Legend:
- **300** — Air Pollutant Concentration
- **– – –** — Property Line

Map labels (place names):
Come By Chance River, Goobies Siding, Goobies, North Harbour River, North Harbour River, Caplin Cove, Darby Creek, Black River, Black River, Goose Cove, Garden Cove, North Harbour, Jeffrey Cove, Maggotty Cove, Baker Cove, Catens Cove, Muddy Hole, Woody Island, Back Cove, Hardy Cove, Middle Cove, Placentia Bay, Holletts Cove, Doughboy Cove, Come By Chance River, Come By Chance, Cobb, Come By Chance Gut, Coopers Cove, Sunnyside, Centre Cove, Little Mosquito Cove, Bull Arm, Big Mosquito Cove, Stock Cove, Wreck Cove, Brinson Cove, Southern Harbour Pond, Jack's Pond Provincial Park, Arnold's Cove, Bordeaux Gut, Great Southern Harbour, Jacks Pond Brook, Little Southern Harbour, Little Southern Harbour, La Manche Bay

Project / Projet: **NLRC**

Title / Titre:
Figure 16
Maximum Annual Average Predicted Benzene Concentration (µg/m³) in Ambient Air

Échelle / Scale: 0 — 1,5 — 3km

No. projet / Project #: **722665**

Consultant — Directeur de projet / Project Director: **Jean-Luc Allard**

Consultant: **SNC·LAVALIN Environment**

Air Dispersion Model: CALPUFF
Meteorology: 2002
Air Quality Standard: N.A.
Note: these results do not include background concentrations

No.	aaaa/mm/jj yyyy/mm/dd	Description	Dessiné/Drawn	Vérifié/Verified
02	2007/07/16	Final	H. Dubois	E. Delisle
01	2007/07/05	Preliminary	H. Dubois	É. Delisle

Envir01 :\INTC\722665-NLRC\Carto\ArcGIS\1ProjetMXD\Rapport\NLRC_Fig16_Benz_MaxAvgAn.mxd

4. AIR QUALITY MONITORING AND FOLLOW-UP

NLRC has committed to install air quality monitors in the study zone. Our monitoring network will be complementary to the existing NARL network (Sunnyside, Come-by-Chance, etc.). NLRC committed during public meetings to install monitoring stations at the following locations: Goobies, North Harbour and the property limit. Additional locations may be needed. Also, a specific study related to the analysis of the air monitoring network will be made at the detailed engineering phase.

Air monitoring stations will be installed early in the construction phase to provide a project baseline and will be used to supply continuous monitoring of local air pollutants and determine compliance with operating permits and the results of air quality modeling.

The air quality monitoring plan will be developed in consultation with regulators and the Community Liaison group.

4.1 Emissions rate validation

During the detailed engineering phase, the emission rates given in Table 6 will be validated through engineering calculations and manufacturers data and the atmospheric dispersion study revised as needed.

These emission rates will also be validated at the plant start-up through a detailed stack testing program.

5. __CONCLUSION__

The air quality impact assessment was made using the best information available to estimate the overall atmospheric emissions using a conservative approach.

These estimates are realistic and allow NLRC to proceed with the atmospheric dispersion study.

With regards to predicted concentrations in communities, all results remain well below NL DEC air quality regulations, even when adding maximum estimated background concentrations due to other sources.

At the coastline or property line to the south and south-east of the proposed refinery, predicted short-term (1 hour to 24-hour) average concentrations of NO_2 and SO_2, could reach levels about 80-85% of the air quality standards. However, if these maximum concentrations were effectively observed, their frequency of occurrence would be very low. These results are based on a cautious or worst-case emission scenario during normal operation of the proposed refinery, which considers maximum permitted NOx levels and the maximum sulfur content of the fuel oil specification.

Based on these results, we conclude that the proposed refinery will comply with all applicable regulations.

6. REFERENCES

EarthTech, 2000a, <u>A User's Guide for the CALMET Meteorological Model</u>, EarthTech, January 2000.

EarthTech, 2000b, <u>A User's Guide for the CALPUFF Dispersion Model</u>, EarthTech, January 2000.

Appendix A

Emission Estimation Summary

1. ATMOSPHERIC EMISSIONS ESTIMATE AT NLRC REFINERY

In the refinery, crude oil is converted into a large variety of products, such as hydrocarbon fuels and feedstocks for the petrochemical industry. Crude oil will be transported to the refinery by marine vessel. The refined petroleum products will be exported by marine vessels.

Refining operations consist of separation processes, conversion processes, treating processes, feedstock and product handling, and associated auxiliary operations. The flow scheme of the NLRC refinery is determined by the composition of the crude oil and the chosen slate of products. The NLRC refinery's flow scheme is presented in Figure A-1.
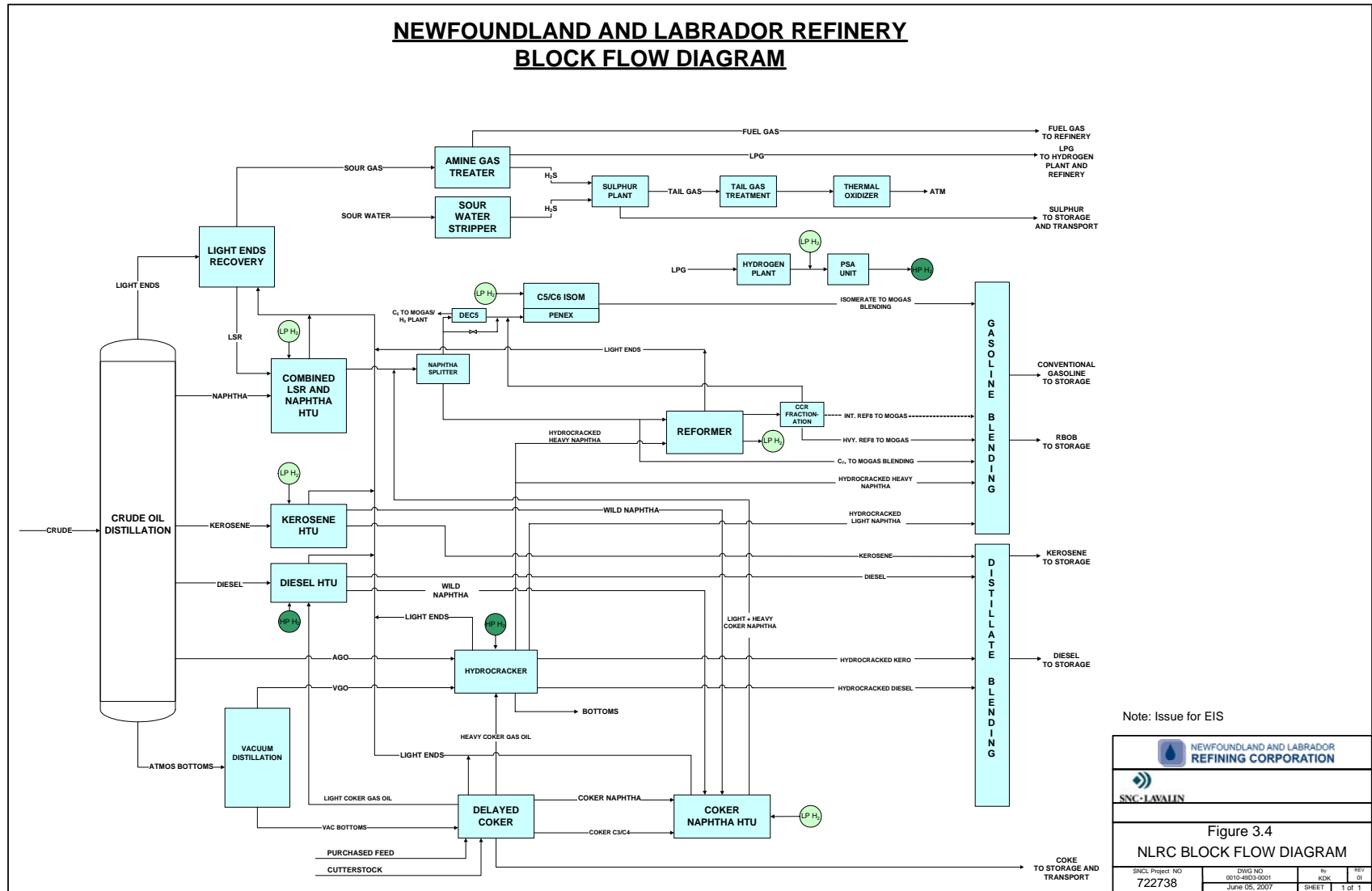
The operations associated with petroleum refining are described more fully in the following sections. Refining operations (separation, conversion, and treating) are discussed first, followed by a brief discussion of auxiliary operations, including wastewater treatment and cooling towers. Handling operations are discussed last and include equipment (tanks, pipes, pumps, and valves) employed throughout the refinery. In general, emission sources are either those resulting from the petroleum products (namely, VOC emissions) or those resulting from combustion sources at the refinery.

Volatile organic compound emissions from refinery operations can be characterized as of two types: process point source emissions and fugitive emissions. Process point source emissions are those emissions directly associated with or generated by a process unit. Process vents are an example of a point source emission. Fugitive emission sources are VOC emission sources not specifically generated by a particular process unit. Such emission sources are found throughout a refinery and may or may not be associated with a process unit. They include valves, flanges, pump and compressor seals, cooling towers, storage tanks, transfer operations, and wastewater treatment systems. Fugitive emissions also result from the evaporation of leaked or spilled hydrocarbon liquid and gases. Combustion sources at refineries result in emissions of SO_2, NO_x, CO, and particulate matter.[1]

GHG emissions were estimated to take account of future Federal and Provincial regulations. NLRC's GHG management plan is presented in Appendix C.

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[1] Air Pollution Engineering Manual, Air & Waste Management Association, edited by Anthony J. Buonicore and Wayne T. Davis, 1992

Figure A-1: Block Flow Diagram

NEWFOUNDLAND AND LABRADOR REFINERY
BLOCK FLOW DIAGRAM

Note: Issue for EIS

NEWFOUNDLAND AND LABRADOR REFINING CORPORATION

SNC·LAVALIN

Figure 3.4
NLRC BLOCK FLOW DIAGRAM

SNCL Project NO	DWG NO 0010-49D3-0001	By KDK	REV 01
722738	June 05, 2007	SHEET	1 of 1

1.1   Methodologies Used To Estimate Pollutant Emission Rates

1.1.1   Storage Tanks

A refinery tank farm can be a significant source of VOC emissions. These emissions are a function of tank type, liquid characteristics, weather conditions and annual throughput. US EPA TANKS software was used to obtain estimates of VOC and benzene emissions from storage tanks.

1.   The product types considered in this study are classified under six main categories:

- crude oil
- intermediates
- buffer/blending
- product
- fuel oil
- sour water.

Except for the two crude oils (Arabian heavy and Arabian medium) mixture compositions were not available. Typical compositions given in TANKS were used for all other product types. Conventional gasoline and the Reformulated Blendstock for Oxygenate Blending (RBOB gasoline) benzene specifications were used in TANKS. These benzene concentrations were lower than the speciated benzene fraction given in Table 15-8 of the CPPI Code of Practice[2], for emissions of benzene from TVOCs in a storage terminal.

2.   The input parameters for the TANKS software included:

- the tank dimensions (height, diameter)
- tank description and contents
- yearly turnover of product in each tank
- liquid surface temperature
- roof type (spherical, internal floating roof and fixed roof vertical storage tanks)
- number of tanks

3.   Meteorological data over 5 years (Head of Placentia Bay, 2002 to 2006) were also entered into the software in estimating the emissions from the storage tanks. Meteorological input data include:

- the local average atmospheric pressure
- solar insulation factor
- the monthly average of the maximum and minimum daily temperatures
- average wind speeds

Some of the storage tanks will contain liquids at higher than ambient temperature and contain intermediary products used in the refining operations.

---

[2] Code of Practice for developing an emission inventory for refineries and terminals, revision 10, 2006, Canadian Petroleum Products Institute.

4. In order to account for emissions for storage tanks containing liquids at higher than ambient temperature, it was necessary to assume and create an artificial meteorological file with average ambient temperatures matching those of the tank conditions, along with all the other meteorological input data taken as is. This is consistent with the EPA / API methodology that defines the TANKS software.

5. The following assumptions for emission calculations were made in using TANKS:
    a. No emissions were calculated from spherical tanks except for fugitive emissions.
    b. For fixed roof tanks:
        i.   Maximum liquid height calculated from normal operating volume;
        ii. Mean height is 50% of maximum liquid height;
        iii. Roof is conic, with a slope of 0.0625;
        iv. External shell is white and in good condition.

6.   For internal floating roof tanks:
   - Storage tanks have internal columns for roof support;
   - Internal walls condition in TANKS set to "light rust";
   - Column diameters unknown, and number of columns suggested by TANKS;
   - External shell and roof surface are white and in good condition;
   - Primary seal is "vapor mounted" and secondary seal is "rim mounted";
   - Bridge is "welded" and its fittings are "typical";
   - For artificial meteorological file, for hot tanks, the minimum, maximum and average annual temperatures were set at 34.5oF, 140oF and 87oF, respectively.

Annual calculated total losses of VOC and benzene are presented in Table II. Sour water storage tanks produce emissions of hydrogen sulphide and ammonia. The VOC emissions from sour water tanks are expected to be negligible.

The selection of tank type for each application was based on the CCME Environmental Guidelines for Controlling Emissions of Volatile Organic Compounds from Aboveground Storage Tanks. This ensures that Best Available Technology is applied to the atmospheric storage tanks to ensure than emissions from tank farm operations are minimized.

Table I: Input parameters considered in the TANKS software

Tank Description	Representative TANKS Component	Average Liquid Surface Temperature (°F)	Diameter (ft)	Height (ft)	No. of Tanks	Unit Normal Operating Volume (bbl/tank)	Total Normal Operating Volume (bbl)	Roof Type	Turnover (per yr)
Crude	Crude Oil (RVP 5)	42	260	60	12	500,000	6,000,000	Internal Floating Roof	18.25
Product									
Conventional Gasoline	Gasoline (RVP 10)	42	260	60	2	503,468	1,006,936	Internal Floating Roof	26.07
RBOB Gasoline	Gasoline (RVP 9)	42	220	60	2	345,828	691,656	Internal Floating Roof	26.07
Diesel	Distillate Fuel Oil No. 2	42	260	60	4	518,196	2,072,784	Fixed Roof	26.07
Kerosene	Jet Kerosene	42	240	60	2	431,690	863,380	Fixed Roof	26.07
Buffer / Blending									
BenSat Product	Gasoline (RVP 10)	87	150	48	1	136,500	136,500	Internal Floating Roof	1
Basestock	Gasoline (RVP 10)	87	180	48	2	170,063	340,125	Internal Floating Roof	1
Reformate	Gasoline (RVP 10)	87	150	48	1	112,546	112,546	Internal Floating Roof	1
Isomerate	Gasoline (RVP 10)	87	90	48	1	42,000	42,000	Internal Floating Roof	1
Intermediate									
Naphtha Intermediate	Gasoline (RVP 10)	87	200	60	1	270,000	270,000	Internal Floating Roof	1
Coker Naphtha Intermediate	Gasoline (RVP 10)	87	160	48	1	135,000	135,000	Internal Floating Roof	1
Naphtha / Distillate Swing	Gasoline (RVP 10)	87	200	60	1	270,000	270,000	Internal Floating Roof	1
VGO Tank	Distillate Fuel Oil No. 2	87	200	60	3	270,000	810,000	Fixed Roof	1
Coker Gas Oil Intermediate	Distillate Fuel Oil No. 2	87	200	60	1	270,000	270,000	Fixed Roof	1
Kerosene / Diesel Intermediate	Jet Kerosene	87	200	60	1	270,000	270,000	Fixed Roof	1
Light Slop	Gasoline (RVP 10)	87	140	48	1	90,000	90,000	Internal Floating Roof	1
Heavy Slop	Distillate Fuel Oil No. 2	87	140	48	1	90,000	90,000	Fixed Roof	1
Fuel Oil									
Fuel Oil	Residual Fuel Oil No. 6	160	220	48	2	260,400	520,800	Fixed Roof	26.00
Coker Feed	Residual Fuel Oil No. 6	160	240	48	2	315,000	630,000	Fixed Roof	17.38
Sour Water									
Sour Water Storage Tank		42	150	60	2	170,000	340,000	Fixed Roof	1

Table II: VOC and Benzene Annual Emissions from Tanks

Tank Description	Representative TANKS Component	No. of Tanks	Annual losses (lbs/tank)	Total Annual Losses (t)	Benzene Annual losses (lbs/tank)	Benzene Total Annual Losses (t)
Crude – Arabian heavy	Crude Oil (RVP 5)	6	5957	16.2	17.45	0.047
Crude – Arabian medium	Crude Oil (RVP 5)	6	5632	15.3	30.76	0.084
Product						
C3 LPG	N/A	2	0	0	0	-
C4 LPG	N/A	2	0	0	0	-
Conventional Gasoline	Gasoline (RVP 10)	2	17153	15.5	30.48	0.028
RBOB Gasoline	Gasoline (RVP 9)	2	10672	9.7	23.64	0.021
Diesel	Distillate Fuel Oil No. 2	4	7186	13.0	16.87	0.031
Kerosene	Jet Kerosene	2	7776	7.0	60.76	0.055
Buffer / Blending						
BenSat Product	Gasoline (RVP 10)	1	19889	9.0	48.01	0.022
Basestock	Gasoline (RVP 10)	2	29953	27.1	72.3	0.066
Reformate	Gasoline (RVP 10)	1	19888	9.0	48	0.022
Isomerate	Gasoline (RVP 10)	1	12404	5.6	29.94	0.014
Intermediate						
Naphtha Intermediate	Gasoline (RVP 10)	1	34409	16	83.06	0.038
Coker Naphtha Intermediate	Gasoline (RVP 10)	1	25733	12	62.11	0.028
Naphtha / Distillate Swing	Gasoline (RVP 10)	1	34409	16	83.06	0.038
VGO Tank	Distillate Fuel Oil No. 2	3	27401	37	50.58	0.069
Coker Gas Oil Intermediate	Distillate Fuel Oil No. 2	1	27401	12.4	50.58	0.023
Kerosene / Diesel Intermediate	Jet Kerosene	1	35323	16.0	216.55	0.098
Light Slop	Gasoline (RVP 10)	1	18869	8.5	45.54	0.021
Heavy Slop	Distillate Fuel Oil No. 2	1	11709	5.3	21.62	0.010
Fuel Oil						
Fuel Oil	Residual Fuel Oil No. 6	2	416	0.38		0.000
Coker Feed	Residual Fuel Oil No. 6	2	397	0.36		0.000
Sour Water*						
Sour Water Storage Tank		2	14654	13		-
Total				**251**		**0.71**

*H_2S and NH_3 emissions

1.1.2   Process Unit Emissions Via Stacks

Process units that are emission sources of the pollutants covered in the study include:

- Hydrocracker
- Diesel HTU
- Kerosene HTU
- Naphtha HTU
- Coker Naphtha HTU
- Atmospheric and Vacuum Distillation
- Utility Plant
- Hydrogen Plant
- Reformer
- Delayed Coking
- Acid Gas Flare Stack
- High Pressure Flare Stack
- Low Pressure Flare Stack

The process units and their service type, along with percent burner efficiency, burner combustion fuel source, total heat fired and head absorbed data were provided for the study (Table III). Two types of combustion fuels were specified:

- residual fuel oil No. 6 with a sulfur content of 0.7% wt and a heating value of 146,000 Btu/gal
- refinery fuel gas with a hydrogen sulfide content of 20 ppm and a heating value of 1,265 Btu/scf

Low NO_x burners will be used in the refinery. Emission factors for NO_x were selected as per Newfoundland and Labrador Regulation 39/4. US EPA AP-42 emission factors were selected from Chapter 1.3 for fuel oil combustion and Chapter 1.4 for natural gas combustion. The emission factors were selected based on varying firing configurations and on total heat fired for each burner. The total fuel required by the burners was calculated from the given data.

Table III: Input Data For Emissions Rate Calculation From The Stacks

Stack No.	Unit	Service	Qty of Fired Heaters	Heat Absorbed (MMBTU/hr)	Total Heat Fired (MMBTU/hr)	% Eff.	Fuel Type
1	Hydro cracker	Recycle Gas Htr Unit 1	1	101	113	90%	Gas
2	Hydro cracker	Product Frac Fd Htr Unit 1	1	144	160	90%	Oil
3	Hydro cracker	Recycle Gas Htr Unit 2	1	101	113	90%	Gas
4	Hydro cracker	Product Frac Fd Htr Unit 2	1	144	160	90%	Oil
5	Diesel HTU	Combined Feed Htr	1	53	59	90%	Gas
6	Kero HTU	Rx Charge Htr	1	24	27	90%	Gas
7	Kero HTU	Stripper Reboiler	1	85	95	90%	Gas
8	Naphtha HTU	Charge Htr	1	51	57	90%	Gas
9	Naphtha HTU	Stripper Reboiler	1	93	103	90%	Gas
10	Naphtha HTU	Splitter Reboiler	2	177	196	90%	Gas
11	Coker Naphtha HTU	Rx 2 Charge Htr	1	29	35	83%	Gas
12	ADU	Crude Heater	3	453	539	84%	Oil
13	VDU	Vac Heater	2	243	290	84%	Gas
14	Utility	650# Steam Boiler	2	476	567	84%	Oil
15	Utility	150# Steam Boiler	2	241	287	84%	Oil
17	H2 Plant	Reformer	1	225	268	84%	Gas
18	H2 Plant	Reformer	1	225	268	84%	Gas
19	CCR	Charge Htr, Htr 1, Htr 2, Htr 3	4	523	575	91%	Gas
21	TGT/TO	Incinerator		-	-	-	
22	Delayed Coker	Coker Htr 1	1	156	173	90%	Gas
23	Delayed Coker	Coker Htr 2	1	156	173	90%	Gas
24	Delayed Coker	Coker Htr 3	1	156	173	90%	Gas

Emission estimates of from these process units (Table IV) were made for

- SO_2 (based on method for conversion as per AP-42 recommendation)
- NO_x (expressed as NO_2)
- CO, VOC, CO_2
- CO_{2Eq} (for greenhouse gases of methane, N_2O and CO_2 emissions rolled-up)
- filterable particulate matter PM
- total condensable PM, $PM_{2.5}$, PM_{10}
- Total Organic Compounds (TOC)
- non-methane TOC
- formaldehyde and polycyclic organic matter (POM)

For SO_3, POM, NMTOC, there are no standard emission factors given in AP-42 for natural gas combustion. Neither are there standard emission factors given for VOC based on fuel oil combustion. Particle size distribution estimates for $PM_{2.5}$ and PM_{10} were made based on percentages of total PM in uncontrolled emissions, given by AP-42, Chapters 1.3 and 1.4. Furthermore, emissions of organic compounds such as n-alkanes C_2 to C_6, BTX compounds, polycyclic aromatic hydrocarbons PAH, OCDD dioxin, naphthalene and trichlorethane were also estimated based on fuel oil and natural gas combustion sources, as provided in AP-42, when applicable. Emissions of benzene were also estimated using natural gas and residual fuel oil No. 6 combustion sources. Finally, emissions of metals (18 elements) were accounted for

including lead, zinc, nickel, cadmium, mercury, chrome, etc. Emission factors for the metals were also obtained from AP-42.

Consideration will be given to combining stacks, where appropriate, for the purpose of developing the dispersion model.

Table IV: Estimation Of Emissions From These Process Units (T/Year)

Stack No.	Unit	SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	NMTOC	VOC	Benzene	CO_{2eq}
1	Hydro cracker	1.2	42	30	2.7	2.7	2.7		1.9	7.4E-04	42537
2	Hydro cracker	478	133	22	48	43	30	1.22		9.3E-04	108899
3	Hydro cracker	1.2	42	30	3	2.7	2.7		1.9	7.4E-04	42537
4	Hydro cracker	478	133	22	48	43	30	1.22		9.3E-04	108899
5	Diesel HTU	0.64	14.3	16	1.4	1.4	1.4		1.0	3.9E-04	22381
6	Kero HTU	0.29	6.5	7	0.64	0.6	0.6		0.46	1.8E-04	10164
7	Kero HTU	1.02	23	25	2.3	2.3	2.3		1.6	6.2E-04	35666
8	Naphtha HTU	0.61	13.7	15	1.4	1.4	1.4		1.0	3.7E-04	21460
9	Naphtha HTU	1.1	38	27	2.5	2.5	2.5		1.8	6.8E-04	38927
10	Naphtha HTU	2.1	73	52	4.7	4.7	4.7		3.4	1.3E-03	74078
11	Coker Naphtha HTU	0.37	8.3	9	0.83	0.8	0.8		0.60	2.3E-04	13103
12	ADU	1611	449	73	163	144	101	4.1		3.1E-03	367252
13	VDU	3.1	107	76	6.9	6.9	6.9		5.0	1.9E-03	109212
14	Utility	1694	472	77	172	151	106	4.3		3.3E-03	386142
15	Utility	858	239	39	87	76.5	54	2.2		1.7E-03	195544
16	Utility										
17	H2 Plant	2.9	99	71	6.4	6.4	6.4		4.6	1.8E-03	754638
18	H2 Plant	2.9	99	71	6.4	6.4	6.4		4.6	1.8E-03	754638
19	CCR	6.2	213	152	14	14	14		10	3.8E-03	216926
20	CCR										
21	TGT/TO	94									82401
22	Delayed Coker	1.9	64	46	4.1	4.1	4.1		3.0	1.1E-03	65327
23	Delayed Coker	1.9	64	46	4.1	4.1	4.1		3.0	1.1E-03	65327
24	Delayed Coker	1.9	64	46	4.1	4.1	4.1		3.0	1.1E-03	65327
25	Acid Gas Flare Stack										
26	High Pressure Flare Stack										
27	Low Pressure Flare Stack										
	Total	**5241**	**2394**	**949**	**584**	**521**	**386**	**13**	**47**	**2.8E-02**	**3581383**

1.1.3 Process Vents

There will be a number of process vents in both continuous and intermittent use within the refinery. Details regarding the application, number and type of vents will be developed during the engineering phases of the project. Process vents will be minimised as much as practicable. Best Available Control Technology will be applied to control emissions from process vents.

1.1.4 Process Fugitive Emissions

Fugitive Emissions are emissions of VOC due to minor equipment leaks, process upsets, sampling procedures and process turnarounds. Equipment will be selected to minimise or eliminate process fugitive emissions by the application of Best Available Technology.

Fugitive emissions are a function of equipment quantity and the emission rate of each individual piece of equipment. The equipment emission source inventory for refineries is based on data from the CPPI Code[3]. It is estimated that 196 pumps and 31 compressors will be used in the refinery. The average component count for equipment in both light liquid and gas service was obtained from Table 3-1 in the CPPI code, enabling the estimation of the source counts for emission points. The correlation factors presented in Table 3-4 of the CPPI code were then applied to obtain TOC emission estimates from fugitive emission sources. These correlations predict TOC emission rates (including non-VOCs such as methane and ethane).[4] The average emission rate from fugitive sources for each type of component was then calculated, and is presented in Table V.

The emissions for benzene were estimated based on information obtained in CPPI Code Table 15-7.   This recommends a refinery speciation profile of TVOCs, with 1.72% benzene composition (typical for TVOCs). There are no existing norms for TOC or VOC emission rates from fugitive sources, so average TOC emission rates were used, giving a more conservative approach. Emissions factors for pump seals and compressor seals were selected as zero based on the assumption that dual mechanical seals would be installed on all pumps and that the best available control technology (BACT) would be used for compressors.

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[3] Canadian Petroleum Products Institute (CPPI) "Code of Practice for Developing and Emission Inventory for Refineries and Terminals", revision 10, 2006
[4] These equations were originally provided in the "Protocol for Equipment Leak Emission Estimates EPA-453/R-95-017", November 1995 document. In order to use this method, a screening value was attributed to each process fugitive emission source. The screening value distribution for each component type was based on SNC-Lavalin Environment's (SLEI) experience in refinery processes.

Table V: Process Fugitive Emissions

Sources	Average Component Counts	Source Counts	TOC Correlations Factors kg/h/source	Average Emission kg/h	Average Emission t/year
Pumps	**196**				
Valves per pump	41	8036	$E = 2.29 * 10^{-6} * C^{0.746}$	1.05	9
Flanges per valves	4.1	32947.6	$E = 4.61 * 10^{-6} * C^{0.703}$	6.54	57
Mixer seals	1	196	$E = 1.36 * 10^{-5} * C^{0.589}$	0.06	0.5
Pump seals per pump	1.35	264.6	$E = 5.03 * 10^{-5} * C^{0.610}$	0.32	2.8
Compressors	**31**				
Valves per compressor	133	4123	$E = 2.29 * 10^{-6} * C^{0.746}$	0.54	5
Flanges per valves	4.1	16904.3	$E = 4.61 * 10^{-6} * C^{0.703}$	3.36	29
Compressor seals per compressor	2	62	$E = 1.36 * 10^{-5} * C^{0.589}$	0.02	0.16
Total organic compounds (TOC)					**104**
Benzene					**1.8**

1.1.5   Wastewater Treatment and Cooling Towers

The main sources of atmospheric emissions from the wastewater collection and treatment systems are VOCs and benzene that evaporate from the surfaces of wastewater. The control of wastewater collection and treatment system emissions involves adding vapor tight covers where emissions are greatest (e.g. such as with oil/water separators). In this study, two sources of wastewater emissions are considered:

- those from cooling towers
- wastewater treatment plants

Atmospheric emissions from cooling towers would normally consist of VOCs and some dissolved gases such as hydrogen sulfide and ammonia, which enter the cooling system from leaking heat exchangers and condensers. However, the cooling tower in this refinery is removing heat from sea water being used to cool a closed loop tempered water system. As such, the cooling tower does not contact water that contacts the refinery heat exchangers. Consequently, no VOC or other emissions are expected from the cooling tower itself. Any VOC or other emissions that might normally be expected from the cooling tower will instead come from the vent on the tempered water loop pump surge drum. The standard methodology for determining emissions from cooling towers has been used to determine the emissions rate from the cooling water vent.

Concerning wastewater treatment processes, these vary greatly by refineries, and generally include oil/water separators and air flotation.

The emissions of VOCs and benzene were estimated using emission factors and assumptions found in AP-42 and in the CPPI Code of Practice (Table VI). Table 5.1-2 of AP-42 presents multiplication factors for the estimation of VOC emissions from oil/water separators and cooling towers. In the absence of cooling water rates and wastewater flow rates, AP-42 recommends applying 40 times the refinery feed rate in the case of cooling water rates and 0.95 times the refinery feed rate for wastewater flow rates. The refinery feed rate is defined as the crude oil feed rate to the atmospheric distillation unit (ADU). The selection of the emission factors were made based on controlled emissions. CPPI code Table 7-3 provided the emission factor applied for oil/water separators. The CPPI code clearly indicates that the AP-42 factor specified for oil/water separators is not recommended and should not be applied. Emission rates for benzene from the oil/water separators were obtained using the recommended speciation profile of TVOCs in a refinery, where benzene is given as 1.72% of TVOCs. The results of the VOC emissions from the cooling towers may include emissions of H_2S and ammonia.

Table VI: Wastewater Treatment and Cooling Water System Emissions

Emissions	Units	Cooling Water System	Waste Water Treatment
Multiplication factor	-	40	0.95
VOC Emission Factor	$kg/10^3 \ m^3$	0.08	
	kg/m^3		0.0033
VOC emissions	t/year	**56**	**55**
Benzene emissions	t/year	**0.96**	**0.94**

1.1.6   Ship Loading

Loading losses occur as organic vapours in empty cargo tanks are displaced to the atmosphere by the liquid loaded into the tanks. Unloading losses are accounted for in storage tank emissions and are not covered in this section. These were accounted for in using TANKS software.   The ships will be filled with submerged lines rather than splash filled.   Ballast emissions are excluded during unloading.   It was assumed that BACT use would require double-hulled cargo ships for the transportation of product, eliminating this type of emission. Loading/unloading emissions consist mainly of VOCs including benzene.

Table VII: Input Parameters

Products	Ship type	Tonnage of VesselDWT	Number of ships/year
Crude type	VLCC	319,000	39
Crude type	Suezmax	150,000	27
Gasoline	Handymax	50,000	20
Gasoline	Handymax	40,000	8
Gasoline	Handymax	30,000	11
Kerosene	Panamax	60,000	12
Kerosene	Handymax	50,000	15
Kerosene	Handymax	40,000	18
Kerosene	Handymax	30,000	25
RBOB	Handymax	50,000	17
RBOB	Handymax	40,000	16
RBOB	Handymax	30,000	22
Diesel	Panamax	80,000	45
Diesel	Handymax	50,000	48
Sulphur	Bulk Carrier	20,000	73
Coke	Bulk Carrier	60,000	25

The input parameters include:

- the product transported
- the type of ship used
- tonnage of the vessel (in deadweight ton)
- the number of ships per year to be passing through the port

VOC emission factors for gasoline loading operations at marine terminals were taken from Table 5.2-2 of AP-42, with the assumption of a clean vessel tank. Equation 1 given in section 5.2 of AP-42 was used to calculate emissions from loading of petroleum liquids (such as kerosene and diesel fuels), applying the submerged loading saturation factor given in table 5.2-1 for marine vessels. No factors were given for coke and sulphur loading emissions. In the estimation of VOC and petroleum liquids emission rates, a recovery efficiency of 95% was applied in reducing emissions during loading operations. Total emissions for these pollutants calculated take into account this recovery efficiency. The estimation of benzene emissions were carried out by applying the specified benzene compositions in the conventional gasoline and RBOB blends, provided by the client. Thus benzene emissions represent a certain percentage of the VOC emissions, and also accounts for 95% recovery efficiencies.

Table VIII: Ship Loading Emissions

Results	Loading Operations	
	VOC (t/year)	Benzene (t/year)
Gasoline loading	1023	6.75
Petroleum liquid loading	6	0.0001
Total raw	**1029**	**7**
Gas recovery efficiency	95%	95%
Total emitted	**51**	**0.34**

1.1.7 Vessel Operations

Maritime manoeuvring operations for which emissions of pollutants were considered included approach procedures of the ship into the Head of Placentia Bay to account for the time to arrive at the site, berthing manoeuvres, emissions from loading/unloading operations, re-berthing manoeuvres, and the time to leave the Head of Placentia Bay during departure. The input information considered in the vessel operations emissions estimates was the same as with ship loading operations seen earlier. During each stage of vessel operations, emissions will vary based on various procedures used, as follows:

- Approach and departure from the site involve VOC emissions during cargo transit from the ship's storage tanks, as well as emissions of pollutants from the main engine and auxiliary engine power of the cargo ship.

- Main engine power is applied during manoeuvres such as the slow cruise during approach, berthing/re-berthing operations and departure from the site, to propel the ship.

- Auxiliary power is used mainly to power the ship's utilities and provide electricity. During berthing/re-berthing and loading and unloading operations, the power output required from the auxiliary engines is higher compared to slow cruise and departure.

- VOC losses from the storage tanks are also considered during berthing/re-berthing operations.

- The emissions of VOC and benzene during transit from gasoline blends were calculated using equation 5 in section 5-2 of AP-42. The proportion of benzene in the gasoline and RBOB blends applied were those specified by the client, to estimate benzene emissions during transit. The presence of benzene in kerosene and diesel are considered to be negligible.

- Emissions were also considered from the main engine and auxiliary engines powering the tugboats used during berthing/re-berthing operations, enabling the ship to position itself properly at the pier.

- Once at the pier, the main engine is turned off and emissions during loading and unloading result only from the auxiliary engine and the ship's boilers used to generate the steam required to power the transfer pumps.

- An EPA publication[5] was consulted to obtain the emission rate algorithms. For all pollutants for which emission rates have been estimated, the marine engine emission factor and fuel consumption algorithms given in Table 5-1 were used. The emission rates for SO2 apply a similar equation, which also accounts for fuel consumption and the sulphur content of the fuel, (all SO2 emissions are fuel derived). These emission factor and fuel consumption rate algorithms are applicable to all engine sizes. Emission rates were considered for:
  a) total hydrocarbons
  b) total PM, $PM_{2.5}$, PM_{10}
  c) NO_x (expressed as NO_2)
  d) SO_2
  e) CO, CO_2 for all stages of vessel operations with the addition of N_2O, TOC and methane emissions during loading/unloading operations

- Greenhouse gases, rolled-up as CO2EQ were calculated during loading/unloading stages mainly originating from boiler combustion and the CO2 emitted from auxiliary engine power.

- The particulate fractionation into PM2.5 and PM10 were estimated based on the percentages recommended in "Exhaust and Crankcase Emission Factors for Non-road Engine Modeling Compression – Ignition, EPA420-P-04-009", April 2004.

- The main engines are powered by heavy fuel oil with sulphur content of 2.7%, while the auxiliary engines and boilers are fed marine diesel oil containing 1.5% sulphur. The sulphur content in these two fuel sources represents a conservative approach so that the emissions will be overestimated. Normally however, as more stringent regulations limiting the content of sulphur in these types of fuels will come into effect in the coming years, the sulphur emissions will decrease.

- A boiler efficiency of 90% was applied.

- The main engine power for the cargo ships was not specified and was calculated from the bulk carriers and tankers equation given in section 5 of EPA420-P-04-009 document. The auxiliary engine loads for the ships, in different stages of the manoeuvres were specified in Table 4-6 of the EPA document. This accounts for the reduction in emissions of pollutants originating from the auxiliary engines as they are powered down at different stages of vessel operations.

- The main engine power rating for tugboats was obtained from section 5 of the document, while the auxiliary power was not specified, and was assumed to be the same as that of the cargo ship during berthing/re-berthing operations.

- The emission rates of pollutants originating from the ship's boilers were estimated based on SLEI experience. It should be noted that the cleaned flue gases generated from the boilers are assumed to be partially (36%) reused as inert gases in the cargo ship's storage tanks.

- Emission rates for benzene were estimated based on the percentage specified for the mixtures as 0.62% in the conventional gasoline, 0.69% in the RBOB blend gasoline and an average of 0.855% in the Arabian crude oil.

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[5] US EPA "Analysis of Commercial Marine Vessels Emissions and Fuel Consumption Data, EPA420-R-00-002", February 2000 edition

Table IX: Vessel Operations Emissions (t/year)

Products	SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	Benzene	$CO_{2\,eq}$
Crude	214	137	25	3.9	3.7	3.4	115	1.01	14497
Crude	106	66	11	1.9	1.8	1.6	41	0.36	7589
Gasoline	58	36	5.8	1.1	0.98	0.88	23	0.15	4390
Gasoline	24	15	2.3	0.43	0.40	0.36	7.8	0.05	9353
Gasoline	31	19	3.0	0.57	0.52	0.46	7.9	0.05	2371
Kerosene	37	23	3.7	0.67	0.61	0.56	0.48	0.01	2735
Kerosene	43	27	4.3	0.79	0.72	0.65	0.55	0.01	3243
Kerosene	52	32	5.1	0.96	0.87	0.79	0.65	0.01	3973
Kerosene	68	42	6.6	1.2	1.1	1.02	0.82	0.01	5232
RBOB	50	31	5.0	0.92	0.84	0.76	20	0.14	3795
RBOB	46	28	4.5	0.84	0.77	0.69	15	0.11	3495
RBOB	60	37	5.8	1.1	1.00	0.90	15	0.11	4592
Diesel	140	88	14	2.6	2.4	2.1	1.9	0.03	10335
Diesel	139	86	14	2.5	2.3	2.1	1.8	0.03	10502
Sulphur	197	120	19	3.6	3.3	2.9	2.2	0.04	15270
Coke	76	47	7.7	1.4	1.3	1.2	0.95	0.02	5694
Total	**1342**	**833**	**137**	**25**	**23**	**20**	**254**	**2.2**	**107066**

1.1.8 Flares

For this refinery, there will be three flare systems, one at high pressure, another at low pressure and a third for acid gas flaring. To estimate flare emissions, the total thermal release from all three flare systems were combined under one flare total thermal release that was used as input information to arrive at emission estimates. The total thermal release parameter used was 111 MMBtu/day (combining all three flare lines).

- AP-42 Tables 13.5-1 and 13.5-2 provide factors for estimating emission rates for CO, NOx and total hydrocarbons.
- The average volume composition in total hydrocarbons is presented in Table 13.5-2 and considers the emissions of methane, ethane/ethylene, acetylene, propane and propylene emissions.
- The flare gas heating value and sulphur levels in the flare gas were taken from CPPI code Appendix D and section 15.3.1.2, respectively.
- For the distribution size of particulate matter, Table 1.4-2 of AP-42 was consulted for the emission factor of filterable PM and the sample calculation for estimating flaring emissions presented in Appendix D of the CPPI code was applied to obtain the emissions of PM_{10} and $PM_{2.5}$. It is being assumed that PM_{10} and $PM_{2.5}$ emissions are 100% of PM emissions.

Table X: Flares Emissions (t/year)

	SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	Total Hydrocarbons
Total Emissions	6.2	1.25	6.8	0.035	0.035	0.035	2.6

1.2   Summary of NLRC Refinery Emissions

Table XI summarizes the overall refinery atmospheric emissions. The methodology used is conservative. It means that emissions rate overestimate the real emissions expected at plant start-up.

These estimates also use the worst-case scenario specified in the project. For example, the fuel oil used has a maximum sulphur content of 0.7 % w. In practice the actual average concentration will be lower but we decided to use the maximum value guaranteed by the fuel supplier.

These estimates are considered to be the best estimation possible at the present time (i.e. at the preliminary engineering phase). As the engineering phase progresses, all these estimates will be reviewed and are expected to reduce the value presented in Table XI.

The refinery will be engineered to use best available technologies from the petroleum industry in order to minimise atmospheric emissions at source. We will then use best available control technologies economically achievable for all significant remaining emissions.

Also during the engineering phase, an emission management program will be developed. All sources of emissions will be reviewed and detailed further as more information becomes available. At the present time, all significant sources of emissions have been reviewed. Some sources have not been detailed at this time as engineering has not progressed sufficiently to provide information on which to base an emission estimate (intermittent process vents, landfarm operations, spills, cleaning activities).

Table XI: Summary Table of Atmospheric Emissions

No	Pollutants / Source	PM Total	PM 10	PM 2.5	NOx	SO2	CO	CO2 eq	VOC	Benzene
						t/year				
1	Tanks								251	0.71
2	Stacks	584	521	386	2394	5241	949	3581383	60	0.028
3	Fugitive emissions								104	1.8
4	Waste water treatement								55	0.94
5	Discharge									
6	Cooling tower								56	0.96
7	Ship loading								51	0.34
8	Ship manoeuvring	25	23	20	833	1342	137	107066	254	2.2
9	Flares	0.035	0.035	0.035	1.2	6.2	6.8	**Note ***	2.6	
	Total	**609**	**544**	**406**	**3228**	**6589**	**1093**	**3688449**	**834**	**6.9**

* Note: To be determined at the detailed engineering phase. Flare GHG emissions will not be significant compared to the overall NLRC's GHG emissions.

Atmospheric emissions during the construction phase

ATMOSPHERIC EMISSIONS DURING THE CONSTRUCTION PHASE

Prior to the construction phase, we will prepare a general program to control atmospheric emissions of major heavy equipments.

This program will be incorporated into the contractors' specifications to make sure it is strictly enforced.

The program will include among other items:

- a dust control program;
- heavy equipment specifications to have recent equipments in good conditions (to minimize criteria air contaminants emissions);
- heavy equipment maintenance program;
- fuel oil specifications.

An environmental monitoring station will be used at the property limit to verify the compliance to ambient air quality criteria.

GHG Management plan

GHG MANAGEMENT PLAN

NLRC is committed to taking action on climate change and has considered the national and provincial plans in incorporating continuous improvement and best available technology economically achievable (BATEA) with respect to greenhouse gases (GHG) emissions in the design of the Project and the Project's Emissions Management Plan. NLRC will implement policies, designs, operating practices, and processing equipment that is mindful of the need to avoid or reduce GHG emissions and comply fully with Canada's new Clean Air Act and the Regulatory Framework for Air Emissions, within its sphere of ability to directly control or mitigate its emissions.

NLRC's Greenhouse Gas management strategy contains the following major key elements:

1. Incorporating Best Available Technologies Economically Achievable (BATEA) in the refinery's design. This involves:

   1. Maximizing the use of light (C_5-) as refinery fuel and hydrogen plant feed which will fulfill the requirements under Regulatory Framework for Air Emissions for using cleanest available fuels;

   2. Evaluating the entire refinery configuration to identify energy conservation opportunities and taking measures to enhance energy-efficiency and savings;

      a.   optimizing equipment design to minimize fugitive emissions of process streams (that includes GHGs) including: using gaskets and seals on equipment joints that are designed to eliminate leaks, use leakless designs and specify low emissions equipments

      b.   using tank vapour control and vapour recovery systems to reduce the loss of hydrocarbons to the atmosphere, and

      c.   implementing a fugitive emissions leak detection, inspection, maintenance and repair program;

      d.   minimizing flaring events through proper process control and co-ordinated maintenance

      e.   implementing burner management systems on all fired heaters to optimize heat recovery, improve combustion and reduce GHG emissions.

   3. Reviewing energy use and operational practices on a regular basis, and providing training programs for operators with focus on energy conservation, energy efficiency, reducing direct emissions under operational control.

4. Implementing a GHG monitoring and reporting program to measure GHG emissions and identify GHG reduction opportunities. Setting continuous improvement targets for energy efficiency and GHG emissions as part of the business planning cycle.

5. Reducing energy consumption within the design and operational phase of the project by:

   a.   Executing only commercially proven and reliable technologies;

   b.   Enhancing of heat exchange in preheating systems and furnace combustion;

   c.   Preferably using equipment that is known to be energy efficient;

   d.   Using high-efficiency process heaters;

   e.   Insulating equipment and piping where relevant;

   f.   Eliminating fugitive GHG emissions by using gaskets and seals on equipment joints that are specially designed to eliminate leaks; using the best available control system to reduce the loss of GHG to the atmosphere; implementing a fugitive emissions leak detection inspection and appropriate maintenance;

6. Maximizing the volume of high-quality fuel products, particularly Ultra-Low Sulphur Diesel (ULSD) that meet or exceed the stringent standards of the U.S. PADD IA and IB (Petroleum Administration for Defence Districts; Subdistrict IA (New England) and Subdistrict IB (Central Atlantic)), air shed-specific standards and European markets, both present and as projected over the coming 10-15 years. While this does not reduce the refineries emissions it has a tremendous impact on end user emission both for greenhouse gases and criteria air pollutants (CAC).

7. Considering the refinery configuration and plan to facilitate ease of CO_2 capture, providing for plot space and tie-in connections either pre- or post-combustion, when appropriate commercial technologies or CO_2 sinks become available.

8. During the construction period, NLRC will also minimise GHG and CAC emissions by implementing the following directives:

   • use recent construction equipments that are in good conditions;

- use high efficiency generators and use the existing electricity grid power as soon as possible.

- request a strict maintenance program for all heavy equipments;

- the plant will be tested for process equipment leaks (pipes, valves, etc.) prior to its start-up.

2. NLRC will implement a GHG management program, which will be consistent with the ISO series 14000 standards (which specifies requirements for environmental management systems) and particularly ISO 14064 that applies to Greenhouse gases, the Clean Air Act, and the Kyoto Protocol. Through this program, NLRC would be responsible for:

   1. Ensuring all operations and activities are managed in conformity with acceptable practices;

   2. Implementing a GHG monitoring, controlling, and reporting program to measure GHG emissions, and recognizing the opportunity for GHG mitigation;

   3. Ensuring regular evaluations to make certain that NLRC meets the regulatory framework for GHG emissions.

   4. Following –up and partaking in CO_2 markets.

   5. Encouraging the sequestering of CO_2 by enhancing biological absorption in forest by participating to forests rehabilitation or similar projects.

   6. Continuing to explore business opportunities for economic capture and storage of CO_2. NLRC is committed to maintaining and expanding their knowledge base regarding emerging carbon capture and mitigation technologies. The possibility also exists for providing technical and financial support for emerging technology application at a demonstration level or to a technological fund.

   7. Explore business opportunities for the development and use of renewable fuels.