oil is decanted and sent to DHT/storage. The regenerated caustic stream complete with the Merox WS reagent is returned to the extraction column.

Table-7.3.9: Existing LPGATU/LPG CFC Units

S.No.	Existing Unit	Unit Capacity (TPD)
1.	SR LPG Treater	360
2.	CR LPG Treater	1480

Sour LPG generated from following new units:

- Crude Distillation Unit / Vacuum Distillation Unit (CDU/VDU-IV)
- Full Conversion Hydrocracker (FCHCU)
- Slurry Hydrocracker (SHCU)

The sour LPG feed stream summary is given in table-7. The data considered is based on EIL in house data.

Table- 7.3.10 LPG ATU / LPG CFC Feed Stream Rates

S.No.	Unit	Unit Capacity (MMTPA)	Sour LPG Rate (T/hr)
1.	Crude / Vacuum Distillation Distillation Unit	9.0	11.33
2.	Full Conversion Hydrocracker Unit	3.3	Note 1
3..	Slurry Hydrocracker Unit	2.5	Note 1
	Total Sour Gas Feed to LPG ATU		11.33
	With 20% margin		14

Note-1: Treating Unit has been considered inside the unit only

Quantity of Sour LPG for treatment is (around 14 T/hr) so new LPG treating/CFC to be considered in VRMP.

7.3.11 AMINE REGENERATION UNIT

The typical scheme for Amine Regeneration unit is shown in schematic flow diagram no A638-02-41-00-0021

The function of Amine Regeneration units is to remove the acid gases (H₂S and CO₂) from the rich amine streams produced in the refinery processing units.

Rich amine from various absorber units is received in a flash column. Rich amine is allowed to flash in the column to drive off hydrocarbons. Some H₂S also gets liberated. The liberated H₂S is again absorbed by a slip stream of lean amine solution making counter current contact with liberated gases over a packed bed.

From the flash column, the rich amine is pumped by rich amine pumps under flow control to amine regenerator, after preheating in lean amine/rich amine exchanger. In lean amine/rich amine exchanger, the heat is supplied to rich amine by hot lean amine on shell side from the bottom of amine regenerator under level control. The lean amine from lean amine/rich amine exchanger is further cooled in lean amine cooler and routed to amine storage tank. Another part of lean amine from lean

amine cooler is used as slip steam to cartridge filter to remove solid particles picked up amine in the system. It is also used to remove foam causing hydrocarbon substances and thereafter routed to amine storage tank.

In amine regeneration column, reflux water enters the column top and descends down. This prevents amine losses into the overhead and ensures complete removal of H₂S. The reboiler vapors from the bottom of the tower counter currently contacts the rich amine and strips off H₂S. The overhead vapors from regenerator are routed to regenerator overhead condenser, where most of the water vapors condense and are pumped by amine regenerator reflux pumps as reflux to the column. The acid gases are routed to the SRU. In case the pressure goes high, acid gases are released to the acid flare. Reboiler heat by LP steam is supplied to the column through amine regenerator reboiler.

Table- 7.3.11: Existing ARU capacities:

Unit	Capacities Cum/hr	
	Design	Operating
VREP II Merox	70	25
DHDS	227	175
VRCFP	145	85
DHT	300 T/hr	-

Feed to ARU from new units will consist of rich amine generated from

- FG ATU
- LPG treating Units
- Full Conversion Hydrocracker (FCHCU)
- Slurry Hydrocracker (SHCU).

The rich amine feed stream summary is given in table-8. The data considered is based on EIL in house data.

Table - 7.3.12: Rich Amine Feed Stream Rates

S.No.	Unit	Unit Capacity (MMTPA)	Rich Amine Feed Rate (T/hr)
1	LPG ATU	0.108	4.5
2.	Full Conversion Hydrocracker Unit	3.3	325
3	Slurry Hydrocracker Unit	2.5 * 1.1	386
	Total Rich Amines Feed to ARU		716
	Total With 20% margin		860

Centralization of ARUs units

As a part of DFR revision, feasibility of centralization of ARU units in the Refinery will be worked out.

Total ARU capacity is coming as 1445 m³/hr {860+25+175+85+300}. This is considering operating capacities in existing ARUs.

Three Options have been examines

- Option-1: Without considering existing ARUs capacities & operating capacity of same are considered (285 m³/hr)
- Option-2: With considering all existing ARUs
- Option-3: Without considering existing ARUs capacities & design capacity of same are considered (442 m³/hr)
- Option-4: Without considering existing VREP II & VRCFP ARUs capacities & design capacity of same are considered (70+145=215 m³/hr)

Option 1: Without considering existing ARUs capacities & operating capacity of same are considered (285 m³/hr)

- The DHT ARU (300 T/hr) is considered.
 - ARU Capacity for new units : 860 m³/hr
 - Existing ARU capacity (operating) : 285 m³/hr
 - Total capacity for New ARU : 1145 m³/hr.

So besides 300 cum/hr of DHT ARU, **two trains of new ARUs of 575 cum/hr each shall be considered under VRMP**

Option 2: With considering all existing ARUs

- Considering the present DHT ARU (300 T/hr) and other existing ARUs (285 m³/hr)
- New ARU capacity will be 860 m³/hr .
So besides 300 cum/hr of DHT ARU, and existing ARUs **two trains of new ARUs of 430 cum/hr each shall be considered under VRMP.**

Option 3: Without considering existing ARUs capacities & design capacity of same are considered (442 m³/hr)

- Considering the present DHT ARU (300 T/hr)
- ARU Capacity for new units : 860 m³/hr
- Existing ARU capacity (operating) : 442 m³/hr
- Total capacity for New ARU : 1302 m³/hr.

So besides 300 cum/hr of DHT ARU, **two trains of new ARUs of 650 cum/hr each shall be considered under VRMP.**

Option-4: Without considering existing VREP II & VRCFP ARUs capacities & design capacity of same are considered (70+145=215 m³/hr)

- Considering the present DHT ARU (300 T/hr)
- ARU Capacity for new units : 860 m³/hr
- Existing VREP II & VRCFP capacity (Design) : 215 m³/hr
- Total capacity for New ARU : 1075 m³/hr.

So besides 300 cum/hr of DHT ARU & 227 cum/hr. DHDS ARU's, **two trains of new ARUs of 540 M³/hr each shall be considered under VRMP.**

Final Selected Option: Option 4 with two trains of new ARUs of 540 M³/hr each.

7.3.12 FG ATU

The typical scheme for Fuel Gas Amine Treatment unit is shown in schematic flow diagram no A638-02-41-00-0022

The objective of the Fuel Gas Treater Unit is to remove H₂S before fuel gas is routed to refinery fuel gas network.

Sour fuel gas is sent to fuel gas Amine Absorber for removal of H₂S. Lean Amine from ARU is pumped through flow control to column top. Treated fuel gas from top is routed to fuel gas knock out drum. Any carryover of amine with fuel gas shall be removed in this vessel. From here, fuel gas is routed to refinery fuel gas network. Rich Amine from absorber Column bottom is pumped to ARU section under level control for regeneration.

The sour FG feed stream summary is given in following table. The data provided is based on EIL in house data.

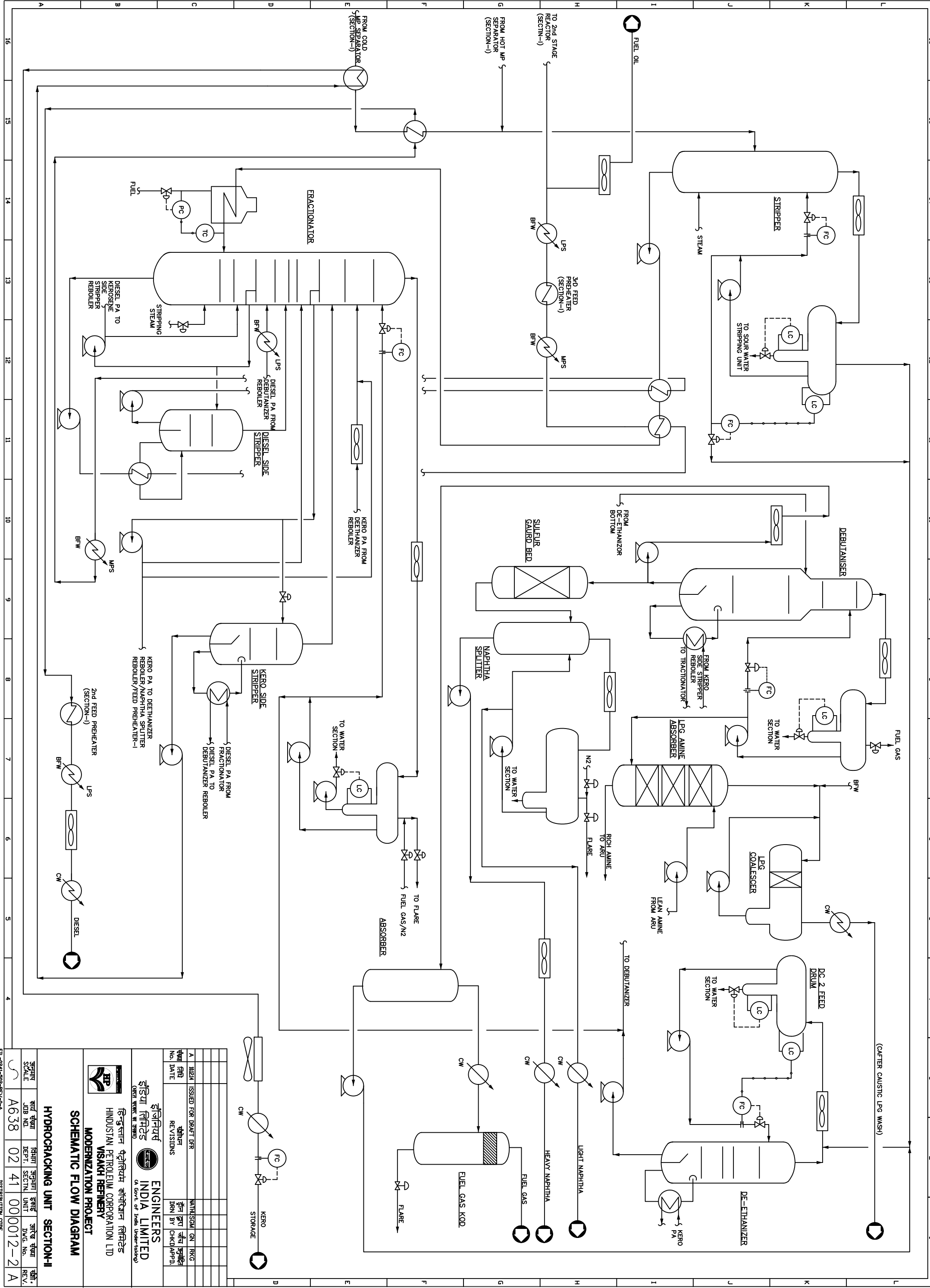
Table 7.3.13- : FG ATU Feed Stream Rates

S.No.	Unit	Unit Capacity (MMTPA)	Sour FG Rate (T/hr)
1	Crude / Vacuum Distillation Distillation Unit	9.0	0.1(Note -2)
2	Full Conversion Hydrocracker Unit	3.3	Note 1
3	Slurry Hydrocracker Unit	2.5 (10% Margin)	Note 1
4	NHTU	30% Revamp	0.11 (Note-2)
	Total Sour Gas Feed to FG ATU		0.21
	With 20% margin		0.25

Note-1: Treating Unit has been considered inside the unit only

Note-2: Can be processed in Existing FG ATU.

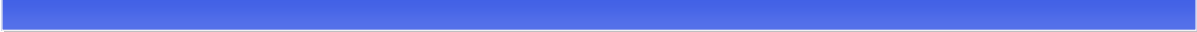
Quantity of Sour FG gas generated from new units and additional sour gas from revamped units is very less (~0.3 t/hr).so new FG ATU will not be considered in VRMP.



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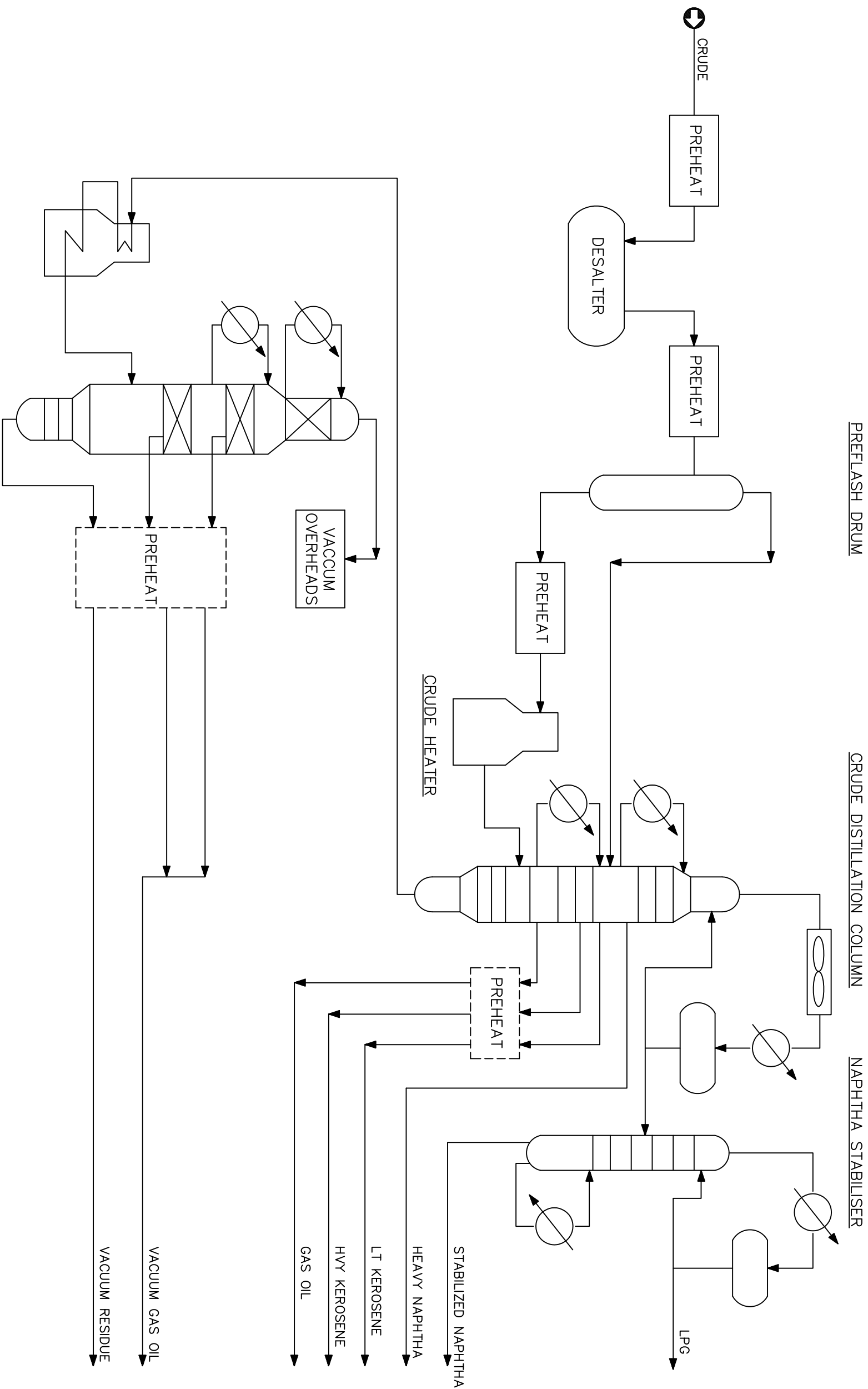
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 Dept. No. 02
 Unit No. 41
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 Rev. No. A



ANNEXURE II

PROCESS FLOW SCHEME





VACUUM HEATER VACUUM DISTILLATION COLUMN

PREFLASH DRUM

CRUDE DISTILLATION COLUMN

NAPHTHA STABILISER

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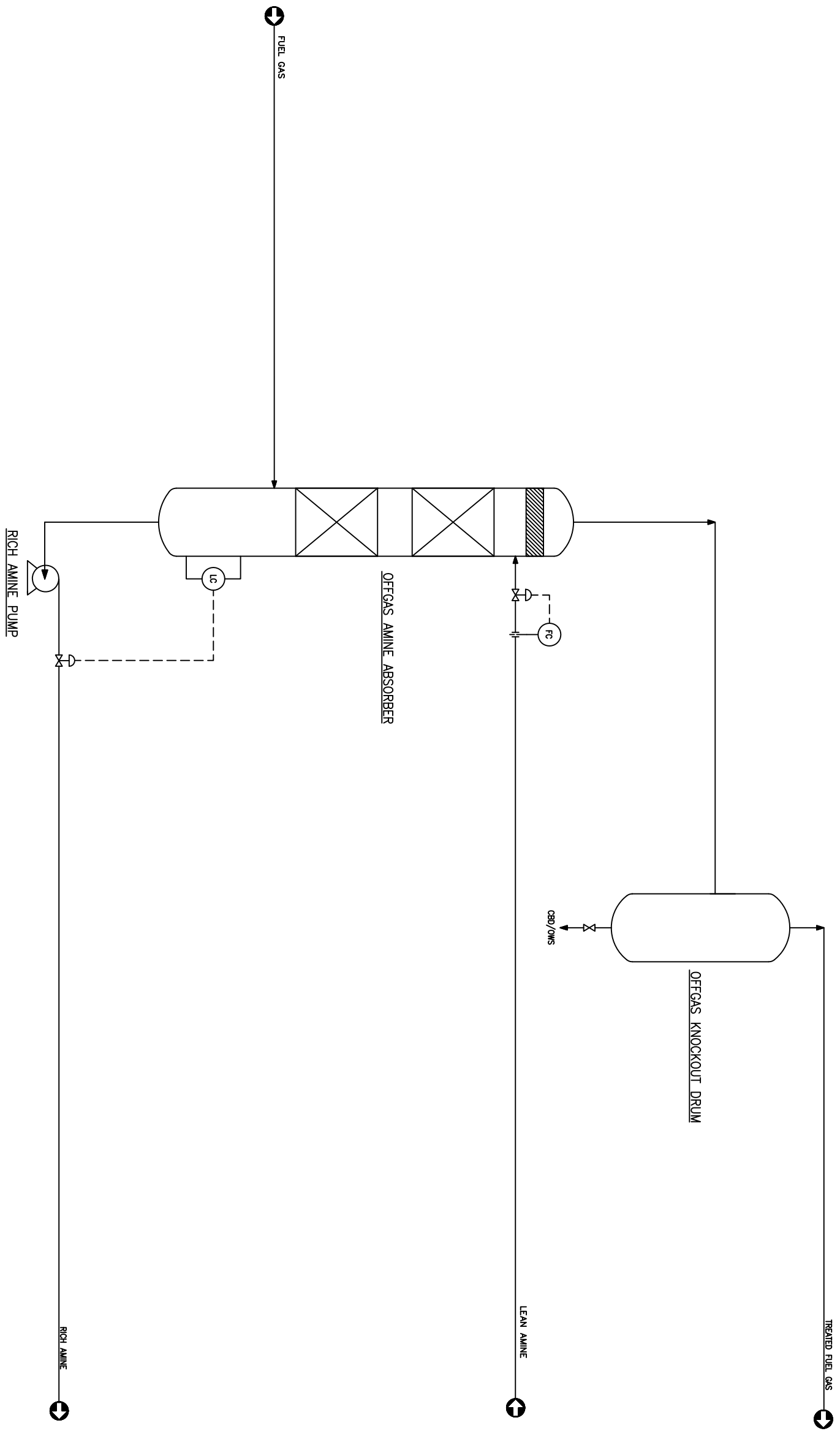


SCHEMATIC FLOW DIAGRAM
 CRUDE/VACUUM DISTILLATION UNITS

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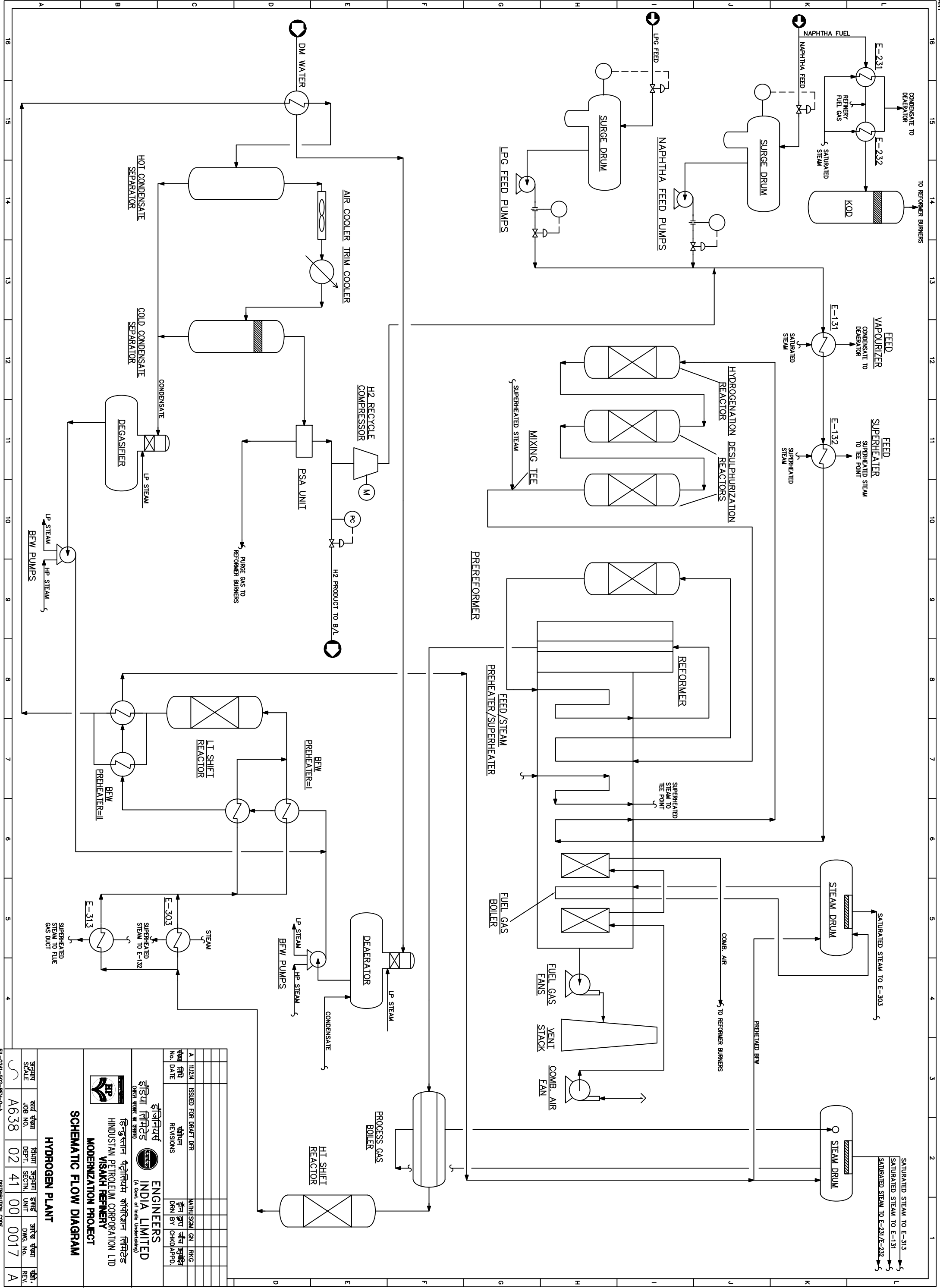
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SCHMATIC FLOW DIAGRAM
FUEL GAS AMINE TREATING UNIT

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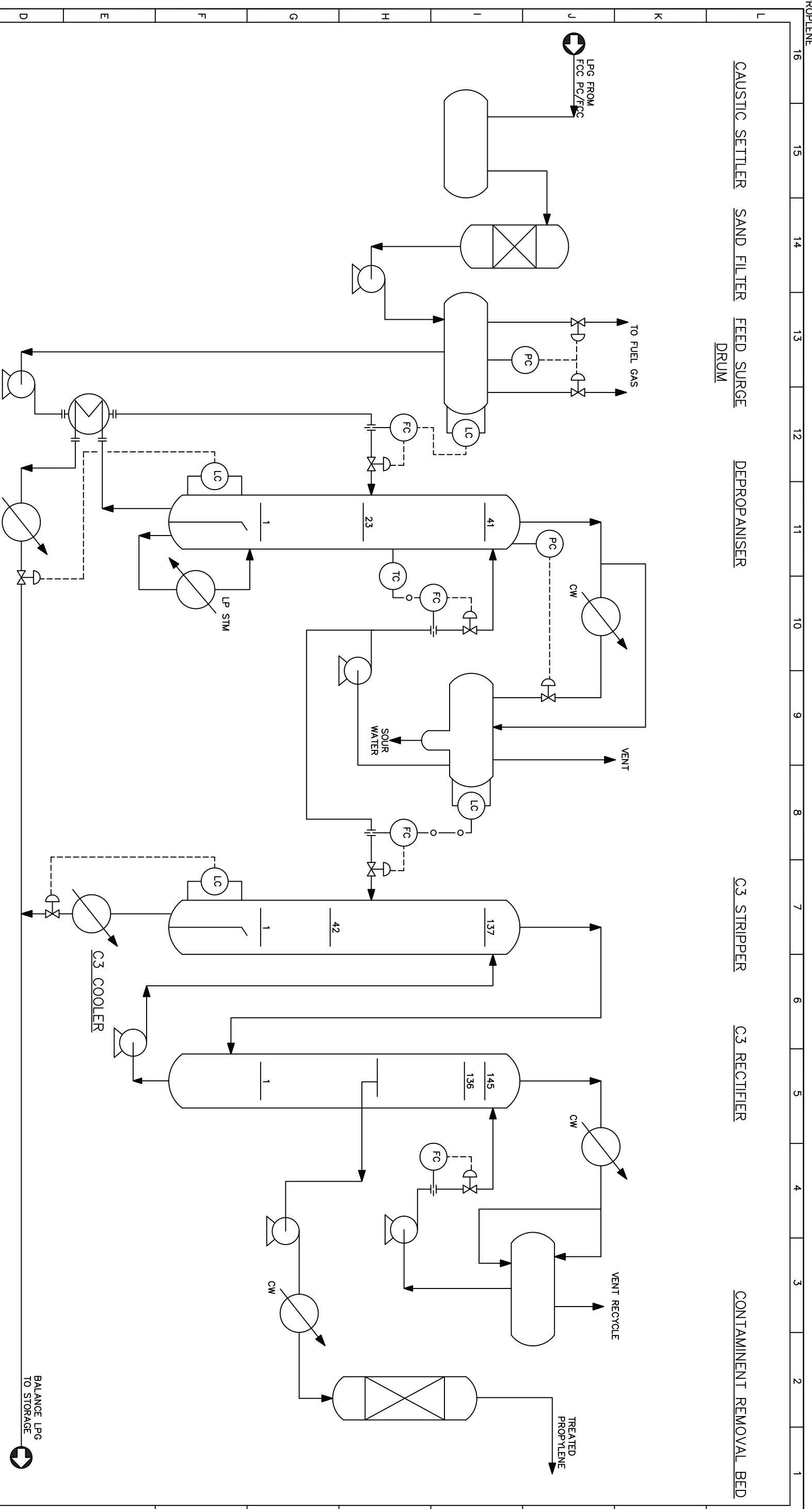
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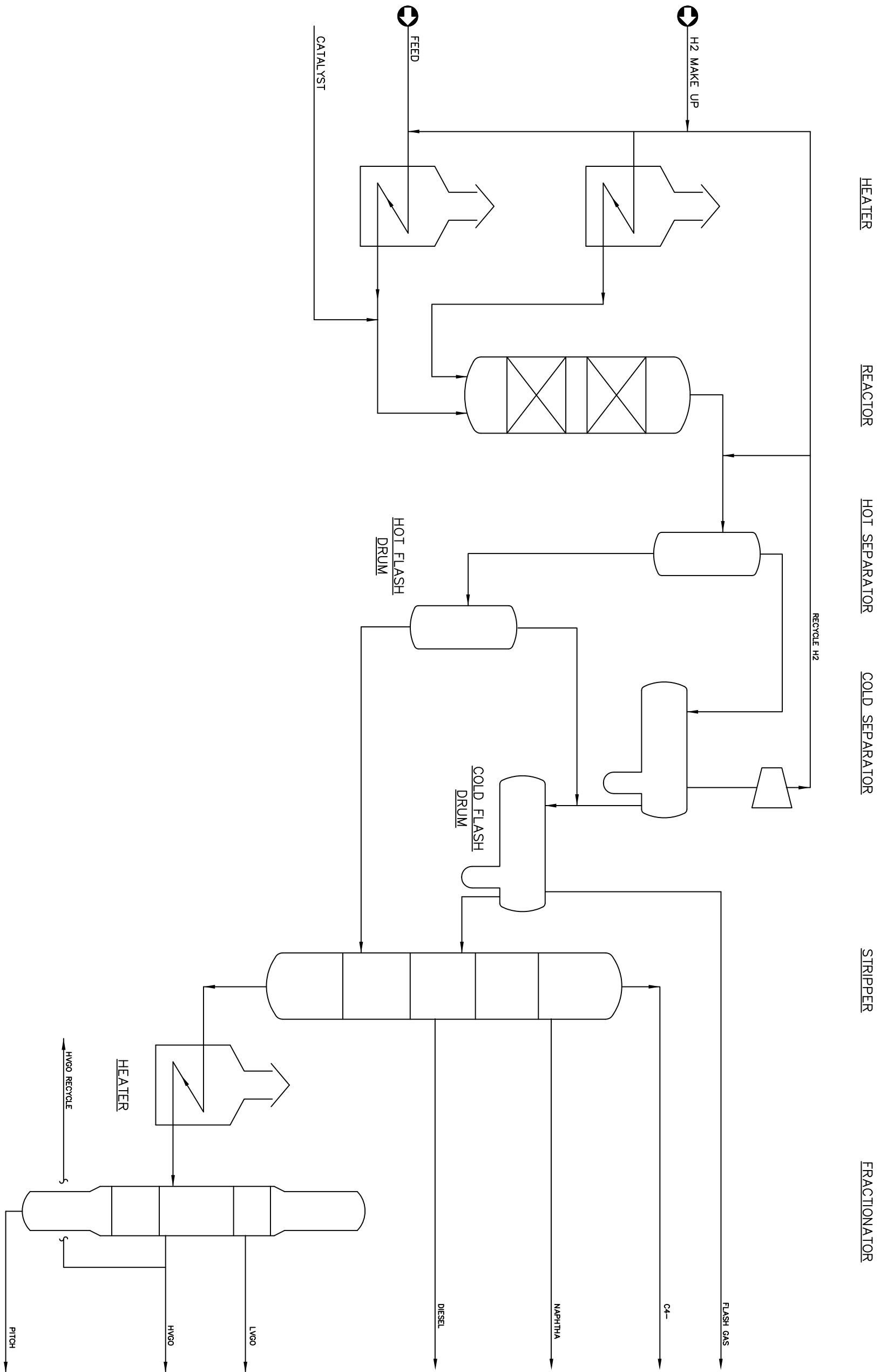


FEED PUMPS C4 COOLER

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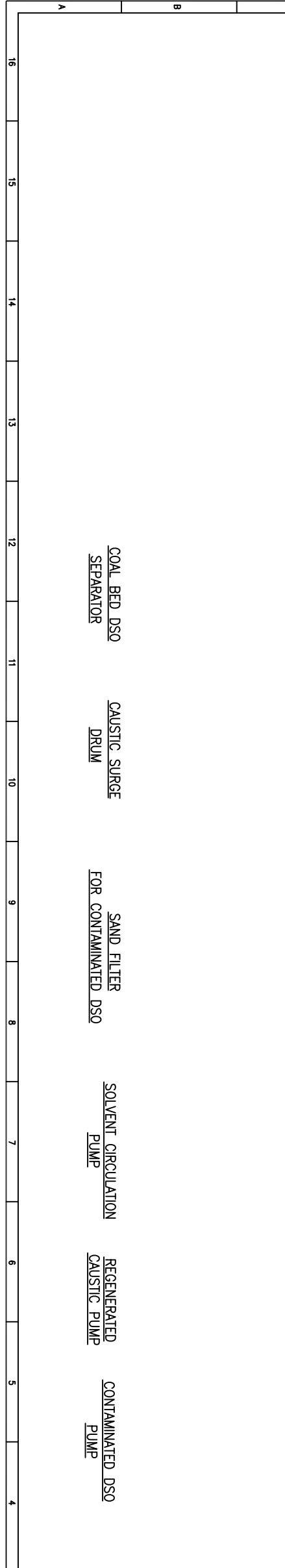
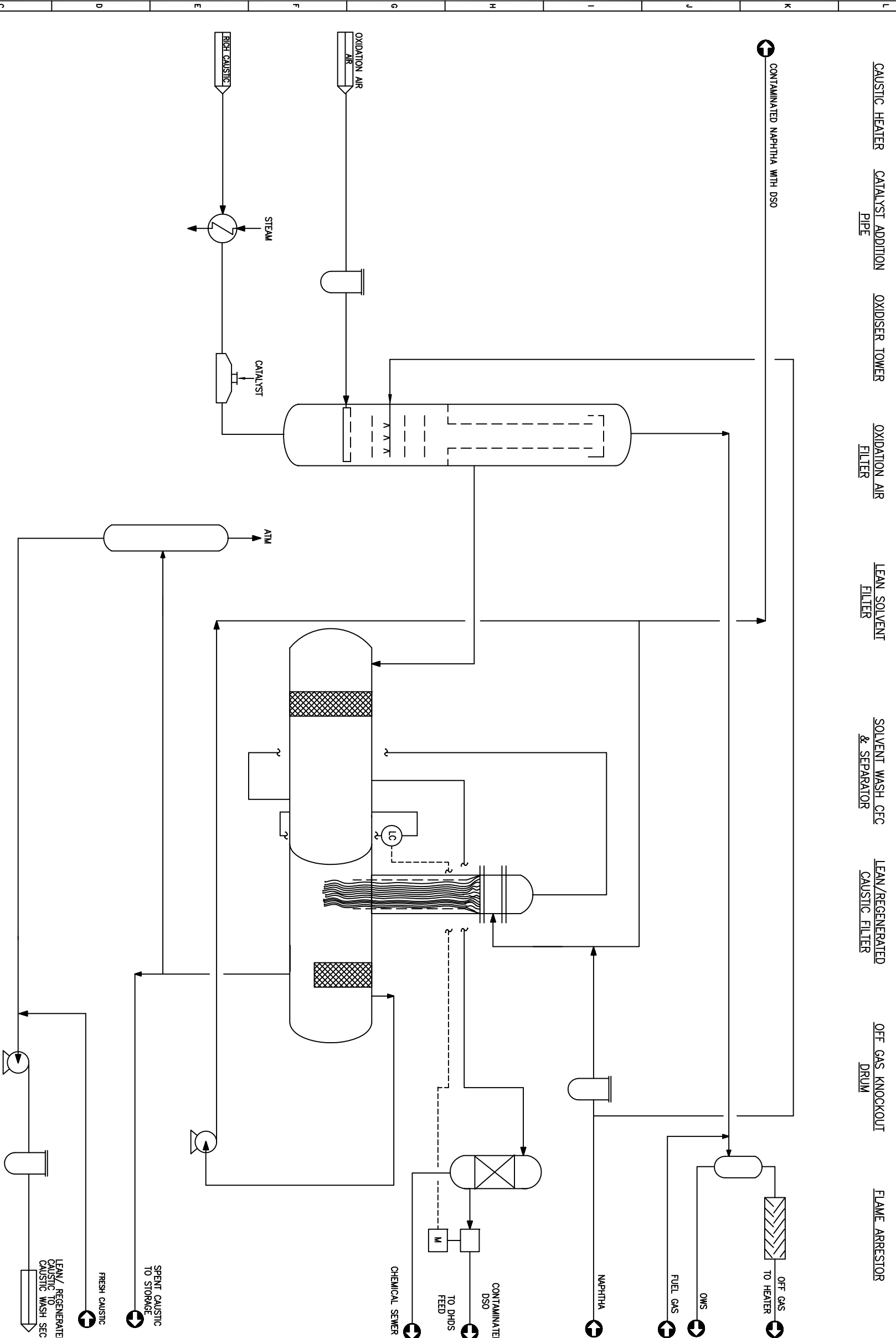


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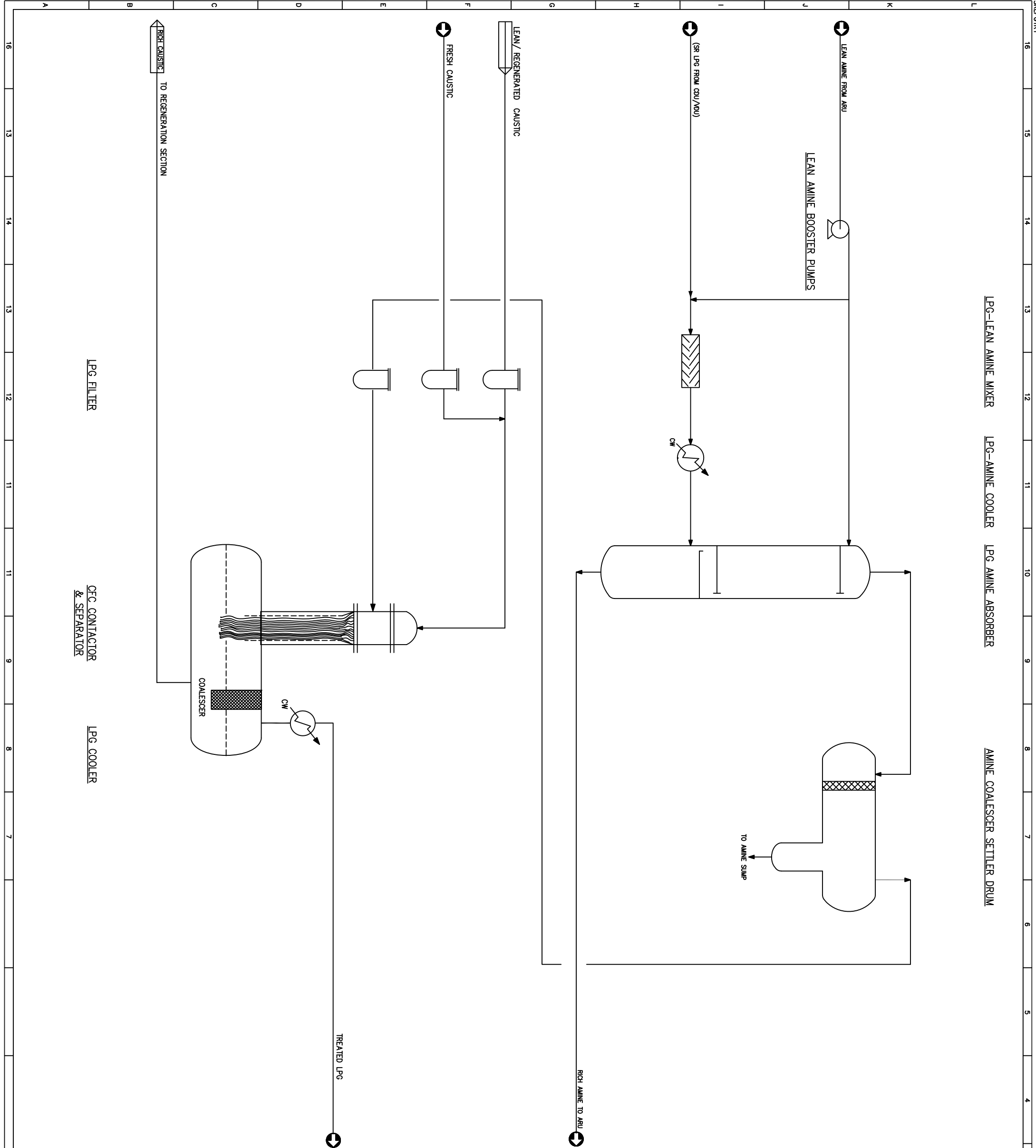
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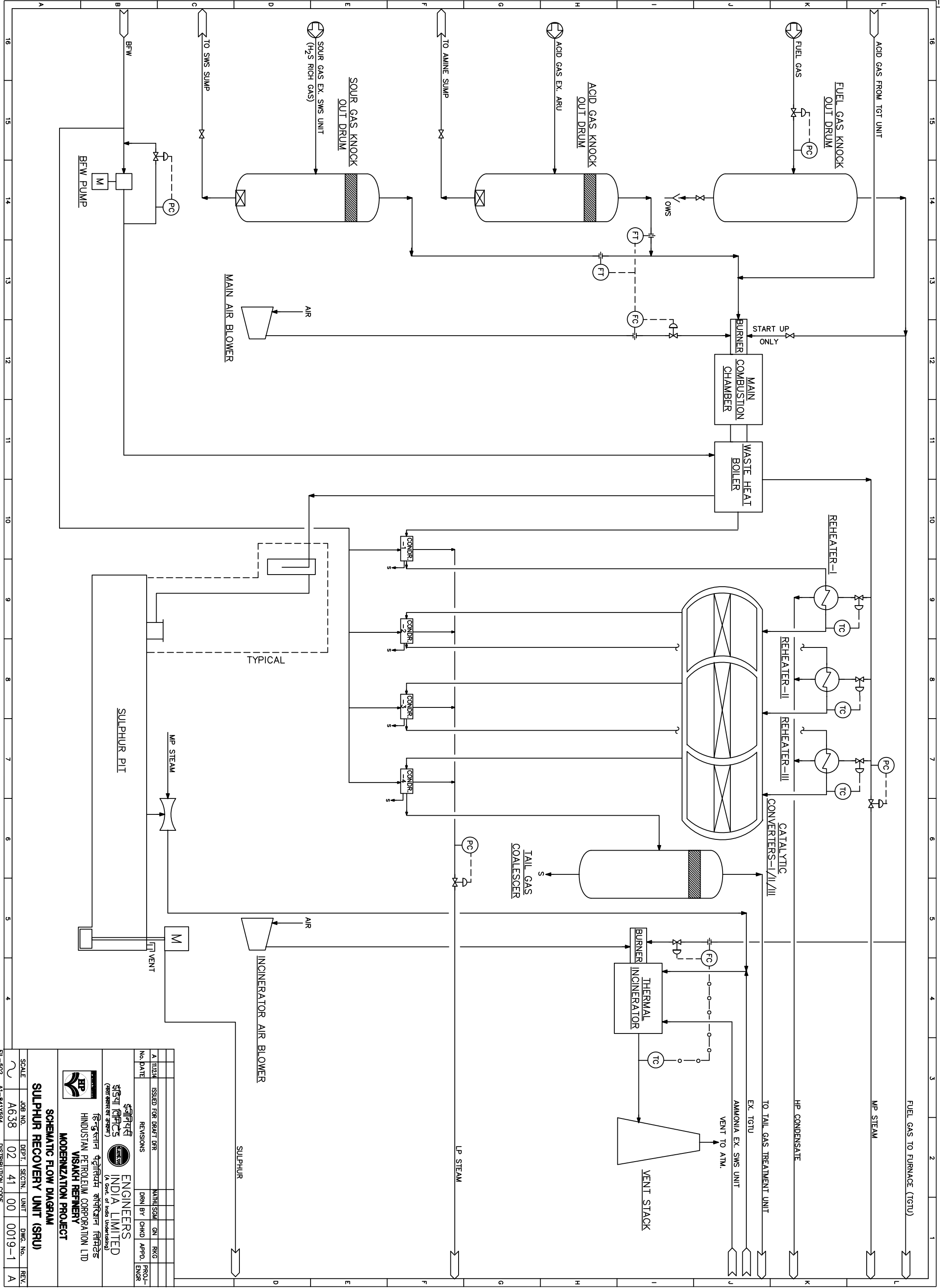


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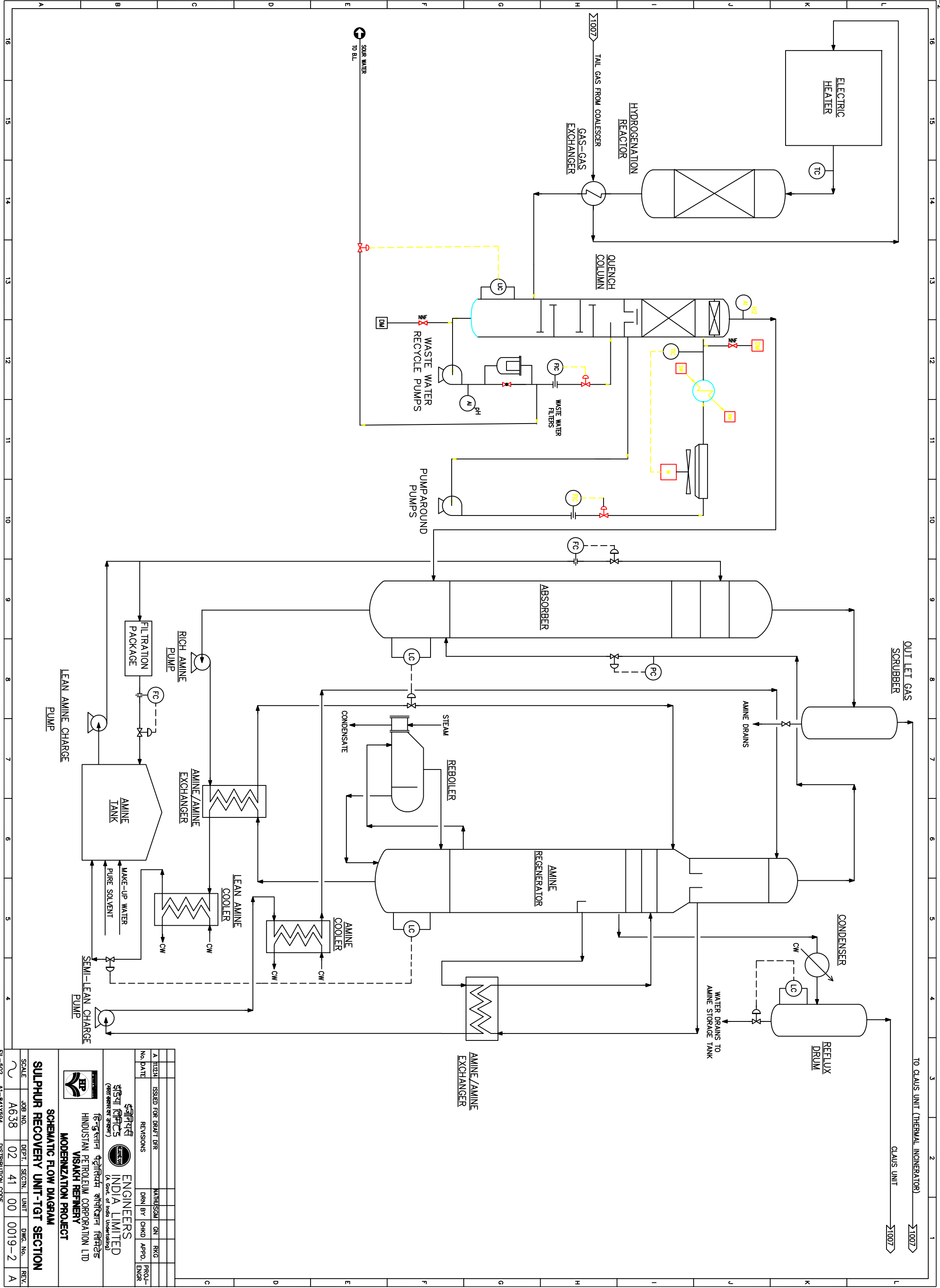


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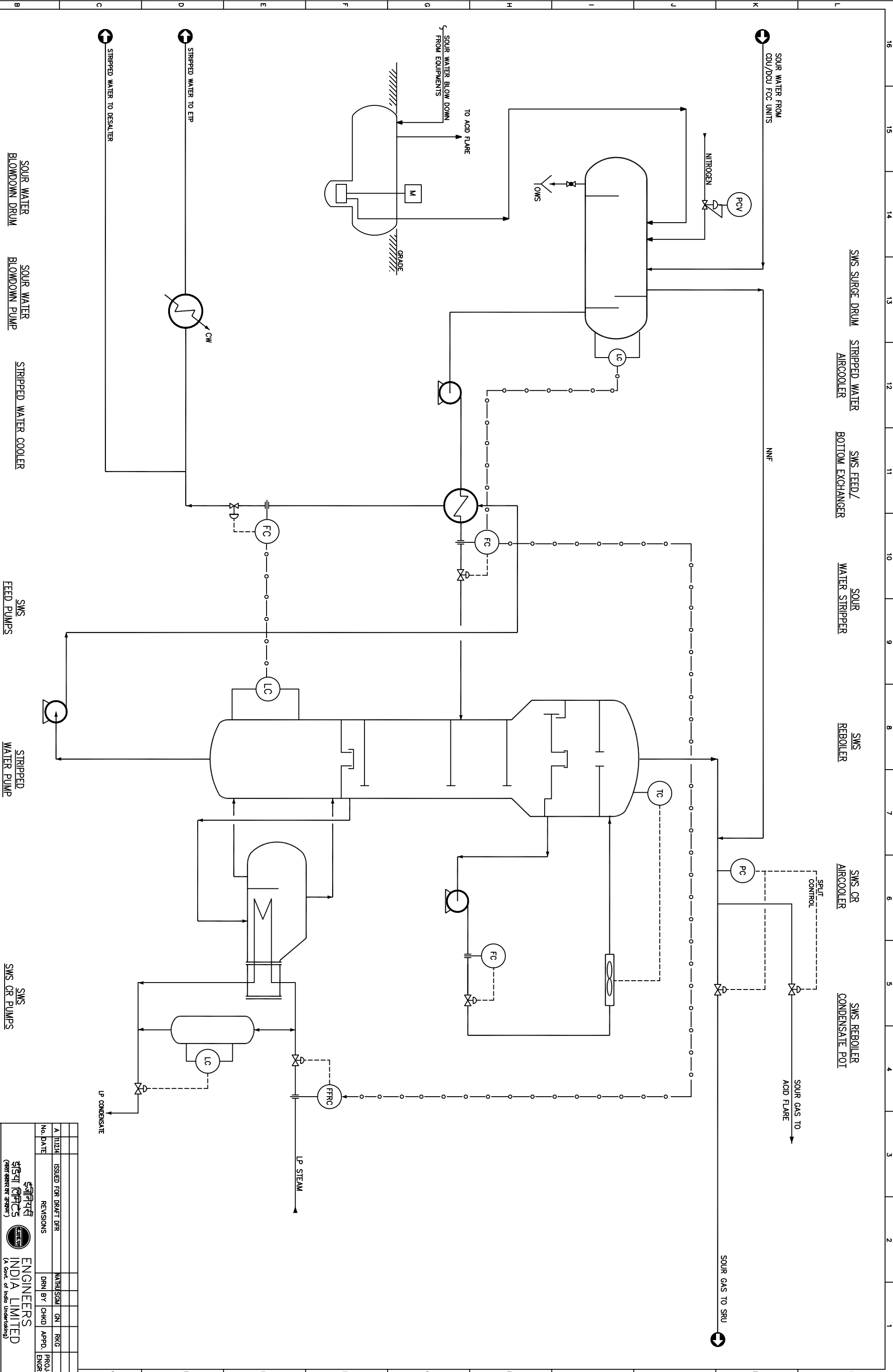
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SWS SURGE DRUM		STRIPPED WATER AIRCOOLER		SWS FEED/ BOTTOM EXCHANGER		SOUR WATER STRIPPER		SWS REBOILER		SWS CR AIRCOOLER		SWS REBOILER CONDENSATE POT	
SOUR WATER BLOWDOWN DRUM		SOUR WATER BLOWDOWN PUMP		STRIPPED WATER COOLER		SWS FEED PUMPS		STRIPPED WATER PUMP		SWS CR PUMPS		SOUR GAS TO ACID FLARE	
STRIPPED WATER TO ETP		STRIPPED WATER TO DESALTER		SOUR WATER BLOWDOWN PUMP		STRIPPED WATER COOLER		STRIPPED WATER PUMP		SWS CR PUMPS		SOUR GAS TO SRU	

SCHEMATIC FLOW DIAGRAM
REFINERY SOUR WATER STRIPPER UNIT (SWS-1)

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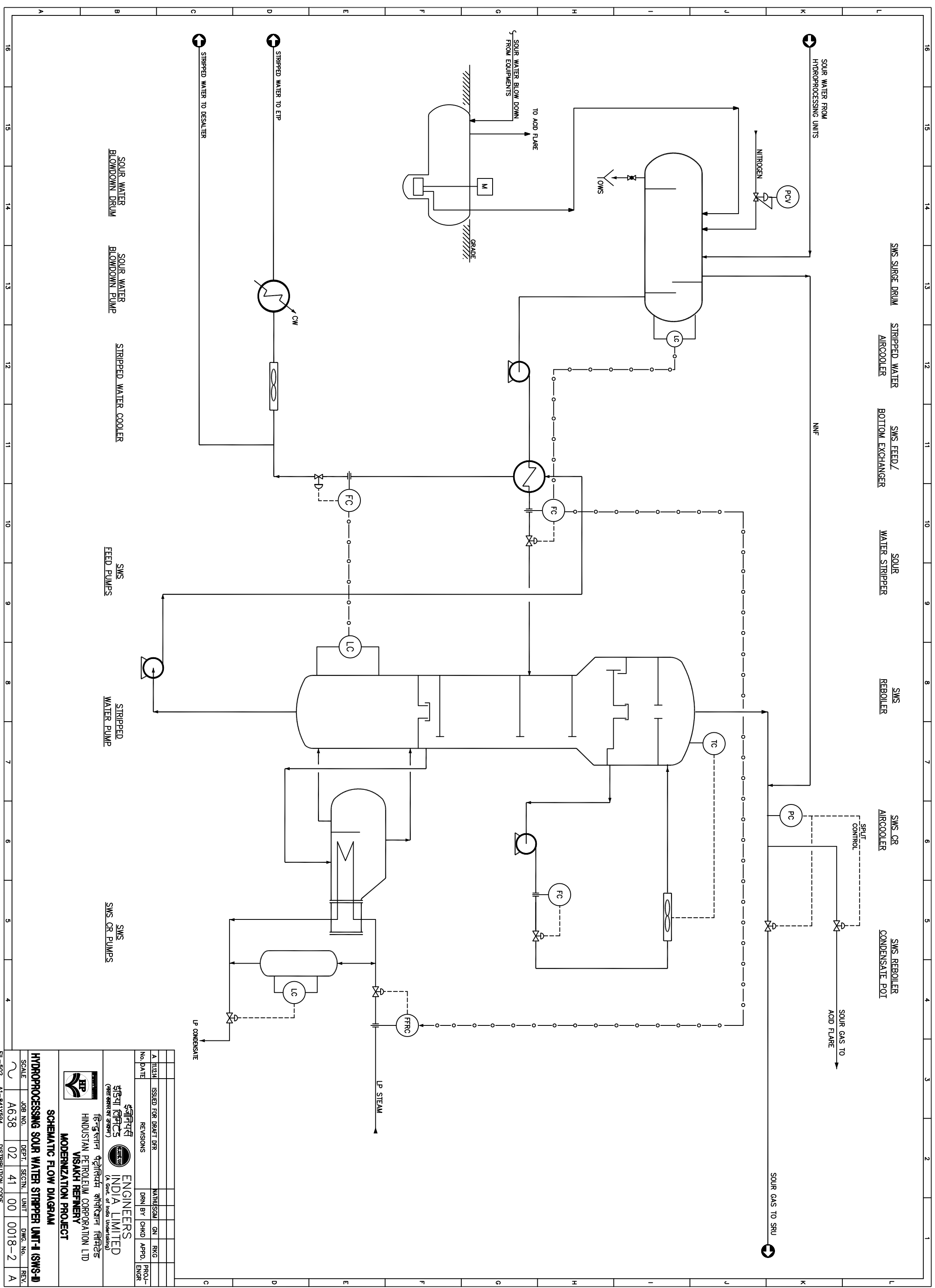
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7.6 OFFSITE SYSTEM

7.6.1 STORAGE AND TRANSFER SYSTEM

This section describes the storage and pumping facilities for feed/intermediate and finished product based on the material balance, unit capacities, block flow diagrams of refinery complex for the selected refinery configurations. Storage capacity is based on the process unit feed/ products rates, criticality of operation, emergency operation, catalyst regeneration/ replacement schedule etc.

The philosophy and facilities for storage and transfer is discussed below.

Offsite facilities are divided into three sections:

- Crude oil storage and transfer
- Intermediate Feed / Intermediate product storage and transfer
- Finished product storage

No augmentation has been considered in the crude receipt facilities. Tankage has been finalized based on Plot area available in refinery. Storage days for products and intermediate products have been worked out accordingly.

With the refinery capacity expansion, the products especially MS and HSD have increased appreciably. To facilitate expeditious evacuation of the products, the HPCL Marketing pipelines and associated distribution network system has to be capacity augmented suitably.

7.6.2 CRUDE OIL STORAGE AND TRANSFER

The tanks and pumps considered for selected cases are mentioned below.

- Existing refinery contains total 13 crude tanks out of which 5 crude tanks are inside refinery premises & 8 tanks are in ATP area
- Post VRMP, 2 crude tanks (120-T-01E & F) will not be available for crude service instead will be utilized for storing the VGO - FCC Feed
- Post VRMP, 1 crude tank (120-T-01C) will not be available for crude service instead will be utilized for storing the Raw water for VRMP.
- Besides the storage tanks, ISPRIL Crude cavern storage of 280,000 tons

(net pumpable capacity) is also considered for working out new crude storage tanks requirement.

- Post VRMP, refinery will have total 10 crude tanks, Out of which 2 crude Tanks at Refinery area and 8 crude tanks at ATP area.
- Two centrifugal pumps (1 Operating + 1 Standby) of rated capacity 1400 m³/hr will be provided for crude transfer from Crude tank to the new CDU-IV (Capacity 9 MMTPA), These pumps shall be designed for all design / check cases for CDU unit.
- Two centrifugal pumps (1 Operating + 1 Standby) of rated capacity 200 m³/hr will be provided for High Tan Crude Transfer from the crude tank at ATP area to the new CDU-IV.
- Crude pumping facilities at Refinery & ATP crude tank area to CDU-II & CDU-III shall be retained and piping facilities shall be integrated with the proposed new crude pump at ATP area such that it can be used for feeding CDU-IV also.
- Post VRMP pumping facility at ATP crude tank area shall feed all the three CDU's (Total 15 MMTPA), Integration of piping facilities for this to be carried out during detailed engineering.

Intermediate Feed Storage and Transfer

Following points are considered while allocating storage for intermediate streams:

- i. These tanks are provided to account for turnaround, interruption (including emergency), catalyst regeneration & replacement etc. Intermediate unit feed flow control will be within the respective unit battery limit. No controls are envisaged in the offsite area.
- ii. In case of heavy services, LVGO, HVGO, VBGO, VR, offsite piping shall be kept flushed when not in service. The light service pumps like light naphtha and LPG are to be considered for minimum flow bypass to avoid cavitation.
- iii. Typically three days storage for 100% unit operation has been considered for the intermediate tank.

7.6.3.1 Naphtha Hydro Treater (NHT) Unit Feed Storage and Transfer.

Existing tank 120-T-189 and tank 120-T-190 will be used for storing NHT feed post VRMP. However, swing service shall be provided for tank 120-T-15 (to be used for NHT / CCR / Prime-G feed) in view of one tank going for T&I. Existing feed transfer pump adequacy to be checked during detail engineering.

	Case A	Case B	Case C
Storage Cover (days)	3.8	3.8	3.8
Pump Capacity (M3/Hr)	Existing to be utilized	Existing to be utilized	Existing to be utilized

7.6.3.2 Solvent Deasphalting (SDA) feed storage and Transfer:

Vacuum Residue from existing and new CDUs goes to Solvent Deasphalting unit (SDA), and Bitumen Blowing unit (BBU). VBU and BBU are existing units and SDA is a new unit.

In present scenario, there is no tank for storing BBU feed and the same shall be followed post VRMP also.

For SDA feed, existing tanks 120-T-14A, 120-T-14B and 120-T-14C has been considered. No new tank is envisaged. The tanks 120-T-14A, 120-T-14B and 120-T-14C were earlier used for VBU feed. Service has been changed for these three tanks from VBU feed to SDA feed.

For SDA feed two new centrifugal pumps (one operating and one standby) have been considered.

	Case A	Case B	Case C
Storage Cover (days)	5.2	5.2	5.2
Pump Capacity (M3/Hr)	410	410	410

Pumping capacity has been calculated by taking design capacity of SDA (9300 TPD).

7.6.3.3 Slurry HCU (SHCU) Feed Storage and Transfer:

Slurry hydrocracker gets feed from SDA and FCC. For Slurry HCU feed, existing tanks 120-T-05 A, 120-T-05B, 120-T-06 and 120-T-06A shall be considered. No new tank is envisaged. All these tanks were Fuel oil tanks in the existing refinery. Since, post VRMP, fuel oil production has been decreased; hence, these tanks can be utilized for Slurry HCU Feed.

For SHC feed Two new centrifugal pumps (one operating and one standby) have been considered.

	Case A	Case B	Case C
Storage Cover(days)	6.8	6.8	6.8
Pump Capacity (M3/Hr)	365	365	365

Pumping capacity has been calculated by taking design capacity of SHCU (8250 TPD).

7.6.3.4 DHDS Feed Storage and Transfer

DHDS receives feed from CDU and FCCs. For DHDS feed, existing tanks 20-D-30, 20-D-31 and 20-D-32 shall be considered. Because of the space constraints no new tank is envisaged for DHDS feed storage. All these tanks shall be enabled for swing service so that these tanks can be used for DHDS feed as well as DHDT feed.

	Case A	Case B	Case C
Storage Cover (days)	3.23	3.23	3.23
Pump Capacity (M3/Hr)	Existing to be utilized	Existing to be utilized	Existing to be utilized

7.6.3.5 FCC Feed Storage and Transfer

The FCC unit receives feed from CDU, SHC. Since the Tank 20-D-3 and 20-D-4 will be dismantled to create space for installing new Hydrogen Unit of VRMP, Existing two number crude tanks 120-T-01 E& F will be utilised for VGO storage after necessary service change modification.

For FCC feed Three number new centrifugal pumps (two operating and one standby) have been considered.

	Case A	Case B	Case C
Storage Cover (days)	14.32	14.32	14.32
Pump Capacity (M3/Hr) (2W+1S)	200	200	200

Storage days& pumping capacity has been calculated by taking design capacity of FCC1 (3560 TPH) & FCC-II (2901 TPD).

7.6.3.6 Diesel Hydro treating Unit (DHDT) Feed Storage and Transfer

DHDT receives feed from CDU, FCCs and Slurry HCU. Post VRMP, there is revamp envisaged in DHDT. For DHDT feed, existing tanks 20-D-36 and 120-T-13 shall be considered. This gives storage for 1.7 days of unit operation. No new tank is envisaged. All these tanks shall be enabled for swing service so that these tanks can be used for DHDS feed as well as DHDT feed. Existing DHDT feed

pumps shall be utilised post VRMP also. Adequacy of pump for revamped condition shall be checked during detailed engineering.

	Case A	Case B	Case C
Storage Cover (days)	1.68	1.68	1.68
Pump Capacity (M3/Hr)	Existing to be utilized	Existing to be utilized	Existing to be utilized

7.6.3.7 CPP Naphtha Storage and Transfer

Naphtha is considered for firing in CPP. For CPP naphtha, existing tanks 120-T-185A, 120-T-185B, 120-T-185C , 120-T-187and 120-T-15 shall be considered. All these tanks are existing.

For start-up CPP diesel storage, existing tank 120-T-188 shall be utilised.

Swing service will be retained for tank 120-T-187to be used for CPP naphtha and VRMP HGU feed naphtha in view of one tank going for T&I. Existing CPP feed pumps shall be utilized post VRMP also.

	Case A	Case B	Case C
Storage Cover (days)	25	9	56
Pump Capacity (M3/Hr)	Existing to be utilized	Existing to be utilized	Existing to be utilized

7.6.3.8 HGU feed Storage and Transfer

Naphtha is considered as feed to HGU. For DHT HGU naphtha, existing tanks 20-D-120, 20-D-121& 120-T-186 (currently these are being used in Naphtha service) shall be considered.

For VRMP HGU naphtha, existing tank 20-D-60 and 20-D-61 shall be considered. Tank 120-T-186 will be enabled for HGU sweet naphtha feed for both DHT & VRMP HGU's.

Tank 120-T-187 will be enabled for HGU sweet naphtha feed for both DHT & VRMP HGU's and CPP. All these tanks are existing and no new tank is envisaged.

For DHDT HGU, existing feed pumps shall be utilised post VRMP also and for VRMP HGU Two number (1W + 1S) new feed pumps shall be considered.

	Case A	Case B	Case C
Storage Cover (days) -DHDT	4.9	4.9	4.9
Storage Cover (days)- VRMP	4.4	4.4	41
Pump Capacity (M3/Hr)	DHDT HGU : Existing to be utilized VRMP: New Pump of capacity 130 M3/Hr	DHDT HGU : Existing to be utilized VRMP: New Pump of capacity 130 M3/Hr	DHDT HGU : Existing to be utilized VRMP: New Pump of capacity 130 M3/Hr

7.6.3.9 CCR Feed Storage and Transfer

CCR receives feed from NHT. Post VRMP, there is 20 % revamp in CCR. For CCR feed, existing tanks 120-T-191 and 120-T-192 shall be considered. No new tank is envisaged. Existing pumps for CCR feed shall be utilised post VRMP also, Adequacy of pump for revamped condition shall be checked during detailed engineering.

	Case A	Case B	Case C
Storage Cover (days)	5.36	5.36	5.36
Pump Capacity (M3/Hr)	Existing to be utilized	Existing to be utilized	Existing to be utilized

7.6.3.10 Isomerate Storage and Transfer

Isomerate is the major product stream of ISOM Unit and is the main constituent for Gasoline blending. For Isomerate, existing tanks 120-T-193 and 120-T-194 shall be considered. No new tank is envisaged.

Existing pumps for Isomerate shall be utilised post VRMP also, Adequacy of pump for higher capacity shall be checked during detailed engineering.

	Case A	Case B	Case C
Storage Cover (days)	2.6	2.8	2.6
Pump Capacity (M3/Hr)	Existing to be utilized	Existing to be utilized	Existing to be utilized

7.6.3.11 Reformate Storage and Transfer

Reformate is the major product stream of CCR Unit and is the main constituent for Gasoline blending. For reformate, existing tanks 120-T-213 A and 120-T-213 B shall be considered. No new tank is envisaged.

Swing service will be retained for these tanks (to be used for reformate and MS product) in view of one tank going for T&I.

Existing pumps for Reformate shall be utilised post VRMP also, Adequacy of pump for revamped condition shall be checked during detailed engineering.

	Case A	Case B	Case C
Storage Cover (days)	11.2	11.2	11.2
Pump Capacity (M3/Hr)	Existing to be utilized	Existing to be utilized	Existing to be utilized

7.6.3.12 Naphtha Isomeration Feed Storage and Transfer

In present scenario, there is no intermediate tank for storing ISOM feed (as per Licensor's input) and the same shall be followed post VRMP also.

7.6.3.13 Prime-G Feed Storage and Transfer

Prime-G gets feed from the existing FCCs. Post VRMP Prime-G will be under-utilized. For Prime-G, tank 20-D-151 shall be considered. No new tank is envisaged.

In tank 20-D-151 service will be changed from FO to prime G. No of days have been calculated considering design capacity of prime G. Adequacy of pump for service change condition shall be checked during detailed engineering.

	Case A	Case B	Case C
Storage Cover (days)	2	2	2
Pump Capacity (M3/Hr)	Existing to be utilized	Existing to be utilized	Existing to be utilized

7.6.3.14 Full Conversion Hydrocracker feed Storage and Transfer

Three existing tanks i.e. 20-D-90, 20-D-157 and 20-D-80 shall be considered for FC-HCU feed tanks. Currently 20-D-90 & 20-D-157 are used for storing cutter stock and 20-D-80 for storing FO. No new tank is envisaged. Tanks compatibility need to be checked during detail engineering.

Two new centrifugal pumps (one operating and one standby) have been considered.

	Case A	Case B	Case C
Storage Cover (days)	3.4	3.3	3.4
Pump Capacity (M3/Hr)	475	475	475

Pumping capacity has been calculated by taking design capacity of FCHCU (9900 TPD).

7.6.3.15 Flushing oil Storage and Transfer

Existing flushing oil storage and pumping facilities shall be utilised post VRMP also. However, the adequacy of the pumping facility post VRMP need to be checked for post VRMP.

7.6.3.16 Wet Slop/ Dry slop Storage and Transfer

Existing wet and dry slop storage facilities shall be utilised post VRMP also. No new tank has been provided for this service because of plot area limitation.

Existing pumping facilities shall be used for wet slop and dry slop transfer post VRMP also.

Slop Tanks
120T-207A
120T-207B
120T-208A
120T-208B
20-D-09
120-T-10A
120-T-10B
120-T-10C
120-T-11A
120-T-11B
120-T-11C
20-D-13
20-D-11
20-D-12
20-D-14

7.6.4 FINISHED PRODUCT STORAGE AND TRANSFER PHILOSOPHY

Finished product tankage for naphtha, MS, ATF, SKO, HSD, Fuel oil in the refinery has been designed considered for production cover of minimum 15days (Except LPG/Propylene/Naphtha). Details of the individual finished product storage facilities are given below.

7.6.4.1 LPG Storage:

Existing 5number bullets 121-T-01 A, 121-T-01 B, 121-T-01C, 121-T-01D and 121-T-01 E shall be used for LPG storage.

	Case A	Case B	Case C
Storage Cover (days)	2.6	2.7	2.6

The LPG product has to be evacuated from refinery at a faster rate considering the increased LPG production and limited storage. No additional bullets are considered as there is a restriction on storage put in by State PCB.

7.6.4.2 Propylene Storage and Transfer

Existing 2 number bullets 121-T-02 A and 121-T-02 B shall be used for propylene storage.

	Case A	Case B	Case C
Storage Cover (days)	3.9	4	3.82

7.6.4.3 Naphtha Storage and transfer

Two existing tanks 20-D-160 and 20-D-161 will be used for Naphtha storage. Naphtha production in Total power generation case is Nil so in that scenario naphtha tanks 20-D-160 & 20-D-161 can be utilized for swing services in HGU or CPP Feed.

	Case A	Case B	Case C
Storage Cover (days)	21.6	-	5

7.6.4.4 BS (IV/V) MS Storage and Transfer

Existing tanks 120-T-04, 120-T-203 A, 120-T-203 B, 120-T-203 C, 120-T-206A, 120-T-206B & 120-T-205A will be used as BS (IV/V) MS storage. Any two tanks can be utilized for storing BS (V) grade MS based on VVSPL cycle length evaluated for dispatching BS (V) after VVSPL capacity augmentation. Pump adequacy to be checked during detail engineering.

	Case A	Case B	Case C
Storage Cover (days)	19.6	19.8	19.6
Pump Capacity (M3/Hr)	Existing to be utilized	Existing to be utilized	Existing to be utilized

7.6.4.5 ATF Storage and Transfer

In all the three cases, existing tank 120-T-204 B and 120-T-204 C will be used as ATF storage. This provides total storage sufficient for 187 days of ATF production in all the cases. No new tank is envisaged in ATF service. When any tank is under maintenance then any SKO tank can be used in ATF/SKO swing service.

7.6.4.6 SKO Storage and Transfer

In all the four cases, existing tanks 120-T-204 A, 120-T-205 B and 120-T-210 will be used for SKO storage. This provides total storage sufficient for 15 days of SKO production. No new tank is envisaged in SKO service.

7.6.4.7 BS IV/V Diesel Storage and Transfer

Existing tanks 120-T-202 A, 120-T-202 B, 120-T-202 C, 120-T-209 A, 120-T-209 B, 120-T-211 and 120-T-214 will be used as BS IV/VHSD storage.

In addition to the existing tanks, eight number new tanks of capacity 40,000M3 each and two number tanks of capacity 23529 M3 each have been considered at ATP area. Any 6-7 tanks could be used for storing BS V grade diesel based on VVSPL cycle length for BS V after VVSPL capacity augmentation. This provides total storage sufficient for 15 days of BS IV/V Diesel production. Existing pump adequacy to be checked during detail engineering.

7.6.4.8 Bitumen storage and Transfer

Existing tanks 20-D-34, 20-D-35, 500-T-001 and 500-T-002 will be used as storage for Bitumen. Existing tanks 23-D-10 and 20-D-154 will be dismantled post VRMP. No new tank is envisaged for this service. This provides total storage sufficient for 25 days of bitumen production in all cases.

Existing pumping facilities of bitumen shall be utilized for bitumen products transfer post VRMP also. Adequacy of bitumen pumps for shall be checked during detailed engineering.

7.6.4.9 Slurry Pitch Disposal

Slurry pitch which is residual from the SHCU has a high energy content stream with residual material and feedstock metals. Slurry pitch generation is a viscous liquid which can be solidified and converted into transportable granules. Slurry pitch can be considered as economical alternative fuel because of its controlled properties and ease of bulk handling. There are various value upgrading options for slurry pitch. The options where Slurry pitch can be utilized are as follows:

- Solidification of liquid pitch by Belt Conveyor SANDVIK: Solidification by indirect water cooled conveyor belt followed by simple finger crushing unit.
- Solidification of liquid pitch by Extrusion Process of Rutgers: A mixture of steam and water, adjusted to a certain temperature, will be added to the liquid pitch - stream in a nozzle, cooling the pitch down to a moderate solidification temperature.
- Cement Industry: Slurry pitch in the form of solid can be co-fired with coal at up to 30 wt% of the fuel requirement in the cement kilns. Since India

has a large demand for low fuel source for its relatively large Cement industry, this market should be an attractive option for slurry pitch utilisation.

7.6.4.10 Fuel Oil Storage and Transfer

Existing tanks 20-D-37 and 20-D-38 will be used as storage for Fuel Oil. This provides total storage sufficient for 37.6 days of fuel oil production. No new tank is envisaged for this service.

7.6.4.11 MTO storage and transfer

Existing tanks 20-D-122 and 20-D-123 will be used as storage for MTO.

7.6.4.12 LDO storage and transfer

Existing tanks 20-D-33 and 20-D-70 will be used as storage for LDO. This provides total storage sufficient for 95.6 days of LDO production. No new tank is envisaged for this service.

7.6.4.13 Others

- Existing tanks 120-T-16A, 120-T-16B and 20-D-124 will be used as storage for JBO.
- Existing tanks 20-D-140 and 20-D-141 will be used as storage for LSHF HSD.
- Existing tanks 120-T-212 will be used as storage for HCN Pipe Line Plug Material.
- Existing tanks 20-D-143, 20-D-144 and 20-D-153 will be used as storage for cutter stock. Since FO production is Nil (172 KTPA as one of the cases), so two tanks will be retained as cutter stock for FO & third tank will be used as LCO Cutter Stock tank for IFO.
- Existing Tanks 401-T-101 & 401-T-102 will be retained in IFO service. One FO tank 20-D-150 has also been taken in IFO service.

The following is the list of new tanks considered for VRMP:

TABLE:7.6.1 LIST OF NEW CRUDE/PRODUCT TANKS

Sl. No.	Service	No. Of Tanks	Diameter (m)	Height (m)	Operating Temp °C	Design temp °C	Thickness (m)	Pressure Rating #	Weight of Tank (Kg)	Type	Class	Liquid Stored Capacity (m3)
1	Diesel tank	8	53	20	Amb.	65	0.045	150	1302223	Floating	A	40000
2	Diesel tank	2	41	20	Amb.	65	0.03	150	547900	Floating	B	23529

Table: 7.6.2 Following is the list of offsite pumps considered for VRMP:

List of Offsite Pumps							
S. No.	Pump Description	Numbers	Flow (m3/hr)	Head (m)	MOC	TYPE	Motor Rating (KW)
1.	CRUDE PUMP	1W + 1 S	1400	160	CS	Centrifugal	415
2.	HIGH TAN CRUDE PUMP	1W + 1 S	200	160	CS	Centrifugal	115
3.	SDA FEED PUMP	1W + 1 S	410	140	CS	Centrifugal	250
4.	HCU FEED PUMP	1W + 1S	475	150	CS	Centrifugal	285
5	SHC FEED PUMP	1W +1S	365	150	CS	Centrifugal	240
6	HYDROGEN FEED PUMP	1W + 1 S	130	150	CS	Centrifugal	55
7	FCC FEED PUMP	2W + 1 S	200	160	CS	Centrifugal	90

Table: 7.6.3 Following are the list of existing tanks with their modified service post VRMP.

S.No	Service		Tank No.s	Class		Location	Type	Dia	Ht	Net pumpable Capacity
	Existing	Modified		Existing	Modified					
1	Crude	Raw Water	120-T-01C	A	A	Refinery	Floating	79	13.5	51427
2	Crude	Crude	120-T-01D	A	A	Refinery	Floating	79	13.6	29387
3	Crude	FCCU Feed	120-T-01E	A	C	Refinery	Floating	79	13.5	51474
4	Crude	FCCU Feed	120-T-01F	A	C	Refinery	Floating	79	13.5	48007
5	Crude	Crude	20-D-05	A	A	Refinery	Floating	79	13.6	49899
6	Crude	Crude	120-T-201A	A	A	ATP	Floating	79	14.4	49661
7	Crude	Crude	120-T-201B	A	A	ATP	Floating	79	14.4	49661
8	Crude	Crude	120-T-201 G	A	A	ATP	Floating	70	14.4	39250
9	Crude	Crude	120-T-201D	A	A	ATP	Floating	79	14.4	49661
10	Crude	Crude	120-T-201E	A	A	ATP	Floating	79	14.4	51230
11	Crude	Crude	120-T-201F	A	A	ATP	Floating	79	14.4	51230
12	Crude	Crude	120-T-201 H	A	A	ATP	Floating	70	14.4	39250
13	Crude	Crude	120-T-201C	A	A	ATP	Floating	79	14.4	49661
14	NA	Crude	ISPRL	A	A					

PRODUCT TANKS

S.No	Service		Tank No.s	Class		Location	Type	Dia Mtr	Ht Mtr	Net Pumpable Capacity M3
	Existing	Modified		Existing	Modified					
1	Propylene	Propylene	121-T-02 A	A	A	Refinery	Mounted Bullet	5	50	1143
2	Propylene	Propylene	121-T-02 B	A	A	Refinery	Mounted Bullet	5	50	1152
3	LPG	LPG	121-T-01 A	A	A	Refinery	Mounted Bullet	7	70	1699
4	LPG	LPG	121-T-01B	A	A	Refinery	Mounted Bullet	7	70	1698
5	LPG	LPG	121-T-01 C	A	A	Refinery	Mounted Bullet	7	70	1684
6	LPG	LPG	121-T-01 D	A	A	Refinery	Mounted Bullet	7	70	1684
7	LPG	LPG	121-T-01 E	A	A	Refinery	Mounted Bullet	7	70	1684
8	NAPHTHA /MS	NAPHTHA	20-D-160	A	A	Refinery	Floating	33.5	14.6	9265
9	NAPHTHA /MS	NAPHTHA	20-D-161	A	A	Refinery	Floating	33.5	14.6	8840
10	MS	MS (IV + V)	120 - T - 04	A	A	Refinery	Floating	42.5	13.5	14187
11	NAPHTHA /MS	MS (IV + V)	120-T-203 A	A	A	ATP	Floating	61	14.4	30468
12	NAPHTHA /MS	MS (IV + V)	120-T-203 B	A	A	ATP	Floating	61	14.4	30527
13	MS	MS (IV + V)	120-T-203 C	A	A	ATP	Floating	61	14.4	30468
14	MS	MS (IV + V)	120-T-205 A	A	A	ATP	Floating	50	14.4	21610
15	MS	MS (IV + V)	120-T-206 A	A	A	ATP	Floating	50	14.4	21610
16	MS	MS (IV + V)	120-T-206 B	A	A	ATP	Floating	50	14.4	21531
17	Kero	Kero	120 - T -204 A	B	B	ATP	Floating	40	14.4	13450
18	Kero	Kero	120 - T - 205 B	B	B	ATP	Floating	40	14.4	13482
19	Kero	Kero	120 - T -210	B	B	ATP	Floating	40	14.4	12570
20	ATF	ATF	120 - T -204 B	B	B	ATP	Floating cum fixed	40	14.4	10911
21	ATF	ATF	120 - T -204 C	B	B	ATP	Floating cum fixed	40	14.4	10798

S.No	Service		Tank No.s	Class		Location	Type	Dia	Ht	Net Pumpable Capacity
	Existing	Modified		Existing	Modified					
22	HSD	HSD (IV + V)	120-T-202 A	B	B	ATP	Floating	61	14.4	31404
23	HSD	HSD (IV + V)	120-T-202 B	B	B	ATP	Floating	61	14.4	31345
24	HSD	HSD (IV + V)	120-T-202 C	B	B	ATP	Floating	61	14.4	31404
25	HSD	HSD (IV + V)	120-T-209 A	B	B	ATP	Floating	54	14.4	10992
26	HSD	HSD (IV + V)	120-T-209 B	B	B	ATP	Floating	54	14.4	17862
27	HSD	HSD (IV + V)	120 - T - 211	B	B	ATP	Floating	54	14.4	31558
28	HSD	HSD (IV + V)	120-T-214	B	B	ATP	Floating	60	14.4	30521
29	FO	FO	20-D-37	C	C	Refinery	Fixed	33.5	14.6	9693
30	FO	FO	20-D-38	C	C	Refinery	Fixed	33.5	14.6	9693
31	Bitumen	Bitumen	20-D-34	D	D	Refinery	Cone Roof	24.4	14.6	5844
32	Bitumen	Bitumen	20-D-35	D	D	Refinery	Cone Roof	24.4	14.6	5844
33	Bitumen	Dismantled	23-D-10	D	D	Dismantled				
34	Bitumen	Dismantled	20-D-154	D	D	Dismantled				
35	Bitumen	Bitumen	500-T-001	D	D	Refinery	Cone Roof	18	12	2286
36	Bitumen	Bitumen	500-T-002	D	D	Refinery	Cone Roof	18	12	2286
37	SOUR NAPHTHA/MTO	MTO	20-D-122	A		Refinery	Floating	9.2	12	493
38	JBO/MTO	MTO	20-D-123	B	B	Refinery	Floating	9.2	12	558
39	LDO	LDO	20-D-33	B	B	Refinery	Cone Roof	22.4	14.6	5691
40	LDO/SOUR DSL/CUTTER STOCK	LDO	20-D-70	B	B	Refinery	Fixed	21.3	12.2	3776
41	JBO/SOUR DSL	JBO	120-T-16A	B	B	Refinery	Cone Roof	17.5	14.6	2769
42	JBO/SOUR DSL	JBO	120-T-16B	B	B	Refinery	Cone Roof	17.5	14.6	2769
43	JBO	JBO	20-D-124	B	B	Refinery	Floating	12.2	12.2	558
44	HFHSD	LSHF HSD	20-D-140	B	B	Refinery	Fixed	20	13	3776
45	LDO/HFHSD	LSHF HSD	20-D-141			Refinery	Fixed	21.3	12.2	3506
46	HCN Pipe Line Plug Material/SKO	HCN Pipe Line Plug Material	120 - T - 212	A	A	ATP	Floating	40	14.4	13450

S.No	Service		Tank No.s	Class		Location	Type	Dia	Ht	Net Pumpable Capacity
	Existing	Modified		Existing	Modified					
								Mtr	Mtr	M3
1	Cutter Stock	Cutter Stock	20-D-143	B	B	Refinery	Cone Roof	12.1	18.2	2219
2	Cutter Stock	Cutter Stock	20-D-144	B	B	Refinery	Cone Roof	12.2	18.3	2219
3	Cutter Stock	Cutter Stock	20-D-153	B	B	Refinery	Cone Roof	8.5	15.2	838
6	SOUR NAPHTHA	HGU Feed Naphtha DHT	20-D-120	A	A	Refinery	Floating	9.2	12.2	493
7	SOUR NAPHTHA	HGU Feed Naphtha DHT	20-D-121	A	A	Refinery	Floating	9.2	12.2	493
8	SWEET NAPHTHA	HGU Feed Naphtha DHT	120-T-186	A	A	Refinery	Floating cum Fixed	18	14.4	1653
9	NAPHTHA /MS	HGU Feed Naphtha VRMP	20-D-60	A	A	Refinery	Floating	27.4	14.6	5908
10	NAPHTHA /MS	HGU Feed Naphtha VRMP	20-D-61	A	A	Refinery	Floating	27.4	14.6	5908
11	CPP Naphtha	CPP Naphtha	120-T-185A	A	A	Refinery	Floating cum Fixed	18	14.4	1907
12	CPP Naphtha	CPP Naphtha	120-T-185B	A	A	Refinery	Floating cum Fixed	18	14.4	1907
13	CPP Naphtha	CPP Naphtha	120-T-185C	A	A	Refinery	Floating cum Fixed	18	14.4	1907
14	CPP Naphtha	CPP Naphtha	120-T-187	A	A	Refinery	Floating cum Fixed	18	14.4	1907
15	NAPHTHA	CPP Naphtha	120-T-15	A	A	Refinery	Floating	27	14.6	5244
16	CPP HSD (INT FUEL)	CPP HSD	120-T-188	B	B	Refinery	Floating	18	12	1908
17	NHT FEED	NHT FEED	120-T-189	A	A	Refinery	Floating / Fixed with N2 BKT	40	14.9	11309

S.No	Service		Tank No.s	Class		Location	Type	Dia	Ht	Net Pumpable Capacity
	Existing	Modified		Existing	Modified					
18	NHT FEED	NHT FEED	120-T-190	A	A	Refinery	Floating cum Fixed	42.5	16	12766
20	CCR FEED	CCR FEED	120-T-191	A	A	Refinery	Floating cum Fixed	33.5	16.1	7477
21	FCCNHT FEED	CCR FEED	120-T-192	A	A	Refinery	Floating cum Fixed	42.5	14.9	12056
22	ISOMERATE	ISOMERATE	120-T-193	A	A	Refinery	Dome	20	18	2671
23	ISOMERATE	ISOMERATE	120-T-194	A	A	Refinery	Dome	20	14.2	2671
24	REFORMATE	REFORMATE	120-T-213A	A	A	ATP	Floating	44	14.4	16720
25	REFORMATE	REFORMATE	120-T-213B	A	A	ATP	Floating	44	14.4	16720
26	SOUR DSL	DHDT FEED	20-D-36	B	B	Refinery	Floating Cum Fixed	30.5	13.9	6908
27	SOUR DSL	DHDT FEED	120-T-13	B	B	Refinery	Floating	33.5	14.6	8812
28	SOUR DSL	DHDS FEED	20-D-30	B	B	Refinery	Floating Cum Fixed	33.5	14.6	8805
29	SOUR DSL	DHDS FEED	20-D-31	B	B	Refinery	Floating Cum Fixed	33.5	14.6	9717
30	SOUR DSL	DHDS FEED	20-D-32	B	B	Refinery	Floating Cum Fixed	33.5	14.6	8834
31	WET SLOP	WET SLOP	120-T-11A	D	D	Refinery	Fixed	7.5	6	
32	WET SLOP	WET SLOP	120-T-11B	D	D	Refinery	Fixed	7.5	6	
33	WET SLOP	WET SLOP	120-T-11C	D	D	Refinery	Fixed	7	5.2	
34	WET SLOP	WET SLOP	120-T-208A	D	D	ATP	Fixed	40	14.4	250
35	WET SLOP	WET SLOP	120-T-208B	D	D	ATP	Fixed	40	14.4	250
36	WET SLOP	WET SLOP	20-D-13	D	D	Refinery	Cone Roof	7.3	6.1	
37	WET SLOP	WET SLOP	20-D-14	D	D	Refinery	Cone Roof	7.3	6.1	
38	DRY SLOP	DRY SLOP	120-T-10A	D	D	Refinery	Floating	14	12	1000

S.No	Service		Tank No.s	Class		Location	Type	Dia	Ht	Net Pumpable Capacity
	Existing	Modified		Existing	Modified					
								Mtr	Mtr	M3
39	DRY SLOP	DRY SLOP	120-T-10B	D	D	Refinery	Floating	14	12	1000
40	WET SLOP	WET SLOP	120-T-10C	D	D	Refinery	Floating	14	11	
41	DRY SLOP	DRY SLOP	20-D-11	D	D	Refinery	Fixed	12.2	9.1	420
42	WET SLOP	WET SLOP	20-D-12	D	D	Refinery	Fixed	9.1	12.2	
43	DRY SLOP	DRY SLOP	120-T-207A	D	D	ATP	Floating	12	10.5	763
44	DRY SLOP	DRY SLOP	120-T-207B	D	D	ATP	Floating	40	14.4	763
45	WET SLOP	WET SLOP	20-D-09	D	D					510
46	HOTWELL OIL	HOTWELL OIL	120-T-17	B	B	Refinery	Floating	17.5	14.6	2042
47	FCCU FEED	Dismantled	20-D-3	C	C					
48	FCCU FEED	Dismantled	20-D-4	C	C					
49	VBU Feed	SDA FEED	120-T-14A	C	C	Refinery	Cone Roof	33.5	20	14991
50	VBU Feed	SDA FEED	120-T-14B	C	C	Refinery	Cone Roof	33.5	20	14991
51	VBU Feed	SDA FEED	120-T-14C	C	C	Refinery	Cone Roof	33.5	20	14991
52	FO Tank	SHCU FEED	120-T-05A	C	C	Refinery	Fixed	34.5	14	10271
53	FO Tank	SHCU FEED	120-T-05B	C	C	Refinery	Fixed	34.5	14	10271
54	LSHS Tank	SHCU FEED	120-T-06A	C	C	Refinery	Fixed	40	12.9	13814
55	LSHS Tank	SHCU FEED	120-T-06	C	C	Refinery	Fixed	40	12.9	12558
56	FO/LSHS Tank	IFO	20-D-150	C	C	Refinery	Fixed	24.4	14.6	5610
57	FO/LSHS Tank	Prime G	20-D-151	C	A	Refinery	Fixed	24.4	14.6	5610

S.No	Service		Tank No.s	Class		Location	Type	Dia	Ht	Net Pumpable Capacity
	Existing	Modified		Existing	Modified					
								Mtr	Mtr	M3
58	FO Tank	HCU FEED	20-D-90	C	C	Refinery	Fixed	33.5	14.6	12805
59	FO Tank	HCU FEED	20-D-157	C	C	Refinery	Fixed	36.6	12.2	11572
60	Sour Diesel	HCU FEED	20-D-80	B	C	Refinery	Fixed with N2 Blanketting	34	12.9	9241
61	IFO	IFO	401-T-101	C	C	Refinery	Fixed			
62	IFO	IFO	401-102	C	C	Refinery	Fixed			

7.5 FLARE SYSTEMS

The flare system will be provided for safe disposal of combustible, toxic gases which, are relieved from process plants and off sites during start - up, shutdown, normal operation or in case of an emergency such as:

- Cooling water failure
- General Power failure
- Any other operational failure
- Blocked outlet
- Reflux failure
- Local power failure
- Tube rupture
- External fire

Under Visakh Refinery Modernization Project flare load shall be generated from new process units i.e. Crude distillation unit, Full Conversion Hydrocracker / Once through hydrocracker, Slurry Hydrocracker, Solvent Deasphalting Unit, Alkylation Unit, Hydrogen generation Unit, SRU(with TGT), ARU, SWS-I, SWS-II, FG ATU,LPG Caustic wash Units and New off-site facilities. Existing units flare load in post revamp scenario shall be checked during detailed engineering for routing to existing flare system. The relief load from various units shall be segregated into hydrocarbon flare & sour flare. One for Hydrocarbon flare for process units and the other for the sulphur block handling acid flare.

The existing refinery has in place two flare systems

VREP II: 698.5 TPH (HC flaring), 13 TPH (Acid Gas Flaring)

VRCFP: 491 TPH (HC flaring), 15 TPH (Acid Gas Flaring)

36" stub and 14" stub were available in VRCFP hydrocarbon and Acid Gas flare headers respectively. The 48" hydrocarbon flare header and 18" Acid Gas flare

header from the DHT facilities were connected to the available stubs of VRFCF flare system.

The pipe track and civil foundation under DHT project which carries the flare header is designed for carrying additional flare headers of 68” hydrocarbon header and 32” Acid Gas header.

No new flare considered for DHT project.

For VRMP load new flare system has been considered and it will be independent from the existing flare system.

The new Demountable flare will be located near to the VREP – I flare which is going to be dismantled .The maximum stack height for the Refinery flares is governed by limits specified by the Aviation Authority.

De-mountable Flare system:

De-mountable flare system where numbers of flare stacks are mounted on a common derrick structure, wherein each flare stack shall be de-mounted independently with other flare stacks are operating. Demountable Flare system is considered because:

- De-mountable flare can be considered wherein there are different type of flares envisaged in same complex i.e. Normal flare, Cryogenic flare, Sour flare and any process specific flare etc.
- De-mountable flare can also be considered based on shut down grouping of process units, so that any particular shutdown grouping the flare tip can be maintained without affecting the other process units and flare (Complete shutdown of process unit is not required for flare related maintenance)
- Number of flare stacks in a common structure reduces the plot area.
- In De-mountable flare, risers are made in number of pieces, which avoids the requirement of heavy cranes.
- Workers’ can’t work at high elevations with a flare stack in service due to radiation concerns , so after demounting the flare any maintenance work can be carried out. Demountable lower the stack instead of raising the worker.
- De-mountable flare with staging will also save fuel consumption, where normally a small flare can be considered and for peak load one or two more flare stacks

can be considered. By this fuel gas purging requirement in the peak flare can be avoided.

7.5.1 FLARE LOADS

The flare load from each of the new units for different failure scenarios are estimated based on in-house data. These shall be further verified once the licensor data for the new facilities is available.

The flare loads from individual units are segregated into two categories i.e. Hydrocarbon and Sour.

The governing flare load for VRMP is given below.

7.5.2 HYDROCARBON FLARE

- Estimated load = 880,000[#] kg/hr.
- Controlling case = Complex Power failure

Following Cases will be studied for calculating HC flare loads:

Flare Load considered is preliminary estimations based on in-house data and required to be confirmed during detail engineering.

Cooling water failure

Two independent cooling towers are envisaged for the refinery project. With the segregation of cooling water supply source, the safety relief loads for cooling water failure of one part of the refinery units shall not be additive to the cooling water failure load of rest of the refinery.

Unit Power failure and Total complex power failure

During General power failure, only the equipment which is connected with emergency power supply shall run. So, individual unit power failure loads are additive.

7.5.3 SOUR FLARE LOADS

Sour flare

- Estimated load = 50700[#] kg/hr.
- Controlling case = Fire Case

Flare Load considered is preliminary estimations based on in house data and are required to be confirmed during detail engineering.

The flare loads from individual units (SRU/TGTU, SWS AND ARU) for following cases will be studied.

- Cooling water failure
- Local Power Failure in Sulphur block / Reflux failure in ARU, SWS
- SRU shutdown
- Fire Case

7.5.4 FLARE HEADER

There shall be two separate flare headers, one carrying the hydrocarbon flare relief, second handling Sour flare relief from Sulphur block. The main hydrocarbon flare header shall cater to collect relief from CDU/VDU-IV, HCU/OHCU, SHC, SDA, and Alkylation Unit, HGU unit, LPG treating Unit and Fuel gas amine treating Unit. Revamp load from existing units shall be routed to existing flare. Adequacy of existing Flare System shall be checked during detail design as per licensor design data. The sour flare header will cater to relief from SRU, SWS and ARU units.

7.5.5 KNOCK-OUT DRUM

Individual flare KOD is provided within each process unit battery limit. In addition, a common HC flare knockout drum (KOD) shall be provided near the flare stack. The knock drum shall be provided with ~30 minutes liquid hold up by considering

3-5 % liquid entrainment in HC vapor & to account for condensation due to vapor cooling.

For sour flare relief there will be a main knock out drum in the HC flare stack area and another common KOD shall be provided in Sulphur block ISBL common for SRU, SWS & ARU units.

7.5.6 FLARE STACK

A new demountable flare stack has been considered for VRMP. For the new flare system the height of flare stack from grade level is 60 m and the stack diameter is 60”.

7.5.7 FLARE LOAD MITIGATION

The design flare load is determined by common cause failures. Those that typically predominate are either global loss of cooling water or global loss of electrical power. Such failures cause overpressure in many plant subsystems concurrently with the resulting activation of many pressure relief devices.

As stated above, the flare loads provided in the present study are estimated loads based on in-house data. These shall be verified during detail design once the licensor design data consisting of heat & material balance, equipment sizes etc. for various units are available besides equipment layout.

With distributed power supply, the utility failures shall be restricted to minimum to reduce the flare load. Further, during Basic Engineering Package development for licensed as well as open art units inherent design features shall be considered for inclusion to have mitigation within the process system itself to restrict the flare load.

Flare mitigation measures will be adopted to bring down the relief loads of VRMP, with the instrumented reduction of flare load, studies like HIPPS (High Integrity Pressure Protection System) and SIL (Safety Integrity Level) shall have

to be carried out during implementation in order to ensure safety of the plant under various eventualities.

To reduce the resulting flare load, highly reliable Safety Instrumented Systems (SIS) will be adopted that take action during a global overpressure event to reduce the number of pressure relief devices discharging concurrently. Such SISs typically function by isolating the cause of overpressure.

SISs are generally composed of three major components: process parameter sensors, logic solvers and final control elements. The process sensors measure pressure directly, but can use other parameters that infer potential overpressure such as high temperature, low cooling water flow or low amps/voltage. Such systems are provided at individual relief sources to achieve substantial reduction in the total flare load.

The central design principle of SIS is that the risk resulting from the possibility of exceeding the design flare system capacity shall be managed by SISs that acting together provides an overall safeguarding equivalent to ISA SIL3 as defined by ISA Standard S84.01.

Such SIS requires redundancy in all elements. The component configuration typically consists of three transmitters with 2-out-of-3 voting, logic solving in a Triple Modular Redundant (TMR) programmable electronic system (or equivalent) also with 2 out of 3 voting, and redundant field devices (e.g., two isolation valves).

During the subsequent engineering activity, with more flare data available from process packages, efforts shall be made to reduce the flare load and attempt to avoid any new flare installation. If warranted one of the existing flare will be considered for capacity increase.

Broad specifications for flare system are presented in the table 11.6 shown below:

Table: 7.6.4 Broad specifications for flare system

S. No.	Description	Specification	Remarks
1.	HC Flare system		
	OSBL flare header	Dia.=78"	MOC=KCS
	Flare KOD	Dia.= 5 m, length= 30 m	MOC=KCS + 3mm CA
	Flare stack	Dia.=60", height=60 m	MOC = CS; flare tip MOC = Incoloy 825
2.	Acid Flare system		
	OSBL flare header	Dia.= 32"	MOC=KCS + Stress relieved
	Flare KOD	Dia.= 2 m, length= 5.8 m	MOC=KCS + 3mm CA
	Flare stack	Dia.=32", height=60 m	MOC =SS304; flare tip MOC = Inconel 625

Flare header, KOD, Stack sizes considered are preliminary estimations based on in house data and are required to be confirmed during detail engineering.

8.0 INTRODUCTION

Hindustan Petroleum Corporation Limited (HPCL), Visakh refinery is one of the oldest refineries in India commissioned in 1957 by Caltex Oil Refining India Limited (CORIL). It is the first oil refinery on the east coast and the first major industry in Vishakhapatnam, Andhra Pradesh. The installed capacity of the refinery was 0.65 Million Metric Tons Per Annum (MMTPA) in 1957. CORIL was taken over by Government of India and merged with Hindustan Petroleum Corporation Limited (HPCL) in 1978. The refinery has expanded in phased manner over the years: the first expansion done in 1978 was through debottlenecking of units increasing crude processing capacity from 0.65 MMTPA to 1.5 MMTPA. Another major expansion of the refinery was completed in 1985 under Visakh Refinery Expansion Project-I in which the crude processing capacity increased from 1.5 MMTPA to 4.5 MMTPA. The crude processing capacity of refinery was then increased from 4.5 MMTPA to 7.5 MMTPA in 1999 under Visakh Refinery Expansion Project-II. The capacity of Visakh refinery is enhanced to 8.33 MMTPA under the Clean Fuels Project (VRCFP).

The Visakh Refinery is one of the most integrated refineries with three crude distillation units, MS Block (NHT-ISOM-CCR), Diesel Hydro Desulphurization unit, two Fluid Catalytic Cracking units, Diesel hydro treating unit, Visbreaker Unit, Bitumen Blowing unit and Propylene Recovery unit.

In view of the projected demand growth of petroleum products in the country and also to retain its profitability and competitiveness in the long run, HPCL-VR is looking at options to upgrade/ modernize the refinery along with capacity enhancement.

HPCL Visakh refinery has always taken the lead to undertake environmental improvement and pollution abatement programs with respect to the liquid effluent, air emission and solid waste management. HPCL Visakh refinery has well-established Environmental Management System. Various pollution control measures required to meet the prevailing environmental standards are planned at the different stages of execution of the project, viz., design, construction and operational phases.

8.1 INDIAN ENVIRONMENTAL LEGISLATION

Government of India has made many legislations/rules for the protection and improvement of environment in India. Various environmental legislations/rules applicable to the proposed project facilities are as follows.

Table 8.1: Indian Environmental Legislation

Legal Instrument	Relevant articles/provisions
The Environment (Protection) Act, 1986, amended up to 1991	Section 7: Not to allow emission or discharge of environmental pollutants in excess of prescribed standards Section 8: Handling of Hazardous substances Section 10: Power of entry and inspection Section 11: Power to take samples Section 15 – 19: Penalties and procedures
The Air (Prevention and Control of Pollution) Act 1981, as amended upto 1987.	Section 21: Consent from State Boards Section 37: Penalties and Procedures
The Water (Prevention and Control of Pollution) Act, 1974, as amended upto 1988.	Section 24: Prohibition on disposal Section 25: Restriction on New Outlet and New Discharge Section 26: Provision regarding existing discharge of sewage or trade effluent
Environment (Protection) Rules, 1986 (Amendments in 1999, 2001, 2002, 2002, 2003, 2004, March 2008)	Rule 3: Standards for emissions or discharge of environmental pollutants Rule 5: Prohibition and restriction on the location of industries and the carrying on process and operations in different areas Rule 13: Prohibition and restriction on the handling of hazardous substances in different areas Rule 14: Submission of environmental statement
Hazardous Wastes (Management and Handling) Rules, 2008, amended up to 2009	Rule 4: Responsibility of the occupier and operator of a facility for handling of wastes Rule 8: Disposal sites Rule 20: Responsibility of waste generator

Legal Instrument	Relevant articles/provisions
Manufacture storage and import of hazardous chemicals rules 1989 amended 2000	Rule 4: Responsibility of operator
EIA Notification 2006 and subsequent amendments	Requirements and procedure for seeking environmental clearance of projects
Noise Pollution (Regulation and Control) Rules, 2000, amended up to 2010.	Ambient noise standards and requirements of DG sets
MoEF notification dated March 18, 2008 vide circular no G.S.R 186(E) for Oil Refinery Industry	Revised standards for emissions or discharge of environmental pollutants
MoEF notification dated November 9, 2012 vide circular no G.S.R 820(E) for Petrochemical (Basic and Intermediaries) Industry	Revised standards for emissions or discharge of environmental pollutants

The refinery project shall be designed taking into account the above-referred legislations/rules and as per the directives of Environmental Clearance documents. Besides this the proposed effluent and emission standards for Petroleum Refineries will also be compiled for this Project.

A brief description of the environmental protection measures proposed to be adopted in the project both in the operation and construction phase with respect to the various components of the environment like air, water, noise, land, etc., are given in the subsequent sections.

8.2 POLLUTION CONTROL MEASURES

Industrial development is an important constituent in our pursuits for economic growth, employment generation and betterment in the quality of life. On the other hand, industrial activities, without proper precautionary measures for environmental protection are known to cause pollution and associated problems. Hence, it is necessary to comply with the regulatory

norms for prevention and control of pollution. With this in view, various industry specific action plans are formulated known as **Corporate Responsibility for Environmental Protection (CREP)** for progressive improvement in environment management system. The action points for oil refinery are given below:

Air pollution management

- All the refineries located in the critically pollution areas, identified by CPCB, will submit an action plan (within six months) for phase wise reduction of SO₂ emission from the present level.
- Future refineries will have Sulphur Recovery Unit (SRU) with minimum 99% efficiency.
- To enhance the efficiency of SRUs in the existing refineries, an expert committee will be constituted to look into various aspects and suggest a road map within six months.
- With regard to NO_x emission, the new refineries/process units will install low NO_x burners. For retrofitting of low NO_x burners in existing units, the expert committees will suggest the strategies and action plan within six months including NO_x standard.
- The flare losses will be minimized and monitored regularly.
- Refineries will install continuous emission monitoring systems for SO_x and NO_x in major stacks with proper calibration facilities. Action plan for this will be submitted within six months.
- Refineries will also monitor total HO and Benzene in the premises (particularly at loading–loading operations and ETP). The status and action plan will be submitted within six months.
- The expert committee will also suggest an action plan, within six months, for contract and monitoring of hydrocarbon loss & VOC emissions. leak detection and repair (LDAR) programme and vapor recovery systems (for loading & unloading operations within refineries only).

Waste Water management

- Refineries will prepare action plan for conservation of water resources and maximized reuse recycling treated effluent within six months. The treated

effluent discharge quantity (excluding once through cooling water) will be limited to 0.4 m³/per ton (for 90% of time) except for the monsoon season.

- Oil spill response facilities at coastal refineries will be in position within two years. To facilitate this MoEF will coordinate with Coast Guards. Port Trust and departments.

Solid Waste Management

- Refineries will explore new technologies for reduction in the generations of oils sludge Strategy and action plan for liquidation of existing sludge will be submitted within six months
- The petroleum coke having high sulphur content will be sold to /reused by organized industries (having consent from SPCBs), which have systems to control SO₂ emissions. This will be ensured by June 2003.

The design stage Endeavour's to mitigate the problems related to health, safety and environment at the process technology/source level itself. The design basis for all process units lays special emphasis on measures to minimize the effluent generation at source. The specific control measures related to gaseous emissions, liquid effluent treatment/discharges, noise generation, solid waste disposal, etc., along with relevant stipulated standards are described below for operational phase.

8.2.1 Air Environment

The gaseous emissions from the refinery will be controlled to meet all the relevant standards stipulated by the regulatory authorities. Standards applicable to this refinery project can be classified into three categories:

- Emission Standards
- Ambient Air Standards
- VOC Control ,emission and Monitoring

Under the VRMP, the following cases have been shortlisted and finalized. They are

Case A: Existing 2 GTGs in operation (with naphtha as fuel to GTGs) + Balance power import

Case B: Total Captive power plant with naphtha as fuel to GTGs

Case C: Total Captive power plant with natural gas as an option along with naphtha as fuel to GTGs and with natural gas as an option along with naphtha as feed/fuel to Hydrogen Generation Units

The estimated SO₂ emissions releases due to combustion of different types of fuels are given below:

Table 8.2: SO_x Balance for Case A

SO_x from Fuel gas	
UNIT	SO_x (TPD)
FUEL GAS (100ppm)	0.17
TOTAL(A)	0.17
SO_x from Naphtha	
UNIT	SO_x (TPD)
CPP (29 ppm)	0.02
HGU (50 ppm)	0.17
TOTAL (B)	0.19
SO_x from FUEL OIL	
UNIT	SO_x (TPD)
FUEL OIL (4050 ppm)	7.9
TOTAL (C)	7.9
SO_x from FCC coke	
UNIT	SO_x (TPD)
FCC-I (With FGD)	0.23
FCC-II (With FGD)	1.21
TOTAL (D)	1.44
SO_x from SRU	
UNIT	SO_x (TPD)
DHDT SRU	0.6
EXISTING SRU	0.4
NEW SRU	0.8
TOTAL (E)	1.8
TOTAL (A+B+C+D+E)	11.5

Table 8.3: SOx Balance for Case B

SOx from Fuel gas	
UNIT	SOx (TPD)
FUEL GAS (100 ppm)	0.17
TOTAL(A)	0.17
SOx from Naphtha	
UNIT	SOx (TPD)
CPP (27 ppm)	0.06
HGU (50 ppm)	0.17
TOTAL (B)	0.23
SOx from FUEL OIL	
UNIT	SOx (TPD)
FUEL OIL (4700 ppm)	7.81
TOTAL (C)	7.81
SOx from FCC coke	
UNIT	SOx (TPD)
FCC-I (With FGD)	0.23
FCC-II (With FGD)	1.26
TOTAL (D)	1.49
SOx from SRU	
UNIT	SOx (TPD)
DHDT SRU	0.6
EXISTING SRU	0.4
NEW SRU	0.8
TOTAL (E)	1.8
TOTAL (A+B+C+D+E))	11.5

Table 8.4: SOx Balance for Case C

SOx from Fuel gas	
UNIT	SOx (TPD)
FUEL GAS (100 ppm)	0.17
TOTAL(A)	0.17
SOx from Natural gas	
CPP (10 ppm)	0.01
HGU (10 ppm)	0.02
TOTAL(B)	0.03
SOx from Naphtha	
UNIT	SOx (TPD)
CPP (29 ppm)	0.01
HGU (50 ppm)	0.04
TOTAL (C)	0.05
SOx from FUEL OIL	
UNIT	SOx (TPD)
FUEL OIL (4710 ppm)	7.86
TOTAL (D)	7.86
SOx from FCC coke	
UNIT	SOx (TPD)
FCC-I (With FGD)	0.23
FCC-II (With FGD)	1.36
TOTAL (E)	1.59
SOx from SRU	
UNIT	SOx (TPD)
DHDT SRU	0.6
EXISTING SRU	0.4
NEW SRU	0.8
TOTAL (F)	1.8
TOTAL (A+B+C+D+E+F)	11.5

Stack wise emission from VRMP units are as follows:

Table 8.5: Stack Wise Emission

Unit	CDU-IV	VDU-IV	HCU Stack 1	HCU Stack 2	SHC Stack 1	SHC Stack 2	SDA	New HGU Train I	New HGU Train II	New SRU I	New SRU II	New GT-1	New GT-2	New Boiler
No. of stacks	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Min Stack Height based on SO ₂ (M)	43	33	35	35	34	34	34	23	23	33	33	18	18	38
Stack Height (M)	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Dia of stack Tip(m)	3.5	2.3	2.6	2.6	2.5	2.5	2.5	3.8	3.8	1.2	1.2	3.5	3.5	2.9
Temp of gases at tip °C	150	150	150	150	150	150	165	150	150	300	300	120	120	150
Exit velocity of gases (m/s)	6.5	6.5	6.5	6.5	6.5	6.5	6.5	14	14	18	18	14.5	14.5	6.5
Emission Rate Kg/hr SO ₂	41.5	18.1	14.8	28.8	12.1	28.2	19.4	2.6	2.6	17	17	2.3	2.3	27.4
Emission Rate Kg/hr NO _x	50.3	21.9	18.2	35.3	14.8	34.5	23.8	29.3	29.3	24.4	24.4	20.8	20.8	

The NO_x emissions shall be designed to meet the standards as given in following Table.

8.2.1.1 Emission Standards

Table 8.6: Standards for Emissions from Furnaces and Boilers*

Sl. No.	Parameter		Limiting concentration in mg/Nm ³ , unless stated	
			Existing refineries	New refineries/ furnaces/ boilers
1	Sulphur Dioxide (SO ₂)	Gas firing	50	50
		Liquid firing	1700	850
2	Oxides of Nitrogen (NO _x)	Gas firing	350	250
		Liquid firing	450	350
3	Particulate Matter (PM)	Gas firing	10	5
		Liquid firing	100	50
4	Carbon Monoxide (CO)	Gas firing	150	100
		Liquid firing	200	150
5	Nickel + Vanadium (Ni+V)	Liquid firing	5	5
6	Hydrogen Sulphide (H ₂ S) in fuel gas	Liquid / gas firing	150	150
7	Sulphur content in liquid fuel, weight %	Liquid / gas firing	1.0	0.5

*As per MoEF notification dated March 18, 2008 vide circular no G.S.R 186(E) for Oil Refinery Industry

Notes:

- (1) In case of mixed fuel (gas and liquid) use, the limit shall be computed based on heat supplied by gas and liquid fuels.
- (2) All the furnaces/ boilers with heat input of 10 million KCal/hr or more shall have continuous systems for monitoring of SO₂ and NO_x. Manual monitoring for all the emission parameters in such furnaces/ boilers shall be carried out once in two months.
- (3) All the emission parameters in furnaces/ boilers having heat input less than 10 million KCal/hr will be monitored once in a quarter.
- (4) In case of continuous monitoring, one hourly average concentration values shall be met 98% of the time in a month. Any concentration value obtained through

manual monitoring, if exceeds the limiting concentration value, shall be considered as noncompliance.

- (5) Data on Ni + V content in the liquid fuel (in ppm) shall be reported. Ni + V content in the liquid fuel shall be monitored once in six months, if liquid fuel source & quality aren't changed. In case of changes, measurement is necessary after a change.

In addition to the above, the particulate matter in emissions from stacks should not exceed the maximum permissible limit of 5 mg/Nm³.

The refinery complex is designed to meet all the statutory requirements. Some of the major features of these environmental measures are as follows:

- Low sulphur fuels will be used for internal fuel purpose.
- Sulphur Recovery Unit with 99.9% efficiency will be provided.
- Heaters/furnaces will be provided with well proven Low NOx burners to reduce the emissions of Nitrogen Oxides (NOx).
- Under normal circumstances, there will be no continuous/intermittent point releases of volatile hydrocarbon streams. However, if during startup/shut down or an emergency situation any hydrocarbon streams are released, they will be directed to an elevated flare for complete combustion. This will eliminate the possibility of forming an explosive mixture due to sudden release of unburned hydrocarbons to the atmosphere.
- The flares elevation will be such that there will be no impact of thermal radiation on the operating personnel in the refinery. To ensure complete combustion of released hydrocarbons through flares, a pilot burner shall always be burning with the aid of fuel gas. Further, to ensure smokeless and non-luminous flaring, the steam provision at the flare tip is also envisaged.
- The heights of various stacks will be determined taking into consideration the "Guidelines for Minimum Stack Height" as per notification by MoEF dated 19th May 1993, which fixes the minimum stack height based on emission of Sulphur Dioxide.

This is as given below:

$$H=14(Q)^{0.3}$$

Where

H = Stack Height in m,

Q = Sulphur Dioxide emission in kg/hr.

If, the Pollution Control Board specifies any minimum stack height, the higher of the two will be selected. The refinery complex is designed in such a way that the total emissions from the refinery complex will meet all the applicable standards/stipulations.

The total Sulphur Dioxide emissions from the refinery complex after development of proposed additional units and capacity expansion will not exceed the present limit of 11.5 T/day.

8.2.1.2 Ambient Air Standards

The ambient air quality around the premises will be limited to those limits as per National Ambient Air Quality Standards, which are given below:

Table 8.7: National Ambient Air Quality Standards(Gazette No. 217 dated 18 November 2009)

Sl. No.	Pollutant	Time Weighted Average	Concentration in Ambient Air		
			Industrial, Residential, Rural & other areas	Ecologically Sensitive Area	Methods of measurement
1.0	Sulphur Dioxide (SO ₂)	Annual Average*	50 µg/m ³	20 µg/m ³	-Improved West and Gaeke
		24 hours**	80 µg/m ³	80 µg/m ³	-Ultraviolet Fluorescence
2.0	Oxides of Nitrogen as NO ₂	Annual Average*	40 µg/m ³	30 µg/m ³	-Modified Jacob & Hochheiser (Na-Arsenite)
		24 hours**	80 µg/m ³	80 µg/m ³	Chemiluminescence
3.0	Particulate Matter , Size<10 µ	Annual Average*	60 µg/m ³	60 µg/m ³	-Gravimetric -TOEM
		24 hours**	100 µg/m ³	100 µg/m ³	-Beta attenuation

Sl. No.	Pollutant	Time Weighted Average	Concentration in Ambient Air		
			Industrial, Residential, Rural & other areas	Ecologically Sensitive Area	Methods of measurement
4.0	Particulate Matter , Size<2.5 µ	Annual Average*	40 µg/m ³	40 µg/m ³	-Gravimetric -TOEM
		24 hours**	60 µg/m ³	60 µg/m ³	-Beta attenuation
5.0	Ozone O ₃	8 hours**	100 µg/m ³	100 µg/m ³	-UV Photometric Chemiluminescence
		1 hour	180 µg/m ³	180 µg/m ³	Chemical method
6.0	Lead(Pb)	Annual Average*	0.5 µg/m ³	0.5 µg/m ³	AAS/ICP method after sampling on EPM 2000 or equivalent filter paper
		24 hours**	1.0 µg/m ³	1.00 µg/m ³	-ED-XRF using Teflon filter
7.0	Carbon Monoxide (CO)	8 hours**	2 mg/m ³	2 mg/m ³	Non Dispersive Infra red(NDIR)
		1 hour	4 mg/m ³	4.0 mg/m ³	Spectroscopy
8.0	Ammonia (NH ₃)	Annual Average*	100 µg/m ³	100 µg/m ³	Chemiluminescence
		24 hours**	400 µg/m ³	400 µg/m ³	Indophenol blue method
9.0	Benzene	Annual Average*	05 µg/m ³	05 µg/m ³	Gas chromotography based continues analyzer
					Adsorption and Desorption followed by GC analysis
10.0	Benzo(a)P yrene (BaP)	Annual Average*	01 ng/m ³	01 ng/m ³	Solvent extraction followed by HPLC/GC analysis

Sl. No.	Pollutant	Time Weighted Average	Concentration in Ambient Air		
			Industrial, Residential, Rural & other areas	Ecologically Sensitive Area	Methods of measurement
11.0	Arsenic (As)	Annual Average*	06 ng/m ³	06 ng/m ³	AAS/ICP method after sampling on EPM 2000 or equivalent filter paper
12.0	Nickel (Ni)	Annual Average*	20 ng/m ³	20 ng/m ³	AAS/ICP method after sampling on EPM 2000 or equivalent filter paper

* Annual Arithmetic mean of minimum 104 measurements in a year taken twice a week 24 hrs. At uniform interval.

** 4 hourly/8 hourly values should be met 98% of the time in a year. However, 2% of the time, it may exceed but not on two consecutive days.

Whenever and wherever monitoring results on two consecutive days of monitoring exceed the limits specified above for the respective category, it shall be considered adequate reason to initiate regular or continuous monitoring and further investigation.

8.2.1.3 VOC Control, Emission and Monitoring

Fugitive emissions are primarily due to intermittent/continuous leakage or evaporation of Volatile Organic carbons (VOCs) from processing/storage area of the refinery.

The major sources of such fugitive emissions of VOCs in the refinery are the main processing area, the storage tank farm area for crude oil & products and the loading/unloading gantry area. These fugitive emissions originate from the static and dynamic compressor joints and seals used in flanges, pumps, valve

packings and connection joints to the atmosphere like sampling, relief valves, etc. In order to minimize the fugitive emissions, the following measures will be taken during engineering:

- Minimum number of flanges, valves, etc.
- High grade gasket material for packing
- Usage of state-of-the-art low leakage valves preferably with bellow seals
- Usage of pumps with Double Mechanical seals for light hydrocarbon services
- Provisions of floating roof storage tanks
- Provisions of double seal in some of storage tanks
- Provision of covering the oil-water separation units in ETP
- Provision of seals in the drains and manholes

Storage of General Petroleum Products:

Requirements on type of storage tanks shall be as follows:

Table 8.8: Types of Storage Tanks

Sl. No.	Total Vapour Pressure (TVP), KPa	Tank Capacity, m3	Type of Storage Tank
1	> 10	4 – 75	Fixed Roof Tank (FRT) with pressure valve vent
2	10 – 76	75 – 500	Internal Floating Roof Tank (IFRT) or External Floating Roof Tank (EFRT) or Fixed Roof Tank with vapour control or vapour balancing system
3	10 – 76	> 500	Internal Floating Roof Tank or External Floating Roof Tank or Fixed Roof Tank with vapour control system
4	> 76	> 75	Fixed Roof Tank with vapour control system

Notes:

1. Requirement for seals in Floating Roof Tanks:
 - I. IFRT & EFRT are to be provided with double seals with minimum vapor recovery of 96%.
 - II. Primary seal shall be liquid or shoe mounted for EFRT and vapour mounted for IFRT. Maximum seal gap width will be 4 cm and maximum gap area will be 200 cm²/m of tank diameter.
 - III. Secondary seal will be rim mounted. Maximum seal gap width will be 1.3 cm and maximum gap area will be 20 cm²/m of tank diameter.
 - IV. Material of seal and construction should ensure high performance and durability.
2. Fixed Roof Tanks will have vapor control efficiency of 95% and vaporbalancing efficiency of 90%.
3. Inspection and maintenance of storage tanks should be carried out under strictcontrol. For the inspection, API RP 575 may be adopted. In-service inspection with regard seal gap should be carried out once in every six months and repair to be implemented in short time. In future, possibility of on-stream repair of both seals will be examined.

VOC EMISSION STANDARD:

(I) Standards for emissions from storage of volatile liquids are as follows

Table 8.9:Standards for emissions from storage of volatile liquids

Sl. No.	Item	Standards
1	Applicable products	Gasoline, Naphtha, Benzene, Toluene, Xylene
2	Type of loading: (i) Road tank truck (ii) Rail tank wagon	(i) Bottom loading (ii) Top submerged
3	Leak testing for Vapour collection	Annual leak testing
Emission control for Road tank truck/ Rail tank wagon loading		
4	Gasoline and Naphtha: (i) VOC reduction, % or (ii) Emission,	(i) 99.5 or (ii) 5

Sl. No.	Item	Standards
	gm/m ³	
6	Benzene: (i) VOC reduction, % or (ii) Emission, mg/m ³	(i) 99.99 or (ii) 20
7	Toluene/Xylene: (i) VOC reduction, % or (ii) Emission, mg/m ³	(i) 99.98 or (ii) 150

(II) Standards for VOC emissions from wastewater collection and treatment:

- All contaminated and odorous wastewater streams should be handled in closed systems from the source to the primary treatment stages (oil-water separator and equalization tanks).
- The collection system should be covered with water seals (traps) on sewers and drains and gas tight covers on junction boxes.
- Oil-water separators and equalization tanks should be provided with floating/ fixed covers. The off-gas generated should be treated to remove at least 90% of VOC and eliminate odor. The system design should ensure safety (prevention of formation of explosive mixture, possible detonation and reduce the impact) by dilution with air/ inert gas, installing LEL detector including control devices, seal drums, detonation arrestors, etc. The system should be designed and operated for safe maintenance of the collection and primary treatment systems.
- Wastewater from aromatics plants (benzene and xylene plants) should be treated to remove benzene/ aromatics to a level of 10/20 ppm before discharge to effluent treatment system without dilution.

VOC Monitoring:

The standards call for stringent monitoring programme in form of LDAR which is described below:

- Approach: The approach for controlling fugitive emissions from equipment leaks is to have proper selection, installation and maintenance of non-leaking or leak tight equipment. Following initial testing after

commissioning, the monitoring for leak detection is to be carried out as a permanent on-going Leak Detection and Repair (LDAR) programme. Finally detected leaks are to be repaired within an allowable time frame.

- b) Components to be covered: The components that shall be covered under LDAR programme include (i) Block valves; (ii) Control valves; (iii) Pump seals; (iv) Compressor seals; (v) Pressure relief valves; (vi) Flanges – Heat Exchangers; (vii) Flanges – Piping; (viii) Connectors – Piping; (ix) Open ended lines; and (x) Sampling connections. Equipment and line sizes more than 1.875 cm or ¾ in. are to be covered.
- c) Applicability: The LDAR programme would be applicable to components (given at 2 above) for following products/ compounds: (i) hydrocarbon gases; (ii) Light liquid with vapour pressure @ 20⁰C > 1.0 kPa; and (iii) Heavy liquid with vapour pressure @ 20⁰C between 0.3 to 1.0 KPa.
- d) While LDAR will not be applicable for heavy liquids with vapour pressure < 0.3 kPa, it will be desirable to check for liquid dripping as indication of leak.
- e) Leak definition: A leak is defined as the detection of VOC concentration more than the values (in ppm) specified below at the emission source using a hydrocarbon analyzer according to measurement protocol (US EPA – 453/R-95-017, 1995 Protocol for equipment leak emission estimates may be referred):

Table 8.10: Estimates of equipment leak emissions

Sl. No	Component	General Hydrocarbon (ppm)		Benzene (ppm)	
		Till 31 st Dec.2008	w.e.f January 01,2009	Till 31 st Dec.2008	w.e.f January 01,2009
1	Pump/ Compressor	10000	5000	3000	2000
2	Valves/ Flanges	10000	3000	2000	1000
3	Other components	10000	3000	2000	1000

- f) In addition any component observed to be leaking by sight, sound or smell, regardless of concentration (liquid dripping, visible vapor leak) or presence of bubbles using soap solution should be considered as leak.
- g) Monitoring requirements and repair schedule: Following frequency of monitoring of leaks and schedule for repair of leaks shall be followed:

Table 8.11: Monitoring Schedule of VOC emission

Sl. No.	Component	Frequency of monitoring	Repair schedule
1	Valves/ Flanges	Quarterly (semiannual after two consecutive periods with < 2% leaks and annual after 5 periods with < 2% leaks)	Repair will be started within 5 working days and shall be completed within 15 working days after detection of leak for general hydrocarbons. In case of benzene, the leak shall be attended immediately for repair.
2	Pump seals	Quarterly	
3	Compressor seals	Quarterly	
4	Pressure relief devices	Quarterly	
5	Pressure relief devices (after venting)	Within 24 hours	
6	Heat Exchangers	Quarterly	
7	Process drains	Annually	
8	Components that are difficult to monitor	Annually	
9	Pump seals with visible liquid dripping	Immediately	Immediately
10	Any component with visible leaks	Immediately	Immediately
11	Any component after repair/ replacement	Within five days	-

- h) The percentage leaking components should not be more than 2% for any group of components monitored excluding pumps/ compressors. In case of pumps/ compressors, it should be less than 10% of the total number of pumps/ compressors or three pumps and compressors, whichever is greater.
- i) Emission inventory: The refinery shall prepare an inventory of equipment components in the plant. After the instrumental measurement of leaks, emission from the components will be calculated using stratified emission factors (USEPA) or any other superior factors. The total fugitive emission will be established.
- j) Monitoring: Following types of monitoring methods may be judiciously employed for detection of leaks: (i) Instrumental method of measurement of leaks; (ii) Audio, visual and olfactory (AVO) leak detection; and (iii) Soap bubble method.
- k) Data on time of measurement & concentration value for leak detection; time of repair of leak; and time of measurement & concentration value after repair of leak should be documented for all the components.
- l) The pressure relief and blow down systems should discharge to a vapor collection and recovery system or to flare.
- m) Open-ended lines should be closed by a blind flange or plugged.
- n) Totally closed-loop should be used in all routine samples.
- o) Low emission packing should be used for valves.
- p) High integrity sealing materials should be used for flanges.

8.2.1.4 Odour Control

Odor from the refinery complex originates due to fugitive emissions of hydrocarbons, the burning of Sulphur containing fuels, the presence of Sulphides and VOCs in the effluent, the addition of mercaptans to LPG to detect its leakage, etc. Therefore, the design measures suggested as part of controlling stack and fugitive emissions are applicable for odour control as well.

8.2.2 Noise Environment

Ambient Standard for Noise, specified by CPCB is given below:

Table 8.12:Noise (Ambient Standards)

S. No.	Area Code	Category of Area	Limit in dB (a) Leg	
			Day Time	Night Time
1.0	A	Industrial area	75	70
2.0	B	Commercial area	65	55
3.0	C	Residential area	55	45
4.0	D	Silence zone	50	40

Notes:

- (1) Daytime is reckoned in between 6 a.m and 9 p.m.
- (2) Nighttime is reckoned in between 9 p.m and 6 a.m.
- (3) Silence zone is defined as areas upto 100 meters around such premises as hospitals, educational institutions and courts. The silence zones are to be declared by the competent authority.
- (4) Mixed categories of areas should be as "one of the four abovementioned categories" by the competent authority and the corresponding standard shall apply.

Comprehensive measures for noise control will be followed at the design stage in terms of

- Noise level specification of various rotating equipment as per Occupational Safety and Health Association (OSHA) standards.
- Equipment layout considering segregation of high noise generating sources.
- Erecting suitable enclosures, if required, to minimize the impact of high noise generating sources.
- Sizing the flare lines with low Mach number to have lower noise levels.
- Green belt of appropriate width all around the refinery towards noise attenuation

8.2.3 Water Environment:

The maximum water requirement for various purposes in Case A & Case B is estimated and is given below:

- Case A: Existing 2 GTGs in operation (with naphtha as fuel to GTGs) + Balance power import
- Case B: Total Captive power plant with naphtha as fuel to GTGs

Since utility consumptions for case 632 (Case B) and 645 (Case C) are same, both are shown in single column Case B. Utility consumption for Case 623 (Case A) is shown separately.

Table 8.13: Raw Water balance

VRMP		
Unit	Estimated Demand, M3/Hr	
	Case B	Case A
BCW Make-up	123	123
Service Water	215	215
Drinking Water	10	10
Flare System Make-up	5	5
Total Demand	353	353
Effluent Recycle from ETP	165 (Dry) 312(Wet)	165 (Dry) 312(Wet)
Net Normal Demand	188 (Dry) 41 (Wet)	188 (Dry) 41 (Wet)
With 10% margin	207 (Dry) 45 (Wet)	207 (Dry) 45 (Wet)
Back Up for DM Plant Feed (*)	360	430
Net Max Demand	713	783
With 10% margin	784	862
(*) When recycle of treated raw water from ETP to RO plant is not available		

- Cooling water Treatment: Two number Cooling water system shall be used for meeting the demand of additional cooling water. Both Cooling Towers shall be based on sea water. Chemical treatment for pH correction, scale dispersion and copper inhibition etc. and biocides / chlorine for microbial treatment are envisaged.
- Effluent Recycle Plant/DM Plant: An RO based DM plant based upon feed from treated ETP water and various blow down streams is envisaged for meeting the additional DM water requirement. The DM water production shall be in the order of 500 m³/hr.

Liquid Effluent Management System

Effluent Treatment Plants were constructed as measures to control Pollution with respect to the liquid effluent. Refinery consumes large amount of water during processing of the crude. Seawater is mostly used in cooling system.

Fresh water is used for steam generation, bearing cooling water systems, flushing of unit's pipeline, preparation of chemical solution, floor washing, canteen and sanitary requirements, etc. HPCL-Visakh Refinery implemented the task of segregation of process effluents from non-process effluents & cooling waters and installed the following treatment facilities to meet MINAS requirements:

- ✓ ETP-I: Effluent Treatment Plant-I (90 m³/hr Dry Weather/ 135 m³/hr Wet weather)
- ✓ ETP-II: Effluent Treatment Plant-II (275 m³/hr Dry Weather/ 325 m³/hr Wet Weather)
- ✓ ETP-III: ATP – ETP (30 m³/hr)
- ✓ ETP-IV: Effluent Treatment Plant-IV (180 m³/hr). ETP-IV is also provided with contaminated rain water treatment facility of 90 m³/hr.
- ✓ CRW-ETP: Contaminated Rain Water-Effluent Treatment Plant (CRW-ETP) (100 m³/hr)

To take advantages of the latest development in the field of effluent treatment & recycle and to have better control in terms of liquid effluent treatment/management of the entire refinery effluent at single location, it is proposed to install a new state of the art Integrated Effluent Treatment & Recycle Plant (IETP), which shall replace all the existing effluent treatment plants apart from treating additional effluent flow from VRMP facilities. The treated ETP effluent along with various blow down streams (CPP blow down, bearing cooling water CT blow down, process blow downs, etc.) shall be further treated within the integrated plant in a RO based recycle system to produce fresh water and subsequently DM water.

Effluent routing philosophy to the new IETP has been elaborated in the **APPENDIX-I**

The effluent management system in the integrated plant will broadly consist of the following:-

- A. Process Oily (OWS) Effluent Treatment System
- B. Contaminated Rain Water (CRW) Treatment System
- C. Spent Caustic Treatment System

- D. Package Sanitary Sewage Treatment Plant (STP)
- E. Blow downs treatment system/ Effluent Recycle Pretreatment System
- F. RO based Tertiary Treatment/ Recycle Plant
- G. DM Water Generation System (2nd pass RO + MB)
- H. Sludge Handling & Dewatering System
- I. Chemicals Handling & Dewatering System

Total process oily (OWS) effluent generation from the refinery post VRMP is given below in Table-8.14.

Total contaminated rain water (CRW) effluent generation from the refinery post VRMP is given below in Table-8.15.

Total spent caustic effluent generation from the refinery post VRMP is given below in Table-8.16.

Total blow downs are envisaged to be 100 m³/h which includes 75 m³/h CTBD from bearing CT and 11 m³/h from CPP Boiler Blow-down apart from other boiler blow-downs. These blow-downs are envisaged to be routed to recycle section of IETP for fresh water recovery.

TABLE-8.14: Total OWS effluent generation from the refinery post VRMP

S. No	ETP/ Unit	Stream	Flow (m ³ /hr)			
			Actual		Design	
			Dry Weather	Wet Weather	Dry Weather	Wet Weather
1	ETP-I	Combined	30-60	135*	90	135
2	ETP-II	Stream A	100	100	100	100
		Stream B	100	223*	173	223
		ATP-ETP	30*	30*	30	30
3	ETP-III (ATP-ETP)	Routed to ETP-II				
4	ETP-IV (Note-1)	VRCFP block	150*	150*	150	150
		Upcoming DHT	30	30	30	30
5	VRMP (Note-2)	Combined	330	330	330	330
TOTAL OWS Effluent (Existing refinery)			472	670	575	670
TOTAL OWS Effluent (Post VRMP)			802	1000	905	1000

* Because of non-availability of data, actual flow rates has been considered same as design flow rates

Notes:

1. VRCFP block influent is routed to ETP-II receiving sump & then it is pumped to ETP-IV for further treatment.
2. Major process oily effluent streams envisaged from VRMP include ~117 m³/h from CDU/VDU-IV; ~200 m³/h from SWS-I & II (TPH); ~5 m³/h from Flare; ~5 m³/h from floor-washes; and ~5 m³/h average from intermittent streams.

TABLE-8.15: Total CRW effluent generation from the refinery post VRMP

S.No	CRW Stream	Flow (m ³ /hr)
1.	CRW from DHDS (CRW-ETP)	100
2.	CRW (ETP-IV)	90
3.	CRW (VRMP)	200
New CRW Effluent		390

TABLE-8.16: Total Spent Caustic effluent generation from the refinery post VRMP

S. No	Spent Caustic Streams	Design Flow (m ³ /hr)
1.	Spent Caustic from CDUs	1.8
2.	Spent Caustic Streams from MS block units & New DHT	3
3.	Spent Caustic (VRMP)	2.1
Total Spent Caustic Effluent		6.9

- ❖ The capacity of the different section of the integrated plant shall be as follows:

OWS STREAMS

Total Design Capacity = **800 m³/hr Dry Weather (Minimum)**
1000 m³/hr Wet Weather (Maximum)

(Refer Table-8.18 for details)

CTBD STREAMS

Total Design capacity = **100m³/hr**

Recycle section of the integrated plant to be designed for 1100 m³/hr design capacity to accommodate additional 100 m³/hr from blow downs (including 75 m³/h CTBD from bearing CT and 11 m³/h from CPP Boiler Blow-down apart from other boiler blow-downs).

CRW STREAMS

Total Design Capacity = **390 m³/hr** (Refer Table-8.19 for details)

SPENT CAUSTIC

Total Design Capacity = 7 m³/hr (Refer Table-8.20 for details)

Package Sanitary Sewage Treatment Plant (STP)

Total Design Capacity = 30 m³/hr

Augmented ETP-II with maximum hydraulic capacity will still not be able to treat the additional load from VRMP. There will be requirement for one more new ETP for VRMP apart from major modifications in existing ETP-II and ETP-IV (CRW Chain). Apart from this, there are various other advantages to the proposed new integrated effluent treatment & recycle plant, some of which are highlighted below:

- ✓ **Better management:** Treatment of refinery's liquid effluents at single location in new IETP. Oily effluent streams to ETP-I, ETP-II, ATP-ETP, ETP-IV and additional effluent from VRMP shall be treated together at single location i.e., in new IETP. Also, CRW effluent from existing DHDS, MS block and VRMP shall be treated at single location i.e., in CRW treatment chain in new IETP. Replacement of the existing ETPs and additional new ETP for VRMP by a new single integrated ETP would result in better operation, maintenance & management in view of single-point treatment of process effluent from the entire refinery.
- ✓ **Optimum utilization of Man-power & other Resources (including inventory)** in view of single-point treatment of entire refinery effluent.
- ✓ **Compact Plant:** Better space utilization taking advantages of efficient & compact treatment technologies.
- ✓ **Optimum Space Utilization:** Redundant ETP areas can be utilized by HPCL for other purposes.
- ✓ **Better Control & Efficiency:** Deficiencies in existing operation & control facilities in existing ETPs would be taken care in the new IETP. New IETP would also overcome the other deficiencies of the existing treatment system including accommodation of fluctuations in feed effluent quality to IETP. Also, the new IETP would make use of advantages of technological advancements in the field of effluent treatment.

- ✓ **Better treated effluent quality than MINAS:** The new IETP would be designed to meet treated water specifications which are acceptable as feed to the RO recycle plant (including biological nutrients removal in IETP). Moreover, there would be opportunity to have common associated facilities for ETP & recycle plant.
- ✓ **Recovery of Fresh Water:** Part of the fresh water recovered (1st stage RO permeate) from the recycle plant would be reused/recycled for D.M. plant feed whereas balance fresh water will be used for fresh cooling water make-up, thus reducing the dependency of HPCL-Vizag Refinery on fresh water supply by the municipalities. Also, this would reduce cost liability on HPCL-Vizag Refinery for fresh water charges to be paid to the municipalities.
- ✓ **Reduced Cost Liability:** The proposed new integrated ETP & Recycle plant would be aimed to recover the maximum water at ~75% recovery to the tune of ~ 800 m³/h (design wet weather conditions) and the quality of water will be better than the fresh water supply from municipalities in terms of silica. This will reduce the load on fresh water requirement to the tune of ~800 m³/h (maximum during wet weather conditions). HPCL would save upto Rs 26.3 crores in a year @ 822 m³/h for 8000 hours/year operation @ current fresh water rate of Rs. 40/m³.
- ✓ **Better DM Plant Feed Quality:** RO treated water (2nd pass RO permeate) having very low TDS ~5 mg/L) can be directly fed to the Mixed Bed exchangers as feed. This would lower down the consumption of chemicals in DM water production.
- ✓ **No major shut-down:** New IETP can be installed without envisaging any major shut-down. Shut-down will be required primarily for hook-ups. So, existing ETPs can operate simultaneously during project implementation.
- ✓ **VOC System:** VOC handling facilities for ETPs can be common while meeting the latest Environment (Protection) rules of Ministry of Environment & Forests.

Liquid Effluent Summary

The liquid effluents are summarized below:

Table 8.17: Liquid effluent summary

Unit	Continuous/ Intermittent	Effluent Stream	Estimated Quality
CDU-IV /VDU-IV	Continuous	Brine from desalter	PH : 7.5-8.0 BOD @ 20°C: 300 mg/lit COD : 500 mg/lit Suspended Solids : 150 mg/lit Total dissolved solids : 2500 mg/lit Total oil content : 200 mg/lit Free/ Fixed Ammonia : 50 mg/lit Cyanides : 3 mg/lit Phenolic compounds : 3 mg/lit H2S : 50 mg/lit Sulfides as S : 5 mg/lit Sodium 1875 mg/lit Calcium 250 mg/l Magnesium 375 mg/l
	Intermittent(Once in a day for ½ hr)	Spent Caustic	PH:11-12 BOD @, 20°C:35000 mg/lit COD: 40000 mg/lit Suspended Solids: 200 mg/lit Total Dissolved solid:200000 mg/lit Sulphur: 8000 mg/lit Phenolic Compounds:800mg/lit
	Intermittent 2-3 days Once in	Decoking effluent	Suspended solids: 50 mg/l Total oil content 100 mg/l

Unit	Continuous/ Intermittent	Effluent Stream	Estimated Quality
	2-3 years		
	Continuous	Steam generator blowdown	pH 9.0-10.0 TDS 1000-6000 mg/l Total oil content 1.0 mg/l Phosphates 50 mg/l Si-Sio2 50 mg/l Alkalinity 300-400 mg/l KmnO4 value <500 mg/l
	Intermittent Duration : 5 Min Once per shift	Steam generator blowdown	Same as above
FCHCU	Continuous	Boiler Blow down	pH: 9-10 TDS: 1000-6000 mg/l Total Oil Content: 1 mg/l Phosphates: 50 mg/l Si-SiO2: 50 mg/l Alkalinity: 300-400 mg/l KMnO4 Value: <500 mg/l
	Intermittent Duration : 5 Min Once per shift	Boiler Blow down	Same as above
SHCU	Intermittent Duration: 5434.8 kg once in three years (Annual turnaround)	Neutralisation Sol	Hydrocarbon: < 0.1 wt% Water : 98 wt% Soda Ash: 2 wt%
	Continuous	Steam Generator blowdown	pH: 9-10 TDS: 1000-6000 mg/l Total Oil Content: 1 mg/l Phosphates: 50 mg/l Si-SiO2: 50 mg/l Alkalinity: 300-400 mg/l KMnO4 Value: <500 mg/l

Unit	Continuous/ Intermittent	Effluent Stream	Estimated Quality
	Intermittent Duration : 5 Min Once per shift	Steam Generator blowdown	Same as above
SDA			There is no continuous effluent from the SDA section.
SR LPG Treater	Intermittent (in 5- 6 Days)	From Prewash column : effluent generated per 5-6 days in Pre wash column	COMPONENT : KG /Hr NaOH : 81.9 Na ₂ S ₂ O ₃ : 0 Na ₂ S : 250 WATER : 3834 Na ₂ CO ₃ : 0 NaSR : 131.7 TOTAL FLOW : 4298
	Purge caustic effluent generated per hour in solvent separator (purge stream)	Continuous	COMPONENT : KG/HR NaOH : 0.26 Na ₂ S ₂ O ₃ : 0 Na ₂ S : 0 WATER : 1.9 Na ₂ CO ₃ : 0 NaSR : 0 TOTAL FLOW : 2.2
ARU			There is no continuous effluent from the ARU section. The effluent in the minor quantities can be because of leakage, spillage etc of MDEA
NEW ISOM	Intermittent 1-2 hrs/week	Spent Caustic	NaCl:12000-15000 mg/l NaOH: 200 mg/l

Unit	Continuous/ Intermittent	Effluent Stream	Estimated Quality
			Hydrocabons (Saturated)
SWS I & II		Entire stripped water to ETP	Total Oil Content: 200 ppmw Free/Fixed Ammonia: 50 ppmw Phenolic Compounds: Nil H2S: 50 ppmw Phenolic Compounds: 105 ppmw
	Intermittent Duration : 30 Min	Pump Bearing cooling to ETP(m3/hr)	Sulphate : 300 - 550 Mg/Lit Chloride : 45 - 60Mg/Lit TDS : 750 - 1000Mg/Lit PH : 7.5 -8
SRU	Continuous	Blowdown from surface condensers and waste heat bolilers	pH 9.0-10.0 TDS 1000-6000 mg/l Total oil content 1.0 mg/l Phosphates 50 mg/l Si-Sio2 50 mg/l Alkalinity 300-400 mg/l KmnO4 value <500 mg/l
	Intermittent	Boiler blow down	pH 9.0-10.0 TDS 1000-6000 mg/l Total oil content 1.0 mg/l Phosphates 50 mg/l Si-Sio2 50 mg/l Alkalinity 300-400 mg/l KmnO4 value <500 mg/l
HGU	Continuous	Boiler blow down	Amines - <10 ppm wt Phosphate - <15 ppm wt Formic Acid - <100 ppm wt Methanol - <150 ppm wt CU -Nil Fe-< 5 ppm wt

Unit	Continuous/ Intermittent	Effluent Stream	Estimated Quality
			PH-10-11 Salts from DMW concentrated up to 50 times
	Intermittent Duration : 5 Min	Boiler Blow down	Same as above
PRU	Intermittent: 30 min Once in two days	Oil and Chemical Water Effluent	Caustic/MEA: 1 wt% Hydrocarbons: 0.1 wt%
	Intermittent: 30 min (once in a day)	MEA/CAUSTIC WASTE WATER(m ³ /Hr)	Caustic/MEA: 2.5 wt% Hydrocarbons: 0.1 wt% Mercaptans: 600 ppm
Utilities			
Raw water treatment plant(Note- 2)	Intermittent	Water	PH 7.5-8.0 SS mg/l 1500
Bearing Cooling water	Continuous	Blow Down	PH ; 7.5 – 8.5 Suspended solids, mg/lit : 50 NTU Dissolved solids, mg/lit : 5000
	Intermittant (once per shift 0.5 m ³)	Oil skimming	PH ; 7.5 – 8.5 Suspended solids, mg/lit : 100 Oil & Grease, mg/lit : 1000
Flare		Water seal drum	pH : 7.0 – 8.0 Oil: 50-100mg/l HC: 100 mg/l
Boiler BlowDown	Intermittant (once per shift for 5 min)	Blow Down	Amines - <10 ppm wt Phosphate - <15 ppm wt Formic Acid - <100 ppm

Unit	Continuous/ Intermittent	Effluent Stream	Estimated Quality
			wt Methanol - <150 ppm wt CU -Nil Fe-< 5 ppm wt PH-10-11 Salts from DMW concentrated up to 50 times
	Continuous	Blow Down	Same as above
Sanitary waste	Continuous	Water	BOD- 200 ppm COD- 800 ppm TSS- 200 ppm

Notes:

- (1) During normal operation, sour water shall be generated from hydro processing & non-hydroprocessing units for which SWS of approximate capacities of 185 & 300 m³/hr is provided. A part of stripped sour water will be reused while a portion will be sent to ETP for treatment before further reuse through DM plant.
- (2) Spent caustic generated from various process units shall be collected through the separate pipelines and treated within integrated effluent treatment Plant.
- (3) Sufficient storage shall be provided for sour water at the SWS area, so that during startup and shutdown sour effluent can be diverted to these storage tanks instead of diverting to integrated effluent treatment plant.
- (4) Most of the stripped water from non-hydro processed Sour Water Stripper will be reused as Desalter water make-up water and the stripped water from hydro processed Sour Water Stripper will be reused in hydro processing units. This in-plant control measure will reduce the net wastewater load to the ETP considerably.

- (5) Closed blow down system will be incorporated for hydrocarbon liquid discharges in all the process units, which will reduce the wastewater load to ETP both in terms of quantum load and quality. This is another of the in-plant control measures.
- (6) Appropriate segregation and collection philosophy (separate sewers for process waste, contaminated rainwater, spent caustic, cooling tower blow down, boiler blow down, catalyst regeneration waste, etc. will be incorporated for various effluents depending on individual stream characteristics.
- (7) Process area will be paved to avoid contamination of soil/sub-soil/ground water in case of accidental spill/leakage of hydrocarbon liquids.

Reject Characteristics from IETP

Reject from proposed IETP shall be disposed to sea and shall meet the quantitative and qualitative limits of parameters stipulated in proposed Minimal National Standards (MINAS-Refineries) as given below:

Table 8.18: Reject Characteristics from IETP

S. No.	Parameter	Limiting value for concentration (mg/l, except for pH)	Limiting value for quantum (kg/1000 ton of crude processed, except for pH)	Averaging Period
Parameters to be monitored daily: grab samples for each shift with 8-hours' interval				
1	PH	6.0 – 8.5	-	Grab
2	Oil & Grease	5	2	-do-
<u>Parameters to be monitored daily: composite sample (with 8-hours' interval) for 24-hours flow weighted average</u>				
3	BOD ₃ days, 27 ⁰ C	15	6	24-hours
4	COD	125	50	-do-
5	SS	20	8	-do-
6	Phenols	0.35	0.14	-do-

S. No.	Parameter	Limiting value for concentration (mg/l, except for pH)	Limiting value for quantum (kg/1000 ton of crude processed, except for pH)	Averaging Period
7	Sulphides	0.5	0.2	-do-
8	CN	0.2	0.08	-do-
Parameters to monitored once in a month: composite sample (with 8-hours' interval) for 24-hours flow weighted average				
9	Ammonia as N	15	6	-do-
10	TKN	40	16	-do-
11	P	3	1.2	-do-
12	Cr (VI)	0.1	0.04	-do-
13	Total Cr	2.0	0.8	-do-
14	Pb	0.1	0.04	-do-
15	Hg	0.01	0.004	-do-
16	Zn	5.0	2	-do-
17	Ni	1.0	0.4	-do-
18	Cu	1.0	0.4	-do-
19	V	0.2	0.8	-do-
Parameters to monitored once in a month: grab samples for each shift with 8-hours' interval				
20	Benzene	0.1	0.04	Grab
21	Benzo(a) Pyrene	0.2	0.08	-do-

IETP: Treatment Schemes

As evident from the effluent characteristics that effluent streams requires different specific treatment. The principal contaminants present in these effluent streams are mainly oil (free and emulsified), suspended solids, phenols, sulfides, ammonia and organic matter contributing to BOD & COD.

• **Primary Treatment**

This includes Effluent receipt, Free Oil Removal, Physico-chemical Treatment for emulsified oil and sulfides removal.

- Free oil separation in gravity API separator
- TPI separator
- Emulsified oil removal by Dissolved air floatation

• Spent Caustic Treatment System

It is proposed to treat the entire spent caustic streams (from existing facilities and VRMP) together at one place (i.e., in new IETP) by new spent caustic treatment system which converts primarily sulphides present in spent caustic into sulphates, apart from reduction of other contaminants present in spent caustic, e.g., BOD, COD, etc. Spent caustic treatment system shall comprise of storage and oxidation facilities. Spent caustic shall be partially oxidized with the use of plant air in an oxidation column, operating at pressure. CuSO₄ shall be dosed at controlled rate as catalyst. System shall be operated in batch mode with one oxidation column in aeration mode and other in fill / decantation mode. It shall be a pressurized system and the off-gases (at pressure) shall be routed to biological treatment section of new ETP. Treated spent caustic shall be pumped to new ETP for further treatment.

• Secondary Treatment

This includes state of art processes such as Sequencing Biological Reactor (SBR), Membrane Bio Reactor (MBR) or other advanced biological processes to remove BOD along with corresponding COD, residual sulfides and phenols, biological nutrients, ammonia, etc. from the primary treated effluents.

• Slop & Sludge Handling Section

This section comprises receipt of wet slop from various oil handling units, decantation of water portion and finally sending the dry slop to dry Slop tanks in offsite area for further processing with Crude.

Also, handling of various types of sludges generated through the treatment, viz. Oily, Chemical and Bio sludges, including de-watering to be included here.

• Chemicals Handling Section

Handling of various chemicals required to be dosed at various stages of the treatment is included in this section. Chemical storage, solution preparation

and dosing requirements along with safety provisions required form part of the same.

- **Recycle Section**

The recycle plant shall consist of three stages of treatment. These are broadly classified as:

- Pre-treatment Stage
- Reverse Osmosis Stage
- Mixed Bed Stage

- a. Pre-treatment**

Pre-treatment block is the first stage treatment and consist of removal of impurities like residual oil, BOD, COD and inorganic impurities, which may be harmful to the RO membranes. The pre-treatment options shall be finalized based on the technology selected for Effluent Treatment Plant.

- b. Reverse Osmosis**

The Reverse Osmosis unit essentially works on molecular level. It separates the molecular impurities from the water thus making one stream rich in salt molecules and other stream lean in salts thus reducing the TDS of the water. RO shall remove TDS & Silica.

- c. Mixed Bed**

Portion of RO treated water will be polished further in 2nd pass RO and Mixed bed unit to produce DM water quality.

- **Blow Down Streams Treatment**

The blow downs treatment section shall consist of pre-treatment section comprising of clarifier, Dual media Filter (DMF), Activated carbon Filter (ACF) and Ultra filtration section to remove residual inorganic impurities and silt which is harmful for the RO membranes.

- **Contaminated Rain Water Treatment**

The CRWS treatment section shall consist of TPI to remove free oil present in the effluent and a filtration section comprising of DMF & ACF for final polishing of effluent.

A water balance diagram is attached with this chapter as **APPENDIX-II** to present the overall scenario for IETP.

Steps Involving Integrated Process Waste Water Treatment Plant and Tertiary Treatment Plant

Table 8.19: Treatment Schemes

Treatment Section	Treatment Units
ETP - Primary Treatment Section	<ul style="list-style-type: none"> ➤ API oil separators ➤ CPI / TPI oil separators ➤ Dissolved Air Floatation
ETP - Spent Caustic Treatment Section	<ul style="list-style-type: none"> ➤ Oxidation Column.
ETP – Secondary (Biological) Treatment Section	<ul style="list-style-type: none"> ➤ Sequencing Batch Reactor / Mixed Bed Reactor
ETP - Polishing Treatment	<ul style="list-style-type: none"> ➤ Pre treatment for RO ➤ MF/UF membrane
Tertiary Treatment Section	<ul style="list-style-type: none"> ➤ Reverse Osmosis ➤ Mixed Bed

8.2.4 Land

During the design stage itself due care will be taken to select the process technologies generating minimum solid wastes so that their handling, treatment and disposal do not cause any serious impact on the existing land environment. Also, efforts will be made to recycle some of the spent catalysts by way of returning to the original supplier for reprocessing.

The solid wastes management plan proposed is briefly described below. The provisions of Hazardous Waste (Management & Handling) Rules, 2008, amended up to 2009, will be complied with.

There are primarily four types of solid wastes generated in a refinery:

1. ETP Sludge's
2. General Solid Wastes
3. Tank Bottoms

4. Chemicals

ETP Sludge

The oily & chemical sludge (1.5TPD-post VRMP) separated in different units of ETP, viz., API/TPI/DAF shall be dewatered, handled and disposed as per existing practice. The bio sludge (2TPD-post VRMP) from bio-treatment section will be separately dewatered and utilized inside the refinery as manure.

General Solid Wastes

Small quantities of non-hazardous, non-recyclable solid waste consisting of waste refractory, spent insulation, decoking solid waste from CDU/VDU, used filter cartridges, spent charcoal, spent clay and sand will be generated. These wastes (approx 1500T/ year) will be sent to nearby authorized landfill agency for further disposal.

Tank Bottom Sludge

This sludge is generated periodically during the tank cleaning operations approx 1000 T/ tank at the periodicity of 5 years. Tank bottom sludge shall be handled and disposed as per existing practice.

Chemicals

The chemicals used in various process units will be procured, stored and used as per the rules of "Manufacture Storage and import of hazardous chemicals Rules 1989, amended 2000". An estimate of chemicals to be used in process units is given below:

Table 8.20: Chemical Consumption

Chemical	Daily Use
Caustic	5-10 m ³
Lean Amine	400 – 500 m ³
Soda Ash	10-20 kg
Salt	10 kg
Anti foam	1-2 m ³
Solvents	1-2 m ³
Corrosion inhibitor	1-2 m ³

8.3 CONSTRUCTION PHASE

The overall impact of the pollution on the environment during construction phase is localised in nature, reversible and is for a short period.

Air

The suspended particulate pollution generated during transportation will be mitigated by covering the vehicles so as to ensure no spillage. Hosing down the wheels of the vehicles with water and providing washing troughs for them would further mitigate the amount of dust generated. In addition, emission of other pollutants from construction machinery using diesel driven prime movers, will be controlled by proper maintenance.

Noise

Noise emissions from construction equipment will be kept to a minimum by regular maintenance. Heavy and noisy construction work will be avoided during night time.

Water

The existing drinking and sanitation facilities at the refinery will be extended to the construction workforce. This is necessary to reduce pollution of any receiving water body and also to prevent hazards due to water borne vectors. Potable water shall be provided to the workers.

Socio Economic

Being the proposed project an expansion project coming up within existing refinery battery limit, there will be no permanent impact on the existing socio-economic system around the refinery.

8.4 ENERGY CONSERVATION

Design of all the units and facilities has been conceptualized to achieve a high standard of energy efficiency. The experience of the existing refineries and the latest trends in energy conservation in similar industries worldwide are being incorporated in the project in its design stage itself. This is expected to yield appreciable benefits by reduced energy costs and minimum accountable losses.

Energy conservation measures

Some state of the art energy conservation features being implemented in the

project are given below:

- Use of advanced control techniques like pass balancing in heaters for optimum use of utilities and optimising unit yields.
- Use of pinch technology for maximizing heat recovery from hot products, effluents and circulating refluxes by preheating process streams, thus minimizing heater duties and utilities requirements for cooling.
- Maximizing process heat recovery from the units by fully utilizing the circulating refluxes in towers.
- Superior insulation material of adequate thickness on steam lines to minimize heat loss.
- Use of better quality valves and traps on steam lines to minimize leakages.
- All regular and standby drives for the pumps will be high efficiency motors and the use of turbines is strictly restricted to very critical services.
- Balanced Draft furnaces with air preheaters equipped with glass tubes are envisaged to effectively cool the furnace flue gases to as low a temperature as feasible, thereby maximizing heat recovery from the flue gases.
- Use of combined cycle in power plant towards improved efficiency.

8.5 OPERATION AND MAINTENANCE PHASE

It is envisaged that with strict adherence to the pollution prevention and control measures during the design stage, the environmental impacts could be moderated to the minimum possible level during the operation phase.

Air

(A) In-plant Control Measures

Some of the important operational measures, which can reduce the impact on air environment, are as follows:

- Ensuring the operations of various process units as per specified operating guidelines/operating manuals.
- Strict adherence to maintenance schedule for various machinery/equipment.
- Good house keeping practices

(B) Stack and Ambient Air Monitoring

In order to keep a check on the emissions of SO₂, NO_x, SPM and CO from reactor/regenerator, boiler and furnace stacks shall be monitored as per statutory regulations. Continuous monitors for emissions shall be installed on all major stacks. Ambient Air Monitoring Stations shall

continuously monitor quality of the air outside the vicinity of the refinery premises.

Noise

As the plant is going to be operational on a 24-hour basis, noise considerations are very important. All equipments will be specified to meet 85 dB (A) at 1 m distance. The exposure of employees working in the noisy area shall be monitored regularly to ensure compliance with the OSHA requirements.

A green belt exists around the VRMP units. This green belt will help to reduce the noise and visual impact upon the surrounding population as much as possible.

Water

(A) In-plant Control Measures

Some of the measures, which will be taken up during operational phase of the complex are:

- Reducing the actual process water consumption by way of improvement in operation of processing units.
- Reusing the treated effluent
- Ensuring proper monitoring and maintenance schedule for the effluent treatment & recycle plant.

(B) Water Quality Monitoring

The monitoring of raw influent, the intermediate stages of Effluent Treatment & Recycle Plant, the treated effluent/water, the receiving water body and the ground water quality in the surrounding areas will be carried out regularly. For regular monitoring of the operation of various pollution control facilities, a laboratory with sophisticated instruments and well-trained manpower shall be established. An already existing, refinery Pollution Control Cell with qualified Chemical Engineers/Scientists also form part of the facility, which will ensure that all pollution control measures are effectively operating and to carry out day-to-day checks, trouble shooting and further improvements wherever necessary.

Land

To improve the environmental quality following measures are recommended.

(A) In-plant Control Measures

- The solid waste generated in the form of packaging material etc. shall be sold off for making it suitable for reuse by reprocessing.
- The solids wastes identified to be sent to nearby authorized landfill agency for further disposal.
- In order to improve the aesthetics in the plant surrounding, further plantation shall be carried out the around the plant boundary.

Socio-Economic

Since the project is expansion in nature it will have no major impact on the local socio-economic status of the region particularly on infrastructure such as road, railways communication, education and other common facilities. HPCL shall take part actively in the overall development of the area.

8.6 ENVIRONMENT CELL

A Plant Safety & Environment Department under its technical services department, which consists of well-qualified and experienced technical personnel from the relevant fields, will be in place to look after Environment cell.

8.7 SITE ANALYSIS

The refinery is situated at a distance of about 7 km from the main city, Visakhapatnam extending along the shore of a wide bay, on the Bay of Bengal and surrounded by a picturesque Amphitheatre of hills. The physiography of Vishakhapatnam exhibits distinctly three broad features namely (1) two hill ranges forming northern (Kailasa range) and southern (Yarada range) borders, (2) the Waltair high lands extending along the shore and (3) extensive tidal swamp on the eastern side adjoining Bay of Bengal.

Vishakhapatnam refinery covering an area of 511 Acres is situated at about 1 km (Northward) from the foot of Yarada hills. The Refinery is flanked by Hindustan Shipyard, HPCL Marketing Terminal / IOC terminals on the eastern side and Coromandel fertilizers, Hindustan Zinc, Bharat

heavy Plates and Vessels (BHPV) on the western side. M/s Andhra Petrochemicals (APCL) is situated on north eastern side. Residential colonies are located on the southern side and additional tankage project (ATP) of HPCL on the northern side. The refinery can be accessed by road from the southern side (Old National highway) and north-eastern side. There is no CRZ, forest, national park, wild life sanctuary, eco-sensitive areas notified near the refinery.

The soil classification of Vishakhapatnam falls in northern coastal zone are red soils with clay base, pockets of acidic Soils, laterite soils, Soils with PH 4-5. The texture of soil in the region is sandy clay loam.

The climatic condition near the coast is moist and relaxing but get warmer towards the interior and cools down in the hilly areas on account of elevations and vegetation. April to June are warmer months. The temperature decreases with the onset of south-west monsoon and reaches to a minimum of 17.5 degrees by January after which there is a reversal trend till the temperature reaches mean maximum of 34 degree by the end of May. The rainfall recorded around 1082 mm per annum. The wind direction during winter season showed dominant pattern in N-NE sector with a wind speed class of 1-6 and 7-10 kmph.

The social infrastructure is already available and made provision of basic amenities viz. medical, education, communication and transport. In urban medical facilities is well equipped whereas in rural sector the medical facility is mostly available at primary health center. Adequate educational facilities are available such as primary, middle, secondary and higher secondary schools along with medical and engineering colleges and Andhra University in Visakhapatnam.

8.7.1 Resource Planning

Since the refinery has proposed the expansion of the existing production facilities, existing infrastructure facilities available within refinery will also cater to the demand in proposed expansion scenario. Transportation may increase due to vehicular movements. During Construction of the proposed project, temporary increase in population in the form of skilled and unskilled laborers through outsourcing agencies is anticipated. The

area is already occupied with population and existing neighboring industries, so there are meager chances of migratory population.

In land use planning, the refinery is covered by establishing different units. However for the proposed activities, site will be created by dismantling existing marketing terminal which has already been relocated to create site for proposed activities. The refinery has already 40 acres of green belt developed in the existing premises. The total land area available for the Proposed Visakh Refinery modernisation Project is approximately 120 acres out of which an area of 12 acres shall be earmarked for the Green belt development in Refinery /ATP / Gantry / CDU I arealand wherein part of the proposed project facilities are envisaged to be installed.

Infrastructure is available in existing refinery. Since the proposed Project is coming up mostly in existing Refinery and Terminal Area, Same infrastructure will be utilized for physical and social aspects. The exiting amenities and facilities will be upgraded as per the requirement. However provision will be made for additional infrastructure according to assessment done during detailed engineering of the proposed activities. For transportation of crude oil, existing Offshore Oil Tanker Terminal (OSTT) is already available.in addition, single point mooring (SPM) facilities has already been established to bring crude oil through very large crude carriers (VLCC). Crude Cavern being put up by ISPRL shall be utilized to receive crude from VLCC. For products evacuation existing modes of transport such as road, rail, and sea-route and cross country pipeline shall be used.

Existing facilities will be utilized to a maximum extent. Temporary facilities during construction activities like housing, water, fuel, sanitation etc. will be made available to the contractor labourers. Permanent residential colony for employees is available in the city. Corporate Social Responsibility (CSR) funds will be allocated for the social welfare activities such as water, roads, education, health, telecommunications etc for development of human resources.

8.7.2 Analysis of Proposal:

HPCL has always been keen in adopting /integrating new developments/Policies from time to time on latest technologies as well as

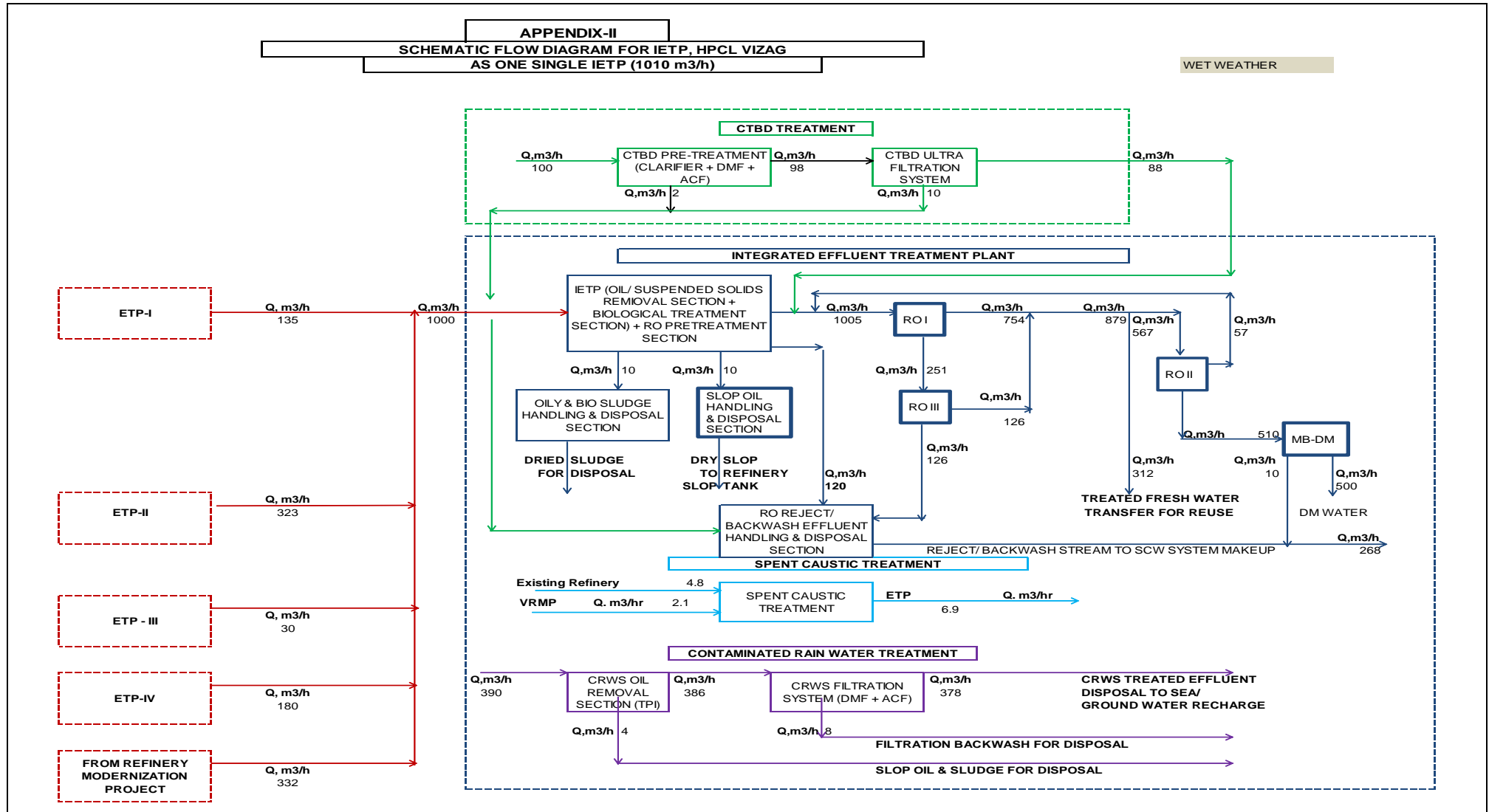
various fuel quality improvement Programs. The Company has already implemented Visakh Refinery Clean Fuels Project (VRCFP) for supply of Euro III/IV quality of Diesel and Petrol in the country. The Refinery already has MoE&F approval for the expansion of the capacity to 10 MMTPA. By proposed expansion, on one hand, BS IV /V grade of diesel and petrol will be supplied to the consumers in the country. Supportive industries which directly or indirectly help to flourish the other industries will also develop in the region. The project will also help in controlling the emission of SO₂ by reducing the sulfur content of the final products and the same shall result in overall improvement of ambient air quality. Also as aspired by local population there will be direct/indirect employment benefit to the population and supporting industries if the proposed activities will be implemented at existing refinery. The refinery is already catering the products to the entire eastern region. The neighboring population will also be benefited by generating infrastructure facilities as aspired by local population. The local population/adopted villages have been benefiting from the continued Corporate Social Responsibility (CSR) activities undertaken by the HPCL Visakh Refinery over the years. Budgetary provisions shall be made under CSR in the field of health, education and self-employment schemes etc for implementation of CSR also in proposed expansion scenario. There will be a positive impact by way of employment, better socio-economic conditions, improved local and regional economy.

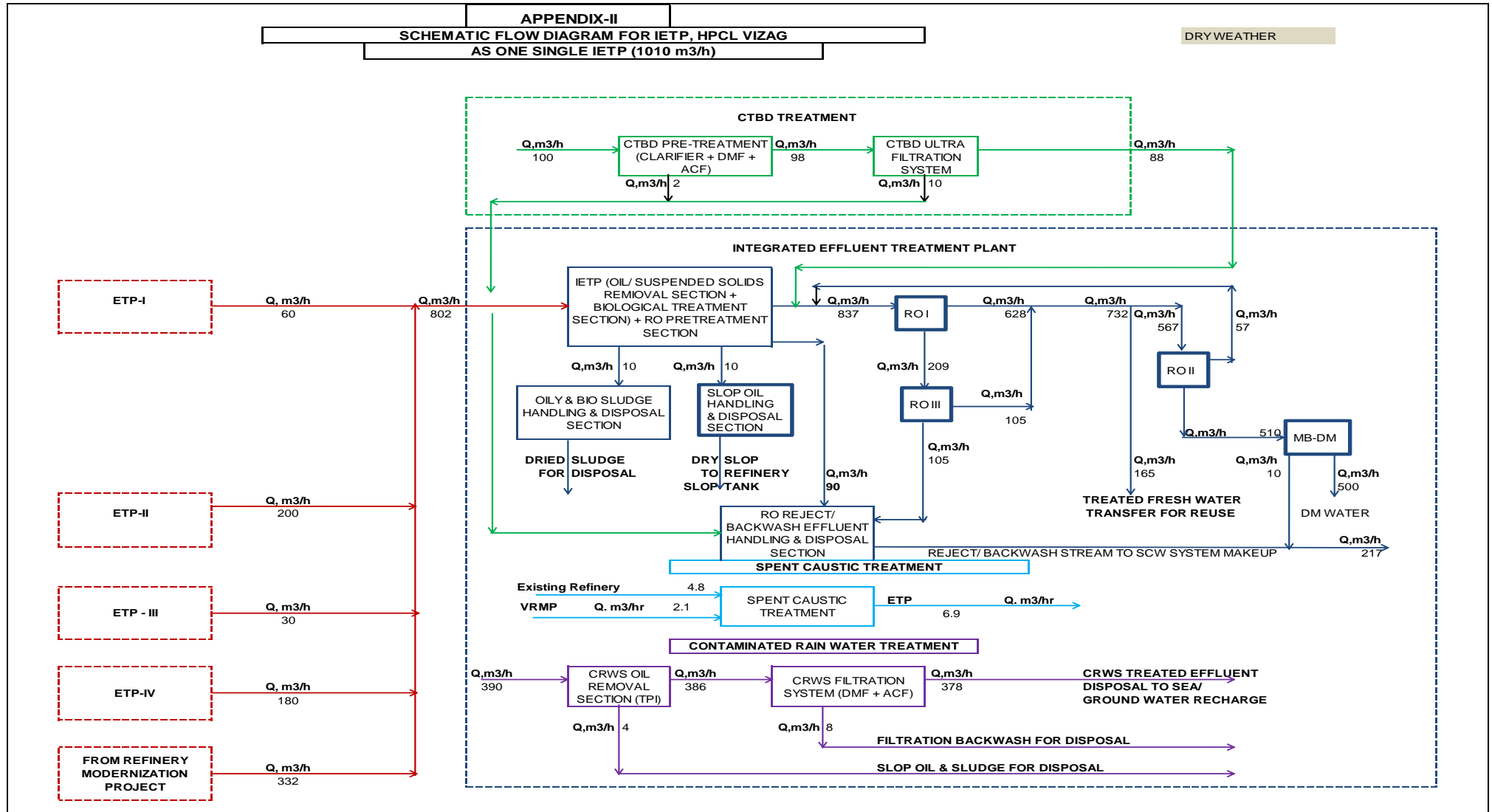
APPENDIX-I
EFFLUENT ROUTING PHILOSOPHY TO NEW IETP

EFFLUENT STREAM	FEED EFFLUENT ROUTING	FEED EFFLUENT TREATMENT
ETP-I OWS	It is proposed to retain the existing OWS receiving sump in ETP-I. The process effluents from CDU-I, CDU-III, FCC-I, QC-Lab & Product tank farm drains will continued to be routed to the existing ETP-I receiving sump as per existing practice. Existing OWS transfer pumps shall be replaced with new OWS transfer pumps of suitable capacity & head to pump OWS effluent from ETP-I OWS sump to new ETP for treatment. Existing OWS sump shall be covered from top with vents connected to VOC treatment system.	ETP-I OWS Effluent shall be treated in new ETP at controlled flow rate. Existing ETP-I treatment units will become redundant. Some of the space presently occupied by ETP-I treatment units will be utilized for installing new separators for CTBD.
ETP-II OWS	It is proposed to retain the existing OWS sump as modifications are proposed in ETP-II area. From existing sump, the OWS effluent shall be pumped to new ETP. Existing OWS sump shall be covered from top with vents connected to VOC treatment system.	ETP-II OWS Effluent shall be treated in new ETP at controlled flow rate. Existing ETP-II treatment units will become redundant.
ETP-III (ATP-ETP) feed	In ATP-ETP, the effluent after oil removal in TPI is pumped directly to ETP-II/ETP-IV for further treatment. A line already exists for transfer of EX-TPI to ETP-II/ETP-IV. It is proposed to retain the OWS sump in ATP-ETP and route the effluent from the sump to new ETP using the existing transfer pumps in ETP-ATP.	ATP-ETP feed effluent shall be treated in new ETP
ETP-IV OWS	The ETP-IV treats OWS effluent from ATP- ETP and upcoming DHT units. Also, as per design, VRCFP OWS effluent should be routed to ETP-IV. But, VRCFP OWS effluent is routed to ETP-II receiving sump and influent is pumped to ETP-IV. It is proposed to pump VRCFP OWS effluent from ETP-II receiving sump to new ETP.	ETP-IV OWS Effluent shall be treated in new ETP at controlled flow rate
VRMP OWS	OWS effluent from VRMP shall be pumped from respective unit of VRMP to new ETP at controlled flow rate for treatment.	VRMP OWS Effluent shall be treated in new ETP at controlled flow rate.

EFFLUENT STREAM	FEED EFFLUENT ROUTING	FEED EFFLUENT TREATMENT
VRMP CRW	CRW effluent from VRMP shall be pumped from VRMP area to new ETP at controlled flow rate for treatment.	VRMP CRW Effluent shall be treated in new CRW treatment chain in new ETP
CRW-ETP	CRW-ETP feed Effluent Routing: It is proposed to treat the entire CRW effluent streams in new ETP. It is proposed to relocate the CRW ETP receiving sump. During dry weather conditions, floor wash effluent shall be routed to floor wash compartment of the receiving sump and then pumped to new ETP by new floor wash transfer pumps by connecting discharge header of these pumps to the proposed OWS discharge header from ETP-I to new ETP. During wet weather conditions, contaminated rain water along with floor wash effluent shall be routed to contaminated rain water compartment of the receiving sump and then pumped to new CRW treatment chain in new ETP.	CRW treatment facilities shall be provided in new ETP.
Spent Caustic	It is proposed to treat the entire spent caustic streams (from existing facilities and VRMP) together at one place (i.e., in new ETP) by new spent caustic treatment system which converts primarily sulphides present in spent caustic into sulphates, apart from reduction of other contaminants present in spent caustic, e.g., BOD, COD, etc. Spent caustic treatment system shall comprise of storage and oxidation facilities. Spent caustic shall be partially oxidized with the use of plant air in an oxidation column, operating at pressure. CuSO_4 shall be dosed at controlled rate as catalyst. System shall be operated in batch mode with one oxidation column in aeration mode and other in fill / decantation mode. It shall be a pressurized system and the off-gases (at pressure) shall be routed to biological treatment section of new ETP. Treated spent caustic shall be pumped to new ETP for further treatment.	
CTBD	In view of limitations in routing CTBD from old & new cooling towers to ETP-II/Skim Pond area, it is proposed that treatment of CTBD from old & new cooling towers shall continued to be carried out together in ETP-I area only. Also, there are execution problems (because of almost no space available in the existing pipe racks) in routing CDU-II once through cooling water directly to ETP-I area. As such, it is proposed that treatment of CDU-II cooling water stream shall continued to be carried out near ETP-II/skim pond area only.	

EFFLUENT STREAM	FEED EFFLUENT ROUTING	FEED EFFLUENT TREATMENT
	<p>Existing intermediate separators are handling CTBD from old cooling tower and once through cooling water from CDU-I. These existing intermediate separators are not adequate to handle combined flow from the proposed cooling water streams. Moreover, they are not properly sized for free oil & suspended solids reduction and removal from the system at present also. Considering the above constraints, it is proposed to have new intermediate separators. The proposed new intermediate separators will be adequately sized as per API design guidelines for efficient removal of free oil (above 150 microns oil globule size) and suspended solids from the cooling water streams. Total 23 numbers of new separators each having design capacity of 600 m³/hr are envisaged for treatment of total design flow of ~13500 m³/h from all the four cooling water streams together.</p> <p>The cooling tower blow down from New Cooling Towers, Old Cooling Towers shall be treated using 12 numbers of new separators to be provided in ETP-I area, which shall be made available by occupying space of existing separators and additional space presently being occupied by some of the existing ETP-I units.</p> <p>The once through cooling water from CDU-II shall be treated using additional 6 numbers of new separators to be provided near ETP-II area.</p>	
<p>Pipe track # 1 & 2 surface drains</p>	<p>At present, pipe track surface drains water is carried through common open trench and routed to old API separators. It is proposed to provide new intermediate separators (similar to separators provided for cooling water blow down streams) near ETP-I area and adjacent to new intermediate separators proposed for CTBD as alternate oil treatment facility for pipe track # 1 & 2 surface drains to take care of any accidental oil in the surface drain water. The new oil separators (2 Nos.) shall be sized similar to new oil separators for CTBD flows.</p>	





7.5.0 UTILITY DESCRIPTION

This chapter provides details of utility requirements and description of new utility system envisaged for refinery post expansion & modernization. The utility requirements have been arrived after considering centralization & integration of existing utility system with new utility system.

The following utility systems are reviewed for DFR:

1. Raw Water System
2. De-mineralized Water System
3. Bearing Cooling Water System
4. Sea Cooling Water System
5. Compressed Air System
6. Nitrogen System
7. Steam, Power & BFW System
8. Condensate System
9. Power Plant Configuration
10. Internal Fuel Oil & Fuel Gas System

Utility consumption for the refinery post-expansion has been estimated considering following basis:

- Operating data of existing Units.
- For those units where there is revamp, the utility consumption for revamped capacity is estimated based on current utility consumption of the unit.
- In-house data for new units.

Utility system for refinery post-expansion is arrived considering the existing utility system and integration/centralization to the extent possible. The details of existing utility systems installed in the refinery are given in Attachment 4E of Section 4 Design Basis.

7.5.1 REFINERY UTILITIES SUMMARY

In DFR, there are three short-listed cases:

- Case A (LP Case 623): 2 GTG (Naphtha based) + Balance Power Import
- Case B (LP Case 632): Total Captive Power (Naphtha based)
- Case C LP Case 645): Total Captive Power (NG based) and NG as feed/fuel to HGU

Since utility consumptions for case B and Case C are same, both are shown in single column named "No Power Import". Utility consumption for Case 623 is shown separately.

The utility summary for VRMP facilities are tabulated below in Table 7.5.1:

Table-7.5.1: VRMP utilities summary

S.N	System	Units	No Power Import	2 GTG+ Power Import
1	Raw Water	m3/hr	207 (Dry) 45 (Wet)	207 (Dry) 45 (Wet)
2	DM Water	m3/hr	275	330
3	Bearing Cooling Water	m3/hr	2800	2800
4	Sea cooling water	m3/hr	48800	30052
5	Instrument Air	Nm3/hr	12042 Nor 13820 Max	12042 Nor 13820 Max
6	Plant Air	Nm3/hr	980 Nor 2662 Max	980 Nor 2662 Max
7	Nitrogen	Nm3/hr	1360	1360
8	Boiler Feed water	TPH	1400	1088
9	Steam	TPH	VHP : 16.5 MP : 124 LP : 102	VHP : 16.5 MP : 124 LP : 73.7
10	Power	MW	Existing: 90 New :135.2	Existing: 90 New :129.5
11	Condensate Pure Suspect	TPH TPH	916 47.2	605.6 47.2
12	Fired duty	MMKcal /hr	737	692

7.5.2 RAW WATER SYSTEM

From the existing raw water reservoir and a new raw water tank (converted from refinery crude tank to raw water tank), raw water will be pumped to the various consumers in the refinery to meet its process and other requirements.

Raw water shall be used as follows for VRMP facilities:

- As make up to the bearing cooling water system
- As feed to the DM water system
- As make up water for new flare system
- As feed to drinking water system and
- As service water for operating hose stations for various miscellaneous uses in the plant.

Existing System Details:

- **Raw Water Reservoir:**

Following are the details of existing raw water reservoir:

- ✓ Total Capacity: 136500 M3
- ✓ Operating Capacity: 72000 M3
- ✓ Height (Min/Max): (15' / 23')
- ✓ No. of days of storage for existing refinery: ~5 days

Post VRMP, proposed sources of raw water are as follow: (a) GVMC and (b) refinery ETP effluent water recycle through RO.

- **Existing Raw Water Pumps:**

Following are the details of existing raw water pumps.

Table 7.5.2: Existing Raw Water Pumps

Project	Name	Number & Capacity
VREP-II	Raw Water Pump	2W+1S – 250 Cum/hr each
	DM Water Feed Pump	2W+1S – 350 Cum/hr each
VRCFP	Raw Water Pump	2W+1S – 300 Cum/hr each
	DM Water Feed Pump	
DHT	Raw Water Pump	1W+1S – 300 Cum/hr each
	DM Water Feed Pump	

• **Existing Raw Water Pipelines & Tanks:**

- 18” and 10” discharge line from Reservoir pumps with interconnection facility to the raw water tanks in DM Plant area.
- There are 3 Raw water tanks (2 nos. of 1400 cum capacity each and 1 no. tank of 1710 Cum capacity)

VRMP Raw water requirement

The estimated raw water requirement for various purposes for VRMP facilities is given below in Table-7.5.3

Table 7.5.3: VRMP Raw Water Requirement

VRMP		
Unit	Estimated Demand, M3/Hr	
	No Power Import Case	2 GTG+ Power Import
BCW Make-up	123	123
Service Water	215	215
Drinking Water	10	10
Flare System Make-up	5	5
Total Demand	353	353
Raw water generated from ETP Treated Effluent (RO Plant)	165 (Dry) 312(Wet)	165 (Dry) 312(Wet)
Net Normal Demand	188 (Dry) 41 (Wet)	188 (Dry) 41 (Wet)
With 10% margin	207 (Dry) 45 (Wet)	207 (Dry) 45 (Wet)
Back Up for RO-DM Plant in ETP (*)	360	430
Net Max Demand	713	783
With 10% margin	784	862
(*) When recycle of treated raw water from ETP to RO plant is not available		

Following are the total refinery requirement post-VRMP:

Project	No Power Import Case	2 GTG+ Power Import
Existing Refinery	600	600
DHT	225	225
VRMP(inclusive of loss & margin)	784	862
Total Maximum Requirement	1609	1687

Days Cover:

The existing Raw water reservoir shall be catering to Existing Refinery Raw water requirement post VRMP also. Hence there will not be any change in No. of days of storage for existing refinery: ~5 day (excluding DHDT)

- After service change existing Crude Tank 120-T-01C should be utilized for storing the raw water required for VRMP.

Following are the details of Tank 120-T-01C:

Tank Capacity : 63671 M3

Operating Capacity : 51427 M3

Height: 13.5 Mtrs, Dia: 79 Mtrs.

- Available volume of Crude Tank 120-T-01C for raw water storage ~ 40750M3 {63671*0.8 (Pumpable volume) * 0.8 (margin for sp.gr increase)}
- No. of days of storage for VRMP: ~ 8 days (#)

#: Based on Normal consumption of 207 M3/Hr.

Since the Raw water required for VRMP will be supplied by Greater Visakh Municipal Corporation / RO Treated Effluent from ETP, there will not be any requirement of treatment facility to treat the raw water.

Raw water pumps specifications

1. Bearing Cooling Water Make up and Service water pumps

Estimated requirements for bearing cooling water make-up, Service water, Flare system make up in the complex is given below:

Requirement (m³/hr) : 343

To meet above requirements following pumps shall be provided:

No. of Pumps : 1 operating + 1 standby
Type : centrifugal
Capacity : 380 m³/hr
Head : 85 m
MOC
Casing : CI
Impeller : Bronze
Drive : Electric
Motor Power : 100 KW

2. DM Plant Feed Pumps

Estimated maximum requirement for DM Plant feed for VRMP will be ~ 430 m³/hr.

To meet above requirements following pumps shall be provided:

No. of Pumps : 1 operating + 1 standby
Type : centrifugal
Capacity : 480 m³/hr each
Head : 85 m
MOC
Casing : CI
Impeller : Bronze
Drive : Electric
Motor Power : 150 KW

The above pumps are considered in DFR for costing purpose. However, since total existing raw water pumping capacity is higher than actual required quantity for existing facilities (including DHT), adequacy of existing raw water pumps (VREP-II,

VRCFP & DHT) shall be checked for relocation of some of these pumps for VRMP requirement during BDEP & detail engineering stage.

7.5.3 DM WATER SYSTEM

DM water in refinery is required for the following major purposes:

- As process water (for solution preparation, etc.) in some process units
- As boiler feed water make-up for the generation of steam
- As dilution water for the preparation of caustic solution
- During start-up of the Sour Water Stripping units
- For jacket cooling of some compressors, if required

DM water in the refinery complex is required as Boiler feed water make-up, process water for dilution.

DM Water requirements for VRMP will be generated in the RO system of tertiary treatment plant in the New Integrated Effluent Treatment Plant. Effluent from the new IETP will be the feed to this RO system for generation of DM water. Provision of fresh raw water as feed to RO is also provided as backup in case of non availability of effluent from the IETP to RO plant.

Post VRMP, existing resin based DM-II facility will be dismantled as it is very old unit, however, DM-III will be retained. Post VRMP, Augmented VRCFP DM Plant (including DHT) and DM-III systems will be integrated with the new DM system (VRMP) for flexibility purpose. The integrated facilities will feed the users of dismantled DM-II facility also.

DM Water Requirement for VRMP:

The demand summary of DM water in various units is given below in Table 7.5.4

Table 7.5.4: DM water Demand

	Unit Name	DM water (M ³ /Hr)	
		No Power Import Case	2 GTG+ Power Import
A.	Main Processing Unit		
	CDU / VDU	2	2
	NHT/CCR/ISOM	1	1
B.	Auxiliary Units		
	HGU Deaerator	154	154

	Unit Name	DM water (M ³ /Hr)	
		No Power Import Case	2 GTG+ Power Import
	CPP Deaerator	90	140
	Net Requirement	247	297
	Total with 10% margin:	~275	~330

Note: BFW requirement of process units (except HGU) will be supplied from CPP Deaerator.

RO Specifications

DM water requirement of VRMP units is 330 m³/hr and existing refinery requirement is 480 m³/hr (300 m³/hr of post VRCFP + 180 m³/hr of DHT). Post VRMP DM water requirement of entire refinery will be 810 m³/hr.

It is proposed to install a new RO DM plant of capacity 500 M³/Hr in IETP to produce the DM water from treated ETP effluent. New RO DM plant along with VRCFP Augmented DM plant including DHT of Capacity 360 M³/Hr will be catering the total refinery DM water requirement of 810 M³/Hr.

Post VRMP the existing DM II plant will be dismantled and DM III will be retained and considered as standby.

The normal feed to new RO DM Plant shall be IETP treated effluent. However, provision of fresh raw water supply from raw water storage tank also has been considered as a back up feed water to RO DM plant at IETP.

Storage

Feed water storage

Fresh raw water backup will be directly supplied to DM Plant. No separate surge tank of feed water to the DM plant is envisaged.

DM water storage

Two fixed roof type DM water tanks of 12 hrs storage shall be provided & 85% of the operating volume. Normally one tank will be receiving DM water from the DM plant and the second tank will be supplying DM water to consumers. DM tanks shall be nitrogen blanketed. Higher tank capacity considered to take care of start-up / intermittent requirements.

DM storage tank

Type : Cone roof with N2 blanketing

VRMP Requirement ~ 330 m³/hr

Capacity equivalent to 12 hrs storage = 3960 m³

Nominal capacity of tank = ~ 4660m³

No. of tanks = 2

DM water Transfer pumps for Process Units

Two (1 operating + 1 standby) DM water transfer pumps have been considered. These will transfer the DM water from the DM water plant to the process users.

No.of pumps :1 w+1s (Process)

Type : Centrifugal

Capacity : 180 m³/hr

Head : 75 m

MOC : Casing & Impeller : SS304L

Motor power : 50 KW

DM water transfer pumps for Steam generation

Two (1 operating + 1 standby) DM water transfer pumps have been considered. These will transfer the DM water from the DM water plant to CPP unit in the integrated complex.

No.of pumps :1w+1s

Type : Centrifugal

Capacity : 150 m³/hr

Head : 75 m

MOC : Casing & Impeller : SS304L

Motor power : 40 KW

The new DM water distribution headers shall be interconnected with existing DM water headers at appropriate location. This shall be considered while preparing BDEP & detail engineering.

Caustic Requirement:

Caustic solution for the refinery complex is required for the following purposes:

- For desalting of crude and off-gas scrubbing in CDU/VDU
- For LPG Caustic treating unit
- For catalyst regeneration in HCU/DHT, Isomerisation units
- In CCR-Regeneration
- For RO plant, CPU and Effluent treatment plant
- ATF treating unit
- TGT Unit

The above requirements, with the exception of the catalyst regeneration requirement, are either intermittent or storage has been provided within the unit, so that caustic transfer from the caustic system to the process units are intermittent.

Common caustic unloading and storage facilities will be provided within the DM plant, from where Caustic shall be supplied to various process units intermittently.

7.5.4 BEARING COOLING WATER (BCW) SYSTEM

The new re-circulating bearing cooling water system shall cater to the following main requirements:

- As cooling medium for pumps/rotary equipment requiring bearing/ seal pot cooling.
- As cooling medium for critical services coolers for which use of sea water as cooling medium is not recommended.

Existing BCW system consists of

- **BCW Cells:**

Following are the details of existing BCW cells:

Project	Number & Capacity (*)
VR	1W + 1S – 75 Cum/hr
VREP - I	1W + 1S – 125 Cum/hr
VREP - II	1W + 1S – 200 Cum/hr
DHDS	1W + 1S – 100 Cum/hr

Project	Number & Capacity (*)
VRCFP + DHT (**)	4W – 800 Cum/hr

(*) Although the cells are having (1W+1S) configuration but in actual operation, all cells are operating.

(**) Under VRCFP, 3 Cells (2 W+ 1S) of 800 cum /hr was considered with provision for adding one more cell of same capacity. Under DHT project, to accommodate the BCW quantity one more cell was added and the stand by cell also was considered as working, hence all 4 cells are in operation.

- **BCW Pumps:**

Following are the details of existing BCW pumps:

Project	Number & Capacity (*)
VR	1W + 1S – 75 Cum/hr
VREP – I	1W + 1S – 125 Cum/hr
VREP – II	1W + 1S – 200 Cum/hr
DHDS	1W + 1S – 100 Cum/hr
VRCFP + DHT	4W + 2S – 800 Cum/hr

- **BCW Supply & Return Headers:**

- ✓ From VRCFP BCW tower 30”/26”/20” header for supply and return is run.
- ✓ From other existing BCW systems respective supply and return headers are run to the units.

The VR, VREP-I, VREP-II and DHDS BCW systems which are relatively old and smaller systems located at different locations within the refinery. With centralization, the old facilities can be dismantled.

Visakh Refinery had made an adequacy study and concluded that the capacities of VR, VREP-I & DHDS BCW can be accommodated in the VRCFP+DHT BCW system and necessary engineering drawings are under preparation. Subsequently, the old BCW towers and the BCW Supply and Return offsite pipelines can be removed.

Under VRMP, it is proposed to consider VREP-II BCW capacity in VRMP BCW system and removal of VREP-II BCW system also.

With above, post VRMP, there will be only two BCW system, 1. VRCFP+DHT 2. VRMP. The cell & pump capacities shall be same and necessary interconnection shall be provided for the same.

The Bearing cooling water requirement of various process units, utilities & offsite are given below in the Table 7.5.5

Table 7.5.5: VRMP bearing cooling water requirement (m³/hr)

	Unit Name	BCW Requirement (m3/hr)
A	Main Processing Unit	
	CDU / VDU	147
	FC_HCU	188
	NEW ISOM	72
	NHT REVAMP	9
	CCR REVAMP	15
	DHDT Revamp	10
	SHCU	150
	SDA	124
	PRU	13
	Alkylation Unit	150
B	Auxiliary Units	
	Hydrogen Generation Unit	145
	SR LPG treating	1
	SW stripper unit -I	73
	SW stripper unit -II	
	Amine Regeneration Unit	
	Sulphur Recovery Unit	
C	Utility Systems	
	Compressed Air System	700

	Unit Name	BCW Requirement (m3/hr)
	Steam/Power Generation System	300
	SRR/ Sub Station / Control Room	100
	Bearing Cooling Water for Utility Systems	50
	IETP	100
D	Offsite	200
	Total :	2547
	Total with 10% margin:	~2800
	No. of BCW Towers @800 m3/hr	4+1

Bearing Cooling Tower

The new bearing cooling water system will meet total demand of all the VRMP facilities viz., CDU/VDU, SDA, New ISOM, PRU, and Slurry HCU, Full conv. HCU, HGU, SWS/ARU/SRU, SR LPG treating units, Revamp Process Units (NHT/CCR/DHT), Utilities and Offsite.

Under VRMP BCW system, following capacities shall be considered:

Project	Capacity
VREP - II	400 Cum/hr
VRMP	2800 Cum/hr
Total	3200 Cum/hr

The bearing cooling water requirement is 2800 m3/hr for VRMP facilities. As part of centralisation of bearing cooling water system, the new bearing cooling system shall cater the bearing cooling requirement of VREP-II of existing refinery also, which will be 400 M3/Hr. Hence total bearing cooling water requirement is 3200 m3/hr.

In view of standardisation of cell capacity with DHT bearing cooling water cell capacity the new bearing cooling water system shall have five cells (4W + 1S) each of capacity 800 m3/hr.

Bearing cooling water pumps and other auxiliary items

To cater BCW requirement for VRMP and VREP-II of existing refinery , 5 pumps (4 W+1S) of 800 m³/hr capacity have been considered .

Type	:	Horizontal centrifugal
Type of Drive	:	5 Electric motor
Electrical Motor Power	:	210 KW
No. of pumps	:	4 operating + 1 stand by
Capacity	:	800 m ³ /hr each
Head	:	60 m

The bearing cooling water shall be chemically treated with a proprietary chemical formulation containing Organophosphonate (HEDP) as PO₄ and polymeric scale dispersant (low mol wt. polymaleic acid or polyacrylic-sulphonic acid co-polymer). In addition to this copper inhibitor benzotriazole and Zinc Sulphate shall be dosed.

Microbial dosing system: Bromine shall be dosed through metering pumps directly from bromine drum rack.

PH of the bearing cooling water shall be maintained by dosing concentrated H₂SO₄ at regulated rate intermittently to maintain pH in the range of 7.5 to 8.0. Acid dosing facility shall comprise of dosing pump, dosing drum, acid unloading /transfer pumps and acid storage tank.

Cycles of concentration

Considering availability of water and efficiency of the inhibitory treatment program, the existing BCW System is designed to operate at 2-3 cycle of concentration. In view of standardization, the new bearing cooling water system will also be designed to operate at cycle of concentration (COC) of 2-3 in all cases.

Make up pump & Side stream filters

The makeup water for the Bearing Cooling Tower will be pumped from the Raw water pump located near Raw water storage tank. Side stream filters with total capacity based on 1.0 - 2% of the cooling tower capacity will be provided so as to maintain the suspended solids contents within the stipulated limits in the bearing cooling water. In all the cases, there will be one number side stream filter of filtration capacity 65 m³/hr.

The existing & new BCW supply & return headers shall be interconnected at appropriate location. This shall be considered during BDEP preparation & detail engineering.

7.5.5 SEA COOLING WATER SYSTEM

Sea Cooling Water (SCW) is mainly used as cooling medium in coolers and condensers in process units, utilities & off sites.

Existing Cooling water system:

The present design sea cooling water systems are as follows:

- VREP II System: 14,000 Cum/hr (4+1 cells & 4+2 pumps each of 3500 m³/hr)
- VRCFP System (*): 14000 Cum/hr (4 +1 cells & 4 +1 pumps each of 3500 m³/hr)
- Once Through System: 3W + 2S pumps. Four of 4800 M³/hr & One of 4000M³/hr. caters to CDU-I, CDU-II, ATF Merox, High Lift Pump House (HLPH) Turbine Coolers and as make-up water to VREP-II & VRCFP SCW system.

(*) DHT: 1 Cell of 3500 m³/hr added to VRCFP Sea Cooling water System along with one pump. The (4+1) configuration is including this additional cell & pump.

The unit wise consumption of the VREP-II re-circulating CW (Sea) is given below in Table 7.5.6:

Table 7.5.6: VREP-II Re-circulation SCW Consumption

UNIT	RECIRCULATING SEA CW REQUIREMENT, M ³ /HR, MAXIMUM
CDU/VDU-III	4025
FCCU/GCU-I	3915
VBU	450
ATU	800
SRU-I/II (2*150)	300
Utilities & Offsites	50

UNIT	RECIRCULATING SEA CW REQUIREMENT, M ³ /HR, MAXIMUM
Sub - Total	9540
DHDS	1708
Total	11248

The unit wise consumption of the VRCFP re-circulating CW (Sea) is given below:

Table 7.5.7: VRCFP Re-circulation SCW Consumption

UNIT	RECIRCULATING SEA CW REQUIREMENT , M ³ /HR,
NHT / CCR / ISOM	2635 900 (NHT)+1013 (CCR) + 385 (FCC NHT)+ 337 (ISOM)
FCC Gasoline Treater	300
PRU	1570
LPG ATU / CFC / ARU	133
Hydro-processing SWS	345
SRU	3
FCC-II	4548
Control room A/C	900
Utilities & Offsite	2850
DHDT	3200
Total	16484

The unit wise consumption of Once through Cooling water system is as follows:

Unit	Requirement (M3/Hr)
CDU-I	1800
CDU-II	4700
ATF Merox	75
HLPH Turbine Coolers	1500
Make-up to VREP-II SCW	3000
Make-up to VRCFP SCW	3300
Total	14375

Cooling water System for New Units

The cooling water system envisaged for the VRMP Project is sea water closed loop recirculation type. Two sea cooling water systems will cater to the requirements of VRMP process units, utilities, offsite & CPP within the complex. The cooling water system includes cooling towers, cooling water transfer pumps, cooling water distribution network. Post VRMP, the existing re-circulating sea cooling water network will be integrated with the new re-circulating cooling water system and advantage of margin available in existing system shall be utilised.

Cooling water requirement

The cooling water requirement of various process units is given below in the Table-7.5.8

Table-7.5.8 Cooling water requirement (m³/hr)

	Unit Name	No Power Import Case	2 GTG+ Power Import
A	Main Processing Unit		
	CDU / VDU	7068	7068
	FC_HCU	4373	4373
	New ISOM	664	664
	NHT Revamp	47	47
	CCR Revamp	195	195

	Unit Name	No Power Import Case	2 GTG+ Power Import
	DHDT Revamp	337	337
	SHCU (including FG ATU)	3200	3200
	SDA	6	6
	PRU	676	676
	Alkylation Unit (Future)	1364	1364
B	Auxiliary Units		
	Hydrogen Generation Unit	1759	1759
	SR LPG treating	6	6
	SW stripper unit -I	4015	4015
	SW stripper unit -II		
	Amine Regeneration Unit		
	Sulphur Recovery Unit		
C	Utility Systems		
	Compressed Air System	2160	2160
	Steam/Power Generation System	17044	0
	IETP	100	100
D	Miscellaneous	1350	1350
	Sub-Total	44364	27320
	Total with 10% margin:	48800	30052

Cooling Tower

The new sea cooling water system will meet total sea cooling water demand of all the VRMP facilities viz., CDU/VDU, SDA, New ISOM, PRU, Slurry HCU, Full conv. HCU, HGU, SWS/ARU/SRU, SR LPG treating units, Revamp Units (NHT/CCR/DHT), Utilities and Offsite.

Cooling water requirement of existing CDU-I has not been considered as CDU-I will be de-commissioned post VRMP.

NHT/CCR/DHDT Revamp Cooling water requirement shall be taken from VRCFP CW system considering that VRCFP & VREP II Sea cooling water systems are integrated.

Cooling Water requirement of CDU-II and ATF Merox has been considered in the new Recirculation CW system.

Cooling Water requirement of HLPH pump turbine to be retained as Once-through CW system due to proximity of the sea water canal.

There is no adequate space near the existing VREP II and VRCFP recirculating sea cooling water systems for locating the new proposed facilities. Further, as the proposed units are at the ends of the refinery, it is prudent to keep the sea cooling water towers split appropriately and located at the respective ends close to the proposed units so that the large size supply and return headers can be avoided within the refinery pipe rack. Hence, the new cooling towers are distributed at two ends of the refinery plot area.

Table 7.5.9: New Cooling Tower I

Cooling Tower I		
Unit Name	No Power Import Case	2 GTG+ Power Import
CPP/CPU	17044	0
ISOM	664	664
IETP	100	100
HGU	1759	1759
CDU 2	4700	4700
ATF MEROX	75	75
Total	24342	7298
With 15% Margin	27993	8393
No. of CW Towers each of 4000 m3/hr	7+1	3+1

Table 7.5.10: New Cooling Tower II

Cooling Tower II		
Unit Name	No Power Import Case	2 GTG+ Power Import
CDU /VDU	7068	7068

Cooling Tower II		
Unit Name	No Power Import Case	2 GTG+ Power Import
SHC	3200	3200
SDA	6	6
SRU Block	4015	4015
Compressed air	2160	2160
SR LPG Treating	6	6
Alkylation Unit (Future)	1364	1364
PRU	676	676
HCU	4373	4373
Misc	1350	1350
TOTAL	24218	24218
With 15% Margin	27850	27850
No. of CW Towers each of 4000 m3/hr	7+1	7+1

Total CW requirement post VRMP = 76532 m3/hr. (11248+16484+48800)

Make-up Cooling water (M3/Hr):

Table 7.5.11: Make up Sea Cooling Water

Cooling Tower	No Power Import Case	2 GTG+ Power Import
VREP II	3000	3000
VRCFP	3300	3300
HLPH Pump	1500	1500
New CT 1	6746	3373
New CT 2	6746	6746
Total	~ 21290	~17920

Recirculating sea cooling water pumps and other auxiliary items

No Power Import Case:

Pumps for Cooling Tower I

To cater to the VRMP cooling tower I, 9 pumps (7 W+2S) of 4000 m³/hr capacity have been provided.

Type	:	Horizontal centrifugal
Type of Drive	:	7 Electric motor +2 Steam Turbine
Electrical Motor Power	:	950 KW
Turbine	:	Extraction Type (35 Kg/cm ² g to 3 Kg/cm ² g)
No. of pumps	:	7 operating + 2 stand by
Capacity	:	4000 m ³ /hr each
Head	:	60 m

Pumps for Cooling Tower II

To cater to the VRMP cooling tower II, 9 pumps (7 W+2S) of 4000 m³/hr capacity have been provided.

Type	:	Horizontal centrifugal
Type of Drive	:	7 Electric motor +2 Steam Turbine
Electrical Motor Power	:	950 KW
Turbine	:	Extraction Type (35 Kg/cm ² g to 3 Kg/cm ² g)
No. of pumps	:	7 operating + 2 stand by
Capacity	:	4000 m ³ /hr each
Head	:	60 m

2 GTG+ Power Import

Pumps for Cooling Tower I

To cater to the VRMP cooling tower I, 4 pumps (3 W+1S) of 4000 m³/hr capacity have been provided.

Type	:	Horizontal centrifugal
Type of Drive	:	3 Electric motor +1 Steam Turbine
Electrical Motor Power	:	950 KW
No. of pumps	:	3 operating + 1 stand by
Capacity	:	4000 m ³ /hr each
Head	:	60 m

Pumps for Cooling Tower II

To cater to the VRMP cooling tower II, 9 pumps (7 W+2S) of 4000 m³/hr capacity have been provided.

Type	:	Horizontal centrifugal
Type of Drive	:	7 Electric motor +2 Steam Turbine
Electrical Motor Power	:	950 KW
Turbine	:	Extraction Type (35 Kg/cm ² g to 3 Kg/cm ² g)
No. of pumps	:	7 operating + 2 stand by
Capacity	:	4000 m ³ /hr each
Head	:	60 m

H2SO4 Dosing Pump

No. of pumps: 1W+1S
Type: Double diaphragm
Capacity: 80 lit/hr
Head: 10 M
MOC: Casing: Alloy 20, Impeller: PTTE (Diaphragm)
Moto Power: 0.1 KW

H2SO4 unloading/transfer pump

No. of Pumps: 1W+1S
Type: Centrifugal

H2SO4 Storage Tank

Dimension: 3M DIA x 4M HT
MOC: CS
CA: 3MM
Design Pressure: Full of Liquid

H2SO4 Dosing Vessel

Type: Horizontal
Dimension: 0.8m Dia & 1 m length
MOC: CS
CA: 3 MM
Design Pressure: 3.5 kg/cm²g

Vendor Package for

1. Chlorinating system, 40kg/hr of four numbers
2. Cooling Water Requirement

Head: 10 M
MOC: Casing & Impeller: ASTM A743 TYPE CN7M
Motor Power: 0.2 KW
Capacity: 5 m³/hr

Cycles of concentration

The New cooling water system will be designed to operate at cycles of concentration (COC) of 1.1.

Side Stream Filters

Side stream filters with total capacity based on 1.0 - 2% of the cooling tower capacity will be provided so as to maintain the suspended solids contents within the stipulated limits in the recirculating cooling water.

Side stream filtration capacity (M3/Hr)

	No Power Import Case	2 GTG+ Power Import
Cooling Tower 1	2 X 320	1 X 320
Cooling Tower 2	2 X 320	2 X 320

Makeup cooling water Pump:

No Power Import Case:

In existing refinery make up sea cooling water is supplied by 5 number HLPH pumps with one of capacity 4000M3/hr and four of 4800M3/hr each.

Total Capacity of HLPH Pump: 18400M3/hr (One pump of capacity 4800M3/Hr considered as spare)

Post VRMP Make Up cooling water required: 21290 M3/hr

New Makeup Cooling water required: One pump of capacity 4000 M3/Hr

Type	:	Horizontal centrifugal
Type of Drive	:	Electric motor
Electrical Motor Power	:	1000KW
No. of pumps	:	1 operating + 1 Standby
Capacity	:	4000 m3/hr
Head	:	40 m

2 GTG+ Power Import:

Post VRMP Make Up cooling water required: 17920 M3/hr and which can be

catered by existing HLPH pumps.

The adequacy of LLPH pumps and sea canal from LLPH to HLPH for increased quantity of sea water shall be checked during BDEP & detail engineering.

7.5.6 COMPRESSED AIR SYSTEM

Compressed air is required for following main requirements:

- As instrument air to operate the various instruments in the facility and also for the purging of some control panels.
- As scouring air (plant air) for regenerating pressure sand side stream filters of cooling water systems, etc.
- As service air for operating hose stations for various miscellaneous uses in the plant, including providing breathing air to personnel during vessel entry, etc.

Compressed air required for all the above uses is generated at a centralized location in the plant and distributed to the various users through headers. Two qualities of compressed air are produced and distributed.

- a) Plant air comprising compressed air cooled to ambient temperature. Quality of plant air and service air are same. This air though not containing any entrained water droplets is saturated with the water vapours at supply condition.
- b) Instrument air comprising compressed air cooled to ambient temperature and drier to remove water vapour to meet stringent atmospheric dew point requirements.

Following are the details of existing compressed air system:

Table 7.5.12: Existing Air Compressors

Project	No. of Air Compressors	Capacity (Nm ³ /hr)
VR/VREP I/VREP II	1 No – Mini Elliott	2940
	1 No - Old Elliott	5400
	1 No - New Elliott	5400
	1 No – VREP II	5400
DHDS	1 No.	5400
VRCFP	1 No.	5400
	1 No. (reciprocating)	250 (for emergency purpose)
DHT	1W + 1S	5400

- Total installed design capacity of Air Compressors is 35340 NM3/hr. Standby compressor capacity & reciprocating compressor capacity not considered.
- Post VRCFP, three Air Compressors (New Elliott, DHDS and VRCFP) are only run.
- The mini Elliott is pressed into operation for special requirements viz., FCC catalyst loading. During normal operation, this is not operated normally.

Air Drier Systems:

The no. of Air Driers are as follows:

- 3 nos of 750 NM3/hr each
- 4 nos of 1750 NM3/hr each
- 2 nos of 2750 Nm3/hr each
- 1 no of 3900 NM3/hr (under DHT)
- 1 no 115 Cum capacity LP Air receiver (under DHT)

Consumption Requirement

The requirements of plant air and instrument air for VRMP facilities are given in Table 7.5.13 and Table 7.5.14 respectively.

Table-7.5.13 Plant Air (Nm³/hr)

Unit Name	Plant Air (Nm ³ /hr)	
	Max continuous Demand	Intermittent
CDU / VDU	Nil	1390
FC HCU	Nil	540
SHCU	Nil	540
NEW ISOM	Nil	51
CCR Revamp	Nil	7
HGU	Nil	811

Unit Name	Plant Air (Nm ³ /hr)	
	Max continuous Demand	Intermittent
SDA	Nil	Nil
PRU	Nil	69
DHDT Revamp	Nil	30
Utility Systems		
Cooling Water System (Both the BCW & SCW)	Nil	1050
Steam/Power Generation System		1000
- Steam Boiler	Nil	
- BFW	Nil	
- Condensate Polishing Unit	Nil	
IETP	130	
Offsite Facilities		340
Miscellaneous	680	
Total :	810	1390 (Max Int)

Table- 7.5.14 Instrument Air (Nm³/hr)

Unit Name	Instrument Air (Nm ³ /hr)	
	Max continuous Demand	Intermittent
CDU / VDU	525	
PRU	225	
FC HCU	600	
New ISOM	350	1572
CCR Revamp	240	

Unit Name	Instrument Air (Nm ³ /hr)	
	Max continuous Demand	Intermittent
NHT Revamp	82	
SHCU	600	
SDA	400	
Alkylation Unit	300	
DHDT Revamp	155	
Auxiliary Units		
Hydrogen Generation Unit	1800	3270
ATF Merox	36	
SR LPG Treater	28	
SW stripper unit -I	3706	
SW stripper unit -II		
Amine Regeneration Unit		
Sulphur Recovery Unit		
Utility Systems		
Cooling Water System	30	
DM Water Plant	100	
Compressed Air / N ₂ System	50	
Steam/Power Generation System	335	500
- Steam Boiler		
- BFW		
- Condensate	50	
Polishing Unit		
Fuel / Flare System	60	

Unit Name	Instrument Air (Nm3/hr)	
	Max continuous Demand	Intermittent
IETP	20	
Offsite Facilities	100	
Miscellaneous	160	
Total :	9952	3270 (Max Int)

Total Air Requirement:

Table 7.5.15: Total Air requirement

Description	Normal (Nm3/Hr)	Maximum (Nm3/Hr)
Instrument Air	9952	11422
Plant Air	810	2200
Total	10762	13622
Total with 10% leakage margin	11838	14984
Total with 10% design margin	13022	16482 (~ 16500)

System Requirement:

Post VRMP, compressed air system of existing refinery shall be integrated with the new system. Post VRMP, the compressed air requirement of entire refinery will be 36065 m³/hr (16500 Nm³/hr of VRMP + 19565 Nm³/hr of existing refinery including DHDT). For existing refinery consumption no margin has been considered.

Considering retention of the Air compressors installed under DHDT (1W+1S), VRCFP (1 No) and DHDS (1 No) which are relatively new compressors, post VRMP total available capacity is (3 W+1 S) @ 5400 NM³/Hr each), i.e. 16200 NM³/Hr.

The Balance compressed air is 19865 NM³/Hr (36065 – 16200). It is proposed that Air compressor for N₂ system shall be combined with Compressed Air System compressor. The air requirement for N₂ System is 6000 Nm³/hr.

For the Balance Compressed Air & N₂ System Air requirement i.e. 25865 NM³/Hr (19865 + 6000), (2W+1S) new compressors of capacity 13,000NM³/Hr each shall be provided.

Post VRMP total instrument air requirement will be 22436 NM³/Hr (VRMP: 11422NM³/Hr + Existing Refinery: 11014 NM³/Hr.)

Considering removal of existing 3 nos. of 750 NM³/Hr each and 4 nos. of 1750 NM³/Hr each Air driers total generation capacity available is 9400 NM³/Hr.

For the Balance instrument air i.e. 13036 NM³/Hr (22436 - 9400) 2 new air drier of capacity 7,000 NM³/Hr each shall be provided.

- a) Centrifugal Compressor (2 w + 1 s)
Suction pressure : Atmospheric
Discharge pressure : 8.13 kg/cm²(g)
Capacity : 13,000 NM³/HR
M.W.: 29
BKW : 1850 KW

- b) LP air receiver (1 no)
Type : Vertical
Height : 6200 mm
Dia: 2500 mm
MOC : CS
C.A. : 3 mm
Design pressure : 10.5 kg/cm²(g)
Design Temp. : 65°c

- c) HP air receiver (1 no)
Height : 13000 mm
Dia: 5000 mm

MOC : CS
C.A. : 3 mm
Design pressure : 34 kg/cm²(g)
Design Temp. : 65°c
Hold-up Time: 30 Min

d) HP air compressor (1 No.)

Suction pressure : 5.0 kg/cm²
Discharge pressure : 31.5 kg/cm²(g)
Capacity : 250 Nm³/hr
BKW : 30 KW
M.W.: 29

d) Dryer (2 nos., Both operating)

Capacity : 7000 NM³/HR each
Type : Split Flow, Heat Reactivated type Closed circuit Dual bed
Adsorption, No purge loss

Interconnection between existing and new instrument & plant air headers shall be provided at appropriate location. This shall be considered in BDEP and detail engineering.

7.5.7 NITROGEN SYSTEM

The inert gas (Nitrogen) is required in the refinery for initial purging, dry out and for catalyst regeneration. The inert gas is also required in Offsite for blanketing and in flare header purging. Nitrogen plant is provided to cater to the inert gas requirement of the VRMP project. Centralization of new facility with existing facility is not envisaged because of plot plan constraints.

Requirements:

The continuous/intermittent supply of Nitrogen will be required for the following purposes:

- Reactor section dry out

- Purging of system during start-ups and shutdowns
- During catalyst regeneration
- Continuous purging of compressor seals
- Blanketing of surge drums and storage tanks
- Flare header purging in offsite

Process related activities such as reactor section dryout, system purging, catalyst regeneration etc. require high purity nitrogen (>99.5% purity). Accordingly a new cryogenic nitrogen plant based on air separation technology shall be provided to cater to the nitrogen requirement of VRMP.

Following is the details of the Nitrogen System of existing refinery

Table 7.5.16: Existing Refinery Nitrogen System

Project	System Details
DHDS	200 Nm ³ /hr – PSA based. Not in use.
DHT (Augmented VRCFP N ₂ Plant)	Gaseous: 3500 Nm ³ /hr Eq. Liquid: 610 Nm ³ /hr Vaporizer: (4W+4S) of 4050 Nm ³ /hr Storage: 5 nos. of 75 m ³

The Table 7.5.17 below gives the Nitrogen requirements of the various units under VRMP.

Table 7.5.17: NITROGEN REQUIREMENT (Nm³/hr)

A.	Unit Name	Nitrogen Requirement (Nm ³ /hr)	
		Max continuous Demand	Intermittent
	CDU / VDU	NIL	688
	FC HCU	125	9784
	New ISOM	NIL	5590
	NHT Revamp	NIL	NIL

	Unit Name	Nitrogen Requirement (Nm ³ /hr)	
	CCR Revamp	15	NIL
	DHDT Revamp	19	1062
	SHCU	115	6696
	PRU	237	NIL
	Alkylolation Unit	55	210
B.	Auxiliary Units		
	Hydrogen Generation Unit	130	20000
	SW stripper unit -I	NIL	595
	SW stripper unit -II	NIL	895
	Amine Regeneration Unit	NIL	1506
	Sulphur Recovery Unit	333	4092
C.	Utility Systems		
	DM/ Condensate Polishing Unit	100	
	Total :	1129	Max Int : 20000
	Total with (10% leakage and 10% design margin):	~1360	Max Int : 24200

Gaseous Nitrogen Generation Capacity

Gaseous nitrogen from the nitrogen plant is meant for meeting the continuous demand for VRMP facilities. Normal N₂ demand is ~1360 NM³/hr (with 10 % margin for leakage & 10% margin for design).

Since post VRMP DHDS N₂ plant will not be operational, the capacity of 200 NM³/Hr of DHDS N₂ plant also has been considered in VRMP N₂ Plant. (The intermittent requirement of ~100 Nm³/hr for offsite purging for existing facilities and requirement of ~ 3000 Nm³/hr of nitrogen for 3 days and 3 times in a year for thawing operation can be catered as maximum intermittent requirement of 20000 Nm³/hr has been considered and total quantity of nitrogen for one thawing operation, i.e. 216000 Nm³ can be fulfilled as per Scenario 2 mentioned below)

To cater these requirements following systems are envisaged.

Gaseous Nitrogen plant of capacity = 1360+200=1560 Nm³/hr

Hence,

Nitrogen Plant=1 No.

Capacity

Gaseous ~1560 Nm³/hr.

Type of plant = Cryogenic

Liquid = To be optimized based on gaseous Nitrogen requirement during detailed Engineering.

Liquid Nitrogen Capacity:

The liquid nitrogen generation capacity of the plant is calculated as follows:

START UP REQUIREMENTS

SCENARIO 1:

S.N	UNIT	SERVICE	TOTAL NITROGEN ,NM3
1.	FC HCU	Start up	140000
2.	SRU	Start up	50000
3.	HGU	Start up	34572
4.	SHCU	Start up	182000
TOTAL			406572
TOTAL (WITH 10% MARGIN)			~447230

SCENARIO 2:

S.N	UNIT	SERVICE	TOTAL NITROGEN ,NM3
1.	FC HCU	1st Start up + shutdown + 2 nd start up	190000
2.	HGU	1st Start up + shutdown + 2 nd start up	69143
3.	SHCU	1st Start up + shutdown + 2 nd start up	247000
TOTAL			506143
TOTAL (WITH 10% MARGIN)			~556760

Considering 10 % as design margin, the liquid N₂ comes out to be 556760 Nm³/hr

NITROGEN STORAGE

Liquid Nitrogen shall be stored in pressurized storage vessels. Storage capacity of vessel as follows.

Based on the above scenarios, the maximum nitrogen requirement is in

Scenario -2

Total Nitrogen requirement = 556760 Nm³

Equivalent Liquid Nitrogen capacity ~ 860 m³

Number of vessels = 5

Capacity of each vessel = 200 m³ (Liquid capacity)

Vaporizer Specification

As unit wise nitrogen rates during emergency shutdown is not completely available, the maximum N₂ rate is 20000 Nm³/hr.

Vaporizer capacity: (20000)*1.21 (design margin) = 24200 Nm³/hr

= 30000 Nm³/hr (#)

Type of vaporizer: Atmospheric Air heated vaporizer

No. of vaporizers: Two (one operating + one standby).

As start-up & shutdown requirements for each unit is not completely available, the liquid storage & vaporizer capacity may be re-validated during BDEP & detail engineering.

Interconnection between new & existing nitrogen headers shall be provided at appropriate location for flexibility purpose. This shall be considered during BDEP & detail engineering.

7.5.8 Boiler Feed Water Requirement

Boiler feed requirement of various units is given in Table-7.5.18. The figures have been arrived at from the steam generation figures (excluding the steam generation from the back pressure drives) and considering 3% blow down losses.

Table 7.5.18 - Boiler feed water (TPH)

	Unit Name	BFW(TPH)	BFW (TPH)
		No Power Import Case	2 GTG+ Power Import
A.	Main Processing Unit		
	CDU / VDU	35	35

	Unit Name	BFW(TPH)	
		No Power Import Case	2 GTG+ Power Import
	FC_HCU	57	57
	SHCU	71	71
B.	Auxiliary Units		
	HGU	521	521
	SRU	105	105
	CPP	483	200
	Total	1272	989
	Total With 10% Margin	1400	1088

To cater the BFW requirement of the VRMP units it is proposed to install two deaerator, one specifically to cater the Hydrogen unit requirement and another located inside the CPP to cater the other process unit and CPP requirement.

7.5.9 STEAM AND POWER SYSTEM

The steam shall be produced in the captive power plant. The fuel to CPP shall be naphtha. There are mainly three levels of steam in the refinery viz: VHP, MP and LP. The steam is being generated / consumed in process units at these levels. The steam consumption in the various units for different purposes such as:

- Process use (Chemical reaction, Stripping steam, Heating etc.)
- Internal fuel oil atomization,
- Steam tracing of lines (congealing service)
- Tankage heating
- Deaerator
- Intermittent requirement like snuffing, decoking, soot blowing, purging, flushing of lines/equipment etc.
- As motive fluid in steam ejectors in ejectors & steam turbines
- Air conditioning units for the Control rooms and the administrative building

Steam Requirement

Tables 7.5.19 below give the consumption / generation figures for steam in various

units at VHP, MP & LP levels of steam respectively. The steam requirement for various units has been estimated based on in-house data as well as licensors's inputs.

Table 7.5.19: Steam requirement (No Power Import Case)

	Unit Name	STEAM (T/Hr)		
		VHP	MP	LP
A.	Main Processing Unit			
	CDU / VDU	-	51.16	-10.29
	FC_HCU	98	-7.3	-75.35
	SHCU	39.2	-1	-93.14
	New ISOM	14	15	0.24
	SDA	-	-	12.18
	PRU	-	-	10.61
	Alkylation Unit	-	19.9	-
	NHT Revamp	7	0.18	
	CCR Revamp	-6	0.55	0.1
	DHDT Revamp	0.9	0.4	0.3
B.	Auxiliary Units			
	HGU	-178.1	-	6.49
	SW Stripper Unit I	-	-	66.57
	SW Stripper Unit II	-	17	61.45
	SRU	-	-	-86.08
	SR LPG Treating Unit	--	-	0.07
	ARU	-	0.3	68.98
C.	Utility Systems	40	17	-23.2
	HGU Deaerator			68
	CPP Deaerator			86
	Total :	15	113	93
	Total with 10% margin:	16.5	124	102

Table 7.5.20: Steam requirement (2 GTGs + Balance Power Import Case)

	Unit Name	STEAM (T/Hr)		
		VHP	MP	LP
A.	Main Processing Unit			
	CDU / VDU	-	51.16	-10.29
	FC_HCU	98	-7.3	-75.35
	SHCU	39.2	-1	-93.14
	New ISOM	14	15	0.24
	SDA	-	-	12.18
	PRU	-	-	10.61
	Alkylation Unit	-	19.9	-
	NHT Revamp	7	0.18	
	CCR Revamp	-6	0.55	0.1
	DHDT Revamp	0.9	0.4	0.3
B.	Auxiliary Units			
	HGU	-178.1	-	6.49
	SW Stripper Unit I	-	-	66.57
	SW Stripper Unit II	-	17	61.45
	SRU	-	-	-86.08
	SR LPG Treating Unit	--	-	0.07
	ARU	-	0.3	68.98
C.	Utility Systems	40	17	-23.2
D.	HGU Deaerator			68
	CPP Deaerator			60
	Total :	15	113	67
	Total with 10% margin:	16.5	124	73.7

Power Requirement

Following Table 7.5.21 gives the power requirement of the various units under normal operating conditions.

Table 7.5.21- Power requirement (kW)

	Unit Name	No Power Import Case	2 GTG+ Power Import
A.	Main Processing Unit		
	CDU / VDU	10916	10916
	FC_HCU	27349	27349
	SHCU	24562	24562
	New ISOM	2202	2202
	SDA	4004	4004
	PRU	126	126
	Alkylation Unit	2500	2500
	NHT Revamp	537	537
	CCR REVAMP	1646	1646
	DHDT Revamp	3067	3067
B.	Auxiliary Units		
	HGU	15227	15227
	SW Stripper Unit I	584	584
	SW Stripper Unit II	1284	1284
	SRU	1960	1960
	SR LPG Treating Unit	76	76
	ARU	1589	1589
C.	Utility Systems		
	Raw Water System	250	250
	Sea Cooling water	13800	8600
	Bearing cooling water	1000	1000
	DM water plant/CPU	816	816
	Compressed Air System	3818	3818
	IETP	1500	1500
	Solid Handling Facility	667	667

	Unit Name	No Power Import Case	2 GTG+ Power Import
	Tracing	467	467
D.	Offsite Facilities	3033	3033
	Total	122980	117780
	Total with 10% margin:	135278	129558

7.5.10 POWER PLANT CONFIGURATION

CPP Configuration for No Power Import Case:

Existing CPP Configuration:-

GTG	ISO Capacity (MW)	Operating Capacity (MW)	HRSG Generation (TPH) @ MP level (10 kg/cm ² g, 250 deg.C)
4 Frame - V	25 Each	4 X 21.3	4 X 60
2 Frame - III	9 Each	2 X 7.18	2 X 27
Total		99.6	294

Frame III GTGs are considered for scrapping. Therefore, will not be considered in overall configuration post VRMP.

Existing Boiler detail:

Boiler data	Design capacity	Operating capacity	Temperature
IBH - 9	84.92 TPH, 36 KG/CM2G.	75 TPH, 36 KG/CM2G.	360 deg.C
IBH - 10	84.92 TPH, 36 KG/CM2G.	75 TPH, 36 KG/CM2G.	360 deg.C
New CO-Boiler	40.0 TPH, 38 KG/CM2G.	40 TPH, 36 KG/CM2G.	360 deg.C
OLD CO-Boiler	20 TPH, 36 KG/CM2G.	18 TPH, 36 KG/CM2G.	360 deg.C
WIL 8	63 TPH, 28 KG/CM2G.	50.0 TPH, 28 KG/CM2G.	285 deg.C
BHPV	50.0 TPH, 30 KG/CM2G.	50.0 TPH, 28 KG/CM2G.	285 deg.C

WIL 8 and BHPV boilers operating at 28 kg/cm² G level are considered for scrapping. Therefore, will not be considered in overall configuration post VRMP.

Steam & Power requirements:

Existing units steam & power requirement:	New units steam & power requirement:
VHP Steam = 7.5 TPH	VHP Steam = 16.5 TPH
MP Steam = 129 TPH	MP Steam = 124 TPH
LP Steam = 77 TPH	LP Steam = 102 TPH
Power = 90 MW	Power = 135.2 MW

For post expansion scenario to meet the existing as well as new units steam and power requirements the following options were considered.

Post expansion steam & power scenario:-

VHP Steam = 24 TPH

MP Steam= 253 TPH

LP Steam= 179 TPH

Power= 225.2 MW

CPP configuration required (Existing 3 GTs Running):-

Power available through existing 3 GTs: 63.9 MW

Steam from CO Boilers: 51.7 TPH @36 kg/cm²g (Considering FCC II running at 59%)

Steam available from existing IBH boilers: 75 TPH @ 36 kg/cm²g

Steam available from existing 3 HRSG: 180 TPH @ 10 kg/cm²g

Additional Steam required: (-) 102.7 TPH @ 36 kg/cm²g

73 TPH @ 10 Kg/cm² g

179 TPH @ 3 kg/cm² g

Additional Power Required: 161.3 MW

To meet additional power and steam requirement following is proposed:

- 2 GTs Frame VI of 33 MW ISO Capacity
- 2 Number of HRSG of 110 TPH design capacity @100 kg/cm²g
- 1 working +1standby Boiler of Capacity 225 TPH @ 36 kg/cm²g
- **1 Number 33 MW Double Extracting STG.**

- Extracting 73 TPH of steam @ 100 kg/cm² g to steam @ 10 kg/cm² g: 9 MW
- Extracting 147 TPH of Steam @ 100 kg/cm² g to steam @ 3 kg/cm²g: 24 MW
- **1 Number 33 MW Extraction cum Condensing STG**
 - Extracting 33 TPH of steam @ 36 kg/cm² g to steam @ 3 kg/cm² g: 3.3 MW
 - Condensing 141 TPH of Steam @ 36 kg/cm² g to Condensate: 29.7 MW
- **1 Number 33 MW Total Condensing STG**
 - Condensing 154 TPH of Steam @ 36 kg/cm² g to Condensate: 33 MW

CPP CONFIGURATION FOR 2 GTG+ POWER IMPORT CASE

Existing CPP Configuration:

GTG	ISO Capacity (MW)	Operating Capacity (MW)	HRS Generation (TPH) @ MP level (10 kg/cm ² g, 250 deg.C)
4 Frame - V	25 Each	4 X 21.3	4 X 60
2 Frame - III	9 Each	2 X 7.18	2 X 27
Total		99.6	294

Frame III GTGs are considered for scrapping. Therefore, will not be considered in overall configuration post VRMP.

Existing Boiler detail:

Boiler data	Design capacity	Operating capacity	Temperature
IBH - 9	84.92 TPH, 36 KG/CM ² G.	75 TPH, 36 KG/CM ² G.	360 deg.C
IBH - 10	84.92 TPH, 36 KG/CM ² G.	75 TPH, 36 KG/CM ² G.	360 deg.C
New CO-Boiler	40.0 TPH, 38 KG/CM ² G.	40 TPH, 36 KG/CM ² G.	360 deg.C
OLD CO-Boiler	20.0 TPH, 36 KG/CM ² G.	18 TPH, 36 KG/CM ² G.	360 deg.C
WIL 8	63 TPH, 28 KG/CM ² G.	50.0 TPH, 28 KG/CM ² G.	285 deg.C
BHPV	50.0 TPH, 30 KG/CM ² G.	50.0 TPH, 28 KG/CM ² G.	285 deg.C

WIL 8 and BHPV boilers operating at 28 kg/cm² G level are considered for scrapping. Therefore, will not be considered in overall configuration post VRMP.

Steam & Power requirements:

Existing units steam & power requirement:	New units steam & power requirement :
VHP Steam = 7.5 TPH	VHP Steam = 16.5 TPH
MP Steam = 129 TPH	MP Steam = 124 TPH
LP Steam = 77 TPH	LP Steam = 73.7 TPH
Power = 90 MW	Power = 129.5 MW

For post expansion scenario to meet the existing as well as new units steam and power requirements the following option were considered.

Post expansion steam & power scenario:-

VHP Steam = 24 TPH

MP Steam = 253 TPH

LP Steam = 151 TPH

Power = 220 MW

CPP configuration required (Existing 2 GTs Running):-

Power available through existing 2 GTs: 42.6 MW

Steam from CO Boilers: 51.7 TPH @ 36 kg/cm²g (Considering FCC II running at 59%)

Steam available from existing IBH boiler: 75 TPH @ 36 kg/cm²g

Steam available from existing 2 HRSG: 120 TPH @ 10 kg/cm²g

Additional Steam required: (-) 103 TPH @ 36 kg/cm²g

133 TPH @ 10 Kg/cm² g

151 TPH @ 3 kg/cm² g

Additional Power Required: 177.4 MW

To meet additional power and steam requirement following is proposed:

- 1 working +1standby Boiler of Capacity 190 TPH @ 36 kg/cm²g
- **1 Number 23 MW Double Extracting STG.**
 - Extracting 134 TPH of steam @36 kg/cm² g to steam@ 10 kg/cm² g: 8 MW
 - Extracting 151 TPH of Steam @36 kg/cm² g to steam @ 3 kg/cm²g: 15MW

Balance Power to be imported from Grid= 155 MW

All the new & existing steam headers shall be interconnected at appropriate location for flexibility purpose. This shall be considered while preparing BDEP and detail engineering.

7.5.11 CONDENSATE SYSTEM

Steam is being used in the refinery as process steam motive fluid for the steam turbine drives, for heating etc. Condensate results from the condensing steam turbine drives, steam re-boilers and ejector condensers. Within the each individual units suspect condensate and pure condensate shall be segregated. Depending upon the requirements, each unit shall have separate header for these two condensates. The suspect condensate shall be required to be treated in centralised condensate polishing unit before use. Pure condensate shall be directly used for steam generation.

The condensate being generated which shall be recovered can be categorized under following headings:-

- Condensate coming from the exchangers, which may be consuming either MP or LP steam.
- Individual units generating MP level condensate shall flash it to LP level, cool the condensate to the required temperature of 90 °C and supply the condensate at their respectively B/L. A single condensate header shall be routed through the refinery for collection of this condensate. This condensate will then flow to the respective Deaerators under header pressure control and flow control respectively. Deaerators have been considered in CPP, HGU.
- Condensate obtained from the steam drives in the process unit.
- Any such condensate will need to be pumped to the respective LP condensate header, after appropriate polishing, if required.
- The contaminated condensate from various units.

The condensate recovered as per point number (a) to (d) shall meet the specifications of pure condensate. In order to utilise the condensate collected as per point number (e) above for steam generation, it shall be routed through a condensate polishing unit.

Table 7.5.22: Condensate Generated from VRMP Units (TPH)

Unit	No Power Import Case		2 GTGs+ Power Import	
	Suspect	Pure	Suspect	Pure
CDU/VDU	0	0	0	0
New ISOM	0.3	41.4	0.34	41.43
FC HCU	33.4	14.2	33.35	14.21
SDA	0.0	0.0	0	0
SHCU	0.0	0.0	0	0.00
HGU	2.5	333.1	2.51	333.1
PRU	10.6	0	10.6	0
SWS I	0.1	40.7	0.142	40.7
SWS II	0.0	67.5	0	67.5
SRU	0.0	22.8	0	22.8
SR LPG TREATER	0.0	0.1	0	0.063
ARU	0.3	85.8	0.28	85.82
CPP (Surface condensate)	0	310	0	0
Total	47.2	915.6	47.2	605.6

Note:

- Condensate recovery from OSBL storage and utility generation facility is not envisaged due to low quantity of condensate.
 - Suspect condensate generated from tracing steam is 9 TPH.
 - Condensate Recovery in No Power Import Case = $(915.6)*0.9+47.2*0.6=852$ TPH
 - Condensate Recovery in 2 GTG+Power Import Case= $(605.6)*0.9+47.2*0.6=573$ TPH
- * 90% of continuous pure and surface condensate (from steam turbines) and 60% of the continuous suspect condensate shall be taken as condensate return for estimating DM plant capacity with normal condensate generation.

Condensate Recovery

Both the process and surface condensate in the refinery shall be recovered and routed back to the steam generation system. Pure condensate from steam turbines surface condensers, expected to be clean will be utilised directly for steam generation. Condensate polishing is envisaged for the process condensate from reboilers etc. Only pure condensate return will be considered for fixing the capacity of demineralised water plant. Condensate contamination will be detected by stipulating on-line conductivity/pH analyzers with automated provision for drainage.

Condensate polishing unit

Condensate polishing system shall be provided for suspect condensate recovered from process units.

Normal Suspect Condensate Generation, TPH= (47.2+9) =56.2 TPH

Design Condensate Load, 10% Margin= 56.2*1.1= 62 TPH

Design capacity in m³/hr= 62/0.967= 64 m³/hr

Two trains of ~65 m³/hr each.

Table 7.5.23: Condensate polishing system:

Condensate Polishing unit	
	Same for both cases
No. units	1w+1s
Capacity	65 m ³ /hr
Preheat exchangers	2
Oil coalescers	2
Activated carbon filters	4 w + 2 s
Mixed bed	2 w + 1 s
Storage Tank for suspect condensate (1+1)	2480 m ³
Storage Tank for pure/surface condensate (1+1)	5370 m ³

System components:

Broadly the CPU plant will consist of the following:

- Two preheat exchangers
- Two oil coalescers
- (4+2) Activated Carbon filters (ACF)
- (2+1) Mixed bed (MB)
-

7.5.12 INTERNAL FUEL OIL AND FUEL GAS SYSTEM

The fuel requirement of refinery complex would be met by the internal fuel oil and the fuel gas system. Fuel is consumed only in Process units. Total requirement of fuel in all the furnaces within the process units would be met mostly by fuel gas system and partly by internal fuel oil systems. All the furnaces shall be designed for dual firing. The existing fuel network shall be integrated with the new fuel network. The adequacy of existing IFO system to cater the requirement of VRMP also shall be checked during design stage.

Fuel Demand

The total duty (MMKcal/Hr) of respective units under VRMP, considering all units running at design capacity, is indicated in the Table-7.5.24.

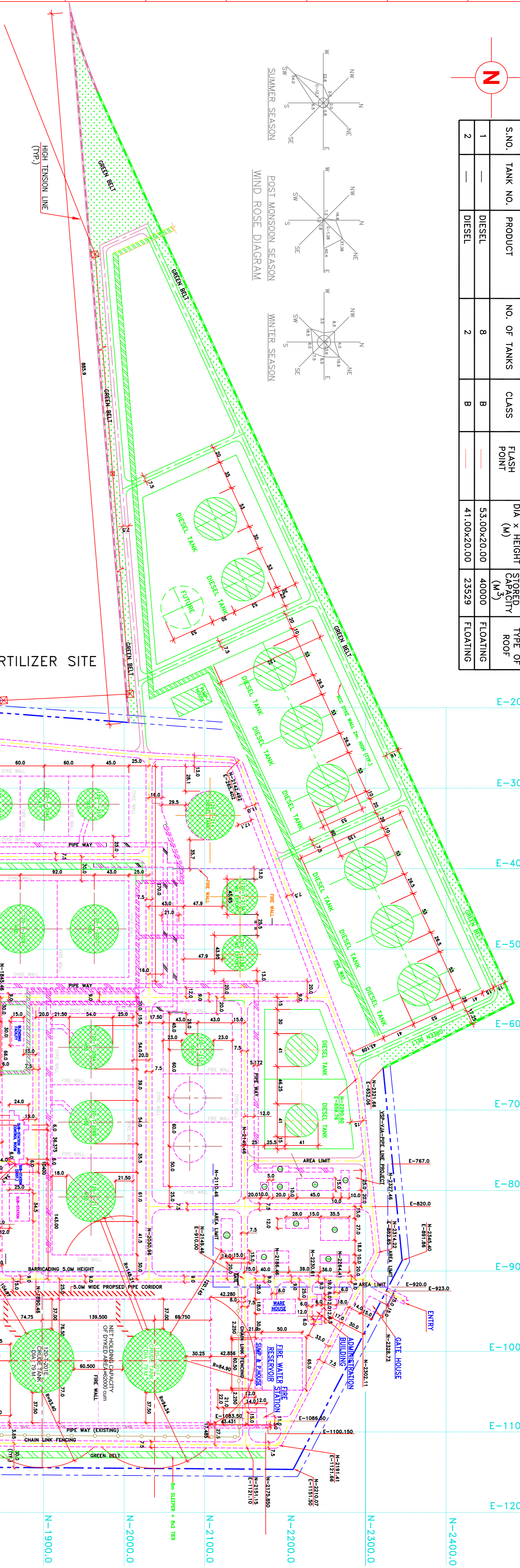
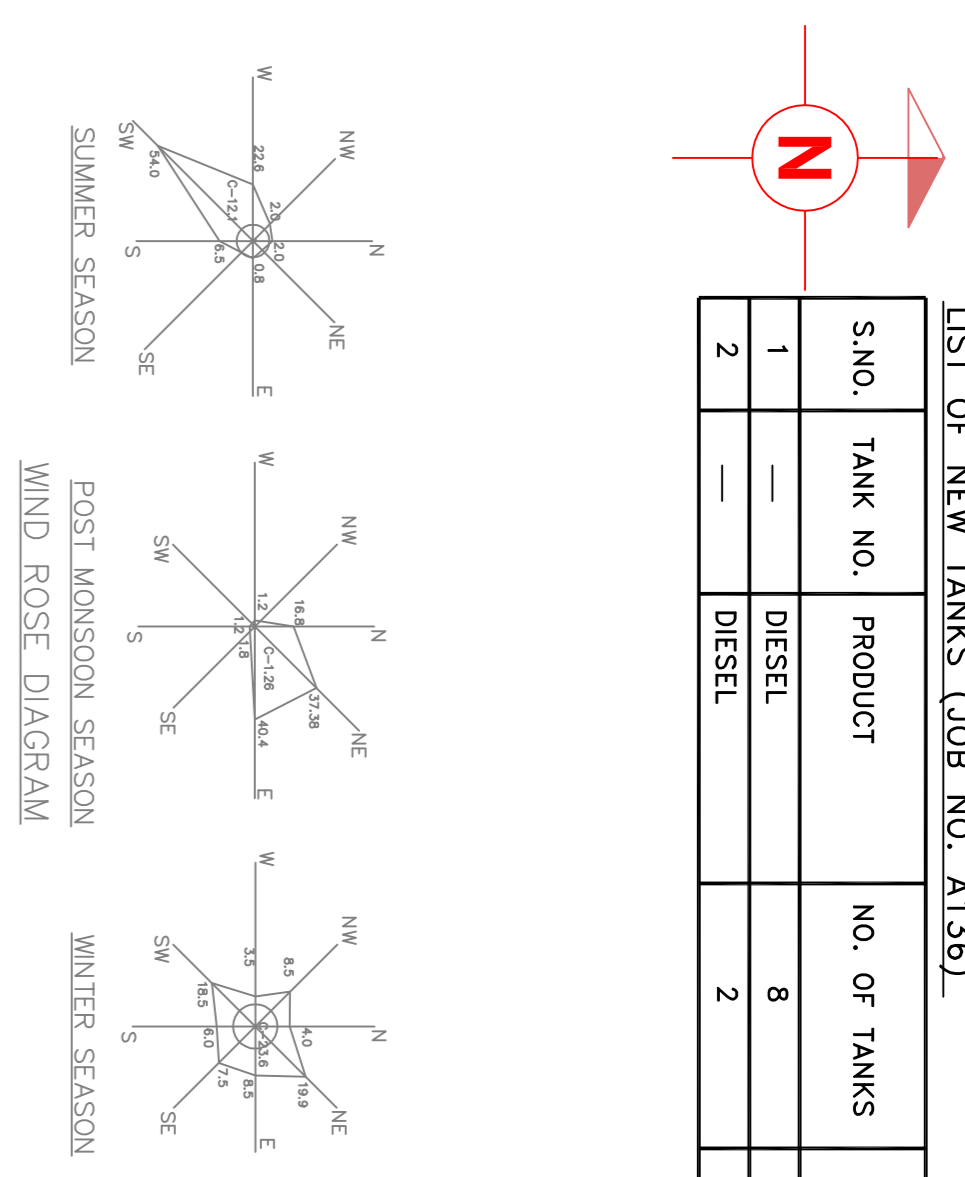
Table 7.5.24: Duty requirement for VRMP (MMKcal/Hr.)

	Unit Name	No Power Import Case	2 GTGs+ Power Import
A	Main Processing Unit		
1	CDU / VDU	130	130
2	FC HCU	95	95
3	DHDT Revamp	6	6
4	New ISOM	0	0
5	NHT Revamp	8	8
6	CCR Revamp	23	23
7	SHCU	88	88
8	SDA	43	43
B	Auxiliary Units		

	Unit Name	No Power Import Case	2 GTGs+ Power Import
1	Sulphur Recovery Unit	80	80
C	Utility		
1	Boiler	197	156
	Total :	670	629
	Total with 10% margin:	737	692

S.NO.	TANK NO.	PRODUCT	NO. OF TANKS	CLASS	FLASH POINT	DIA x HEIGHT (M)	FOUND CAPACITY (M ³)	TYPE OF ROOF
1	---	DIESEL	8	B	---	53.00x20.00	40000	FLOATING
2	---	DIESEL	2	B	---	41.00x20.00	23529	FLOATING

LIST OF NEW TANKS (JOB NO. A136)



LIST OF EXISTING TANKS UNDER JOB A638

Sl. No.	Service	Tank No.	Class	Type	Dia	Length
1	Water	W-1	A	ATP	15.0	15.0
2	Water	W-2	A	ATP	15.0	15.0
3	Water	W-3	A	ATP	15.0	15.0
4	Water	W-4	A	ATP	15.0	15.0
5	Water	W-5	A	ATP	15.0	15.0
6	Water	W-6	A	ATP	15.0	15.0
7	Water	W-7	A	ATP	15.0	15.0
8	Water	W-8	A	ATP	15.0	15.0
9	Water	W-9	A	ATP	15.0	15.0
10	Water	W-10	A	ATP	15.0	15.0
11	Water	W-11	A	ATP	15.0	15.0
12	Water	W-12	A	ATP	15.0	15.0
13	Water	W-13	A	ATP	15.0	15.0
14	Water	W-14	A	ATP	15.0	15.0
15	Water	W-15	A	ATP	15.0	15.0
16	Water	W-16	A	ATP	15.0	15.0
17	Water	W-17	A	ATP	15.0	15.0
18	Water	W-18	A	ATP	15.0	15.0
19	Water	W-19	A	ATP	15.0	15.0
20	Water	W-20	A	ATP	15.0	15.0
21	Water	W-21	A	ATP	15.0	15.0
22	Water	W-22	A	ATP	15.0	15.0
23	Water	W-23	A	ATP	15.0	15.0
24	Water	W-24	A	ATP	15.0	15.0
25	Water	W-25	A	ATP	15.0	15.0
26	Water	W-26	A	ATP	15.0	15.0
27	Water	W-27	A	ATP	15.0	15.0
28	Water	W-28	A	ATP	15.0	15.0
29	Water	W-29	A	ATP	15.0	15.0
30	Water	W-30	A	ATP	15.0	15.0
31	Water	W-31	A	ATP	15.0	15.0
32	Water	W-32	A	ATP	15.0	15.0
33	Water	W-33	A	ATP	15.0	15.0
34	Water	W-34	A	ATP	15.0	15.0
35	Water	W-35	A	ATP	15.0	15.0
36	Water	W-36	A	ATP	15.0	15.0
37	Water	W-37	A	ATP	15.0	15.0
38	Water	W-38	A	ATP	15.0	15.0
39	Water	W-39	A	ATP	15.0	15.0
40	Water	W-40	A	ATP	15.0	15.0
41	Water	W-41	A	ATP	15.0	15.0
42	Water	W-42	A	ATP	15.0	15.0
43	Water	W-43	A	ATP	15.0	15.0
44	Water	W-44	A	ATP	15.0	15.0
45	Water	W-45	A	ATP	15.0	15.0
46	Water	W-46	A	ATP	15.0	15.0
47	Water	W-47	A	ATP	15.0	15.0
48	Water	W-48	A	ATP	15.0	15.0
49	Water	W-49	A	ATP	15.0	15.0
50	Water	W-50	A	ATP	15.0	15.0

FACILITIES / BUILDINGS FOR VZAO DESPATCH TERMINAL(EXISTING)

1	BOOSTER PUMP
2	METERING SUMP
3	SCRAMPER LAUNCHER
4	PUMP HOUSE
5	CONTROL ROOM
6	SUB STATION
7	WARE HOUSE
8	ADMINISTRATION BUILDING
9	SPACE FOR SWAMP PUMP, AMBIBOR DOSING
10	SPACE FOR FUTURE D.O. SET

OFFSITES FACILITIES ADDED UNDER JOB NO. 6341

Sl. No.	PUMP NO.	SERVICE	No. OF PUMPS	REMARKS
1.	120-P-2017/F	GRADE	TWO	NEW IN PUMP HOUSE-III

LIST OF BLENDING FACILITIES (EXISTING)

- DYE INJECTION FACILITIES
- ANTI-OXIDANT FACILITIES
- MULTI-FUNCTIONAL ADDITIONAL FACILITIES (MFA)
- ANTI-STATIC ADDITIONS FACILITIES FOR ATF

OFFSITES FACILITIES ADDED UNDER JOB NO. 6341

Sl. No.	PUMP NO.	SERVICE	No. OF PUMPS	REMARKS
1.	120-P-215A	HSD	1	PUMP HOUSE-I (WEST SIDE EXTENSION)
2.	120-P-216A/B	REF/JMS EXP.	2	PUMP HOUSE-I (EAST SIDE EXTENSION)
3.	100-P-101A/B/C	DMS TRANSFER PUMPS	3	(NORTH OF STILL TANK)

BUILDINGS

- 138B-STATION-34,525.0
- 2 PUMP HOUSE-I EXTENSION ON EAST SIDE-4,091.0
- 3 PUMP HOUSE-I EXTENSION ON WEST SIDE-12,000.0

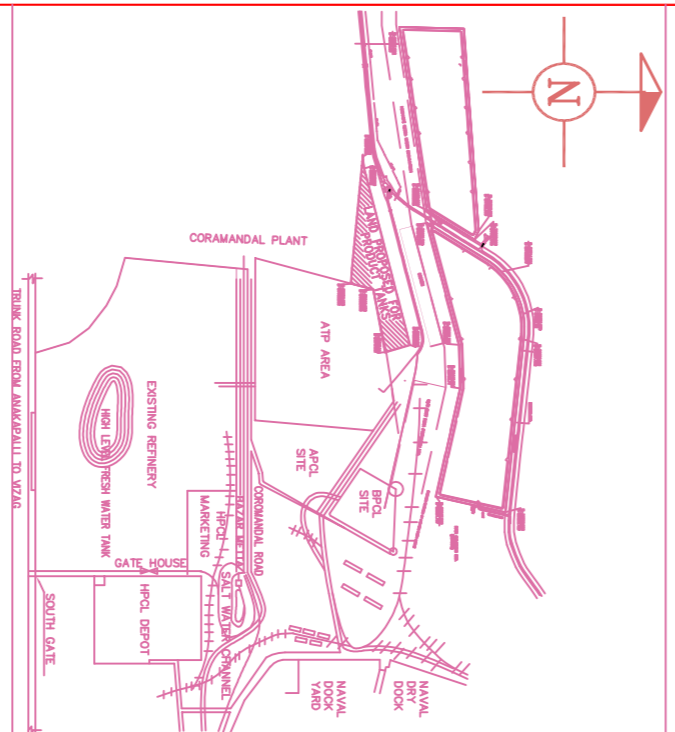
REF. DWG. NO.

REFERENCE DRAWING TITLE

- NOTES:-
- ALL DIMENSIONS AND CO-ORDINATES ARE IN METRES.
 - ROAD WIDTH SHOWN IS INCLUSIVE OF BERMS.
 - HIGH FLOOD OF THE AREA IS 3.1 m ABOVE MSL.
 - EXISTING CONTROL ROOM AND SUB STATION SHALL BE USED FOR EXPANSION.
 - EXISTING HT LINE SHALL BE BURIED/ROUTED.

LEGEND:

- EXISTING FACILITIES
- PROPOSED FACILITIES
- EXISTING FACILITIES TO BE UTILISED



ENGINEERS INDIA LIMITED

HINDUSTAN PETRO. CO. LTD.

OVERALL PLOT PLAN

SCALE	JOB NO.	UNIT	DNV/DEPT.	DWG. NO.	REV.
1:2000	A/6	3/8	0/0	1/6	4/7/0/0/2/0