NEW PERMIT/AMENDMENT/RENEWAL/CLOC/ALTERATION
TECHNICAL REVIEW

Permit No: **36644, PSD-TX-903, N-007** Company: **Fina Oil & Chemical Company**
Project Type: **CRVW** Facility Name: **ETHYLENE CRACKER & ASSOCIATED FACILITIES**
Record No: **54153** City: **Port Arthur**
Account No: **JE-0005-H** County: **Jefferson**

AUTHORIZATION CHECKLIST (any "Yes" requires signature by Executive Director):

Will a new policy/precedent be established?	**No**
Was at least one public hearing request received?	**No**
If yes, was/were all the request(s) withdrawn?	
Is a state or local official opposed to the permit?	**No**
If yes, please provide name and title of official.	
Is waste or tire derived fuel involved?	**No**
Are waste management facilities involved?	**No**

PROJECT OVERVIEW

Fina Oil and Chemical Company is requesting the authorization to construct a 2.2 billion pound/year ethylene cracking unit and the associated facilities (also collectively known as an olefin unit). The proposed ethylene cracking unit will include nine ethylene cracking furnaces (eight with a maximum firing capacity of 445.41 MMBtu/hr, and one at 342.5 MMBtu/hr), three heaters (21.6, 62.6, and 211.1 MMBtu/hr respectively), and two boilers (416 MMBtu/hr each). In addition, eight new storage tanks will be constructed (in addition to existing tankage which will also be used in support of the new cracking unit), stormwater tanks, wastewater tanks, two natural gas liquid spheres, a flare, and a cooling tower. The permit also allows the applicant the choice of constructing two steam boilers with a backup generator, or a cogeneration unit (which consists of at least two turbines, each with its own duct burner, and a supplemental boiler). If the applicant chooses to proceed with the cogeneration project, the permit requires that the applicant supply additional engineering information, update the modeling submitted with the application, remain at or below the emissions estimated for the steam boilers and emergency generator, and obtain approval from the TNRCC before starting construction on the cogeneration portion of the ethylene cracking unit.

The emission increases associated with the construction of the ethylene cracking unit and associated facilities exceeded the significance levels for PSD and Nonattainment review. PSD review is applicable for NO_x, CO, PM_{10}, and SO_2. Nonattainment review is applicable for VOC. This permit was determined to be administratively complete as of December 31, 1997; therefore, NO_x increases associated with this permit meet the 182(f) exemption criteria for nonattainment review (although offsets are still required).

Emission increases resulting from this project total: 139.58 tons/year VOC, 1326.33 tons/year NO_x, 1625 tons/year CO, 76.49 tons/year SO_2, and 124.2 tons/year PM_{10}.

REQUEST FOR COMMENTS

REGION:	**10**	Reviewed by:	**Kathy Sauceda**
CITY:	**NA**	Reviewed by:	
COUNTY:	**NA**	Reviewed by:	
TARA:	**See Below**	Reviewed by:	
COMP:		Reviewed by:	**Tel Croston**
LEGAL:	**NA**	Reviewed by:	

REVIEW SUMMARY

PROCESS DESCRIPTION

The proposed ethylene cracking unit will be composed of nine ethylene cracking furnaces, three heaters, two boilers, eight new storage tanks (in addition to existing tankage utilized by this project), stormwater and wastewater tanks, two natural gas liquid spheres, a cooling tower, and a flare. Also involved in the construction is a Phillips Olefin Conversion Technology (POCT) Unit, and a condensate splitter. Fifty percent of the feed for the proposed ethylene crackers will be derived from the unit condensate splitter. The remaining 50 percent of the feed will be purchased natural gas liquids and/or offgas from the refiner's fluid catalytic cracker, de-ethanizer overheads from the saturate liquids unit, propane and butane.

The ethylene cracker consists of two sections: the pyrolysis section and the separation section. It is in the pyrolysis section that the feedstock is thermally cracked followed by the separation section where the specific products are separated. The ethylene cracker will produce chemical grade ethylene. Other products include, but are not limited to, propylene, butadiene, pyrolysis gasoline comprised of benzene, toluene, xylene, butenes, pentanes, and methane. Ethane will be recycled for additional cracking. After the cracking and separation process, some of the ethylene and butenes (along with other byproduct streams, like C4's) are routed to the POCT unit. The POCT converts the ethylene and 2-butene into propylene. This is achieved by two steps: selective hydrogenation of butadiene and the disproportionation reaction of ethylene and 2-butene. C4's from the ethylene cracking unit are routed to the hydrogenation unit (a two bed, fixed bed reactor system), where the butadienes and acetylenes are hydrogenated to 1-butene and 2-butene (raffinate can also be used as hydrogenation unit feed). The ethlyene and 2-butene are then reacted to form propylene. The ethylene and propylene will be collected and shipped off site via pipeline. Other byproducts will be routed to tankage for use in other parts of the Fina refinery.

The ethylene cracking furnaces will be periodically decoked by sparging air and steam through the inside of the furnace tubes. The particulate matter created during this process will be routed to a decoke cyclone. CO is also created during the decoking process. This is due to the need to control the temperature on the tube side of the furnace through the flow of excess air. The temperature control is necessary to prevent damage to the furnaces from overheating the tubes.

SOURCES. CONTROLS AND BACT

The proposed ethylene cracking unit will be composed of nine ethylene cracking furnaces, three heaters, two boilers, eight new storage tanks (in addition to existing tankage utilized by this project), storm water and wastewater tanks, two natural gas liquid spheres, a cooling tower, and a flare. Both PSD and nonattainment review are applicable for this proposed project. PSD review is applicable for NO_x, SO_2, CO, and PM_{10}. Nonattaimnent review for VOC is applicable (LAER review for VOC). This permit was determined to be administratively complete as of December 31, 1997; therefore, NO_x increases associated with this permit meet the 182(f) exemption criteria for nonattainment review (although offsets are still required). A summary of the various control technologies and the BACT analysis performed follows:

NO_x:

The nine ethylene cracking furnaces will be equipped with ultra low NO_x burners capable of obtaining a NO_x generation rate of 0.08 lb/MMBtu for the maximum short term (lb/hr) and an annual average NO_x generation rate of 0.05 lb/MMBtu of fuel gas fired. The burners are capable of obtaining a short term NO_x generation rate of 0.05 lb/MMBtu while burning natural gas; however, the vendor attributes the higher short term NO_x generation rate to the high temperatures at which the cracking furnaces operate (in excess of 2100 °F) combined with the potential of burning high hydrogen fuel for short periods of time (H_2 concentrations between 25 to 60 mole percent).

The heaters associated with the ethylene cracking unit will also be equipped with ultra low NO_x burners capable of obtaining a NO_x generation rate of 0.08 lb/MMBtu for the maximum short term and an annual average of 0.05 lb/MMBtu. In this case, the vendor attributed the higher short term NO_x generation rate to the high hydrogen concentration in the fuel.

The boilers are designed with partial flue gas recirculation (FGR) which is capable of meeting a NO_x generation rate of 0.06 lb/MMBtu for the maximum short term and an annual average NO_x generation rate of 0.05 lb/MMBtu.

The NO_x generation rate from the flare is based on the value of 0.0485 lb/MMBtu derived from the CMA/EPA flare studies.

CO:

The CO generation rate ranges from 0.077 lb/MMBtu for the ethylene cracking furnaces, 0.011 lb/MMBtu for the heaters, to 0.069 lb/MMBtu for the boilers. The CO generation rate is a function of good operating practice to minimize the NO_x emission rate from the various fired units, and is considered to be BACT. CO emissions are also created during the decoking process of the ethylene cracking furnaces.

This is due to the need to control the temperature on the tube side of the furnace through the flow

of excess air. The temperature control is necessary to prevent damage to the furnaces from overheating the tubes.

Control of CO from the decoking drum is technically impractical and economically unreasonable. In addition, the final design of the decoke system is not yet complete and the applicant is required, by permit condition, to supply updated emissions and design information prior to construction of those pieces of equipment.

The CO generation rate from the flare is based on the value of 0.3503 lb/MMBtu derived from the CMA/EPA flare studies.

SO_2 :

Short term SO_2 emission rates from all fired units are based on 40 CFR 60 (NSPS) Subpart J H_2S fuel gas concentrations of 160 ppmv, and is considered to be BACT for the types of fuel gas fired (including refinery fuel gas).

PM_{10} :

Short term and annual emission rates for PM_{10} are based on the vendor design data for the specific burners used in the various fired units. The PM_{10} generation rates vary from 0.005 lb/MMBtu for the ethylene cracking furnaces, 0.006 lb/MMBtu for the heaters, to 0.007 lb/MMBtu for the boilers. The use of natural gas and offgas (refinery fuel gas) is considered to be BACT. PM_{10} emissions will also be present from the decoking operation associated with the ethylene cracking furnaces. The final design of the decoke system is not yet complete and the applicant is required, by permit condition, to supply updated emissions and design information prior to construction of those pieces of equipment. In addition, PM_{10} emission rates were also estimated from the cooling tower. The applicant decided, based on the magnitude of the application, that they should address the possibility of PM_{10} from the ethylene cracking units cooling tower. The information was based on best available data provided from the manufacturer of the cooling tower.

Nonattainment Review and LAER:

The applicant performed a search of the Environmental Protection Agency's (EPA) RACT/BACT/LAER Clearinghouse to examine control technologies approved in the past to address VOC emissions from heaters/boilers, cooling towers, fugitive emissions, and storage tanks. The following controls are proposed as LAER for VOC:

Cracking furnaces, heaters, and boilers: The VOC emission rates from the fired units were obtained from the vendor and are based on the use of ultra low NO_x burners.

Fugitives: Fugitive emissions will be monitored with the 28 LAER fugitive monitoring and maintenance program. In addition to the 28 LAER requirements, the applicant will also monitor

connectors on a quarterly basis.

Tanks: The emissions from product and intermediate storage tanks will either be collected and routed to theflare system, or controlled through the use of floating roof technology. Floating roof tanks, both internal and external floating roof designs, will be equipped with liquid mounted primary seals and a rim mounted secondary seal. In addition, the applicant chose floating roof designs such that the fitting losses will be minimized.

Process and emergency relief valves: Process and emergency relief valves will be routed to the flare system.The flare will be designed to meet the requirements of NSPS 40 CFR 60.18.

Wastewater: All process wastewater from the ethylene cracking unit will be handled in an enclosed wastewater treatment system. The process wastewater system is completely segregated from the stonnwater gathering system. The wastewater will be steam stripped, and the collection drain tanks will be routed to the flare. Wastewater equalization will take place in a fixed roof tank (ie, no equalization ponds open to the atmosphere).

Cooling Tower: The VOC emissions from the cooling tower was estimated using the AP-42 controlled value of 0.7 lb/MM gallon flow. The cooling tower will be sampled initially using an air stripping method to establish the pounds per hour of VOC being emitted. The cooling tower will then be sampled on a monthly basis using an air stripping method or equivalent. The sample obtained will be collected in a Tedlar (R) bag (to help ensure sample integrity) and analyzed by gas chromatography. In addition, liquid samples will becollected for benzene (analyzed by gas chromatography) from each combined cooling water return. The exchangers associated with the cooling water loops of the ethylene cracking project will be of welded construction to minimize the potential of process leaks into the cooling water.

Considering the above described control technologies, BACT and LAER are met for their respective applicable compounds.

Monitoring and Testing: The applicant will install a continuous flow monitor and analyzer to provide a record of the vent stream flow and Btu content to the flare. The cracking furnaces, heaters, and auxiliary boilers willbe stack sampled for NO_x, CO, SO_2, and PM_{10}. In addition, a CEMs system will be used to measure and record instack concentrations of NO_x, CO, SO_2, and O_2 from each ethylene cracking furnace, the condensate splitterheater, and both boilers.

Offsets and Offset Trading:

This permit triggers nonattainment review for VOC and is 182(f) for NO_x. In each situation, offsets are required (although delayed until January 1, 2000 for NO_x per 182(f)) at the appropriate offset ratio for the specific nonattainment area.

Fina may choose to take advantage of offset trading as provided for in 30 TAC Section 101.29 (General Rules). Emission reduction provided as NO_x offsets for increases associated with the

ethylene cracker project shall total 1,182.8 tons/year if the offsets are purchased from within the Beaumont/PortArthur nonattainment area (offset ratio of 1.15: 1). If offset emissions are purchased from the Houston/Galveston nonattainment area, 1337.1 tons/year of offsets will be required (offset ratio of 1.30:1). The applicant shall identify whether the offsets are being purchased from the Beaumont/Port Arthur nonattainment area, the Houston/Galveston nonattaimnent area, or both (and the specific amount being purchased from each area).

VOC offsets have been provided to the total of 160.52 tons/year (ERC certificates 1075, 1076, and 1077).

IMPACTS EVALUATION

1. Was modeling done? **Yes** Type? **Full Dispersion**
2. Will GLC of any air contaminant cause violation of NAAQS? ..... **NO**
3. Is this a sensitive location with respect to nuisance? ..... **Moderate**
4. Is the site within 3000 feet of any school? ..... **NO**
5. Toxics/Modeling Evaluation:

Air dispersion modeling was performed according to the Texas Natural Resource Conservation commission (TNRCC)/EPA protocols. A significance analysis was initially conducted to determine if a full impact analysis would be required. The modeling results indicate that a full impact analysis to demonstrate compliance with the NAAQS and PSD Increment is required for NO_2, SO_2, and PM_{10}. The modeling results also indicated that a full impact analysis would not be required for CO. The following tables indicate the results of the air dispersion modeling performed for Fina's proposed project.

Table I - Significance Impact Analysis

Pollutant	Averaging Period	Maximum Modeled Concentration	Modeling Significance Level
NO_2	Annual	3.14 $\mu g/m^3$	1 µg/m3
CO	1 Hour	1,821.65 $\mu g/m^3$	2,000 $\mu g/m^3$
	8 Hour	298.87 $\mu g/m^3$	500 $\mu g/m^3$
PM_{10}	24 Hour	8.97 $\mu g/m^3$	5 $\mu g/m^3$
	Annual	0.40 $\mu g/m^3$	1 $\mu g/m^3$
SO_2	3 Hour	68.8 $\mu g/m^3$	25 $\mu g/m^3$
	24 Hour	3.89 $\mu g/m^3$	5 $\mu g/m^3$
	Annual	0.25 $\mu g/m^3$	1 $\mu g/m^3$

Table 2 - Full Impact Analysis - NAAQS

Pollutant	Averaging Period	Maximum Modeled NO_2 Plus	NAAQS

		Background	
NO_2	Annual	95 $\mu g/m^3$	100 $\mu g/m^3$
PM_{10}	24 Hour	141.41 $\mu g/m^3$	150 $\mu g/m^3$
SO_2	3 Hour	1039 $\mu g/m^3$	1300 $\mu g/m^3$

Table 3 - PSD Increment Analysis

Pollutant	Averaging Period	Maximum Modeled NO_2 Concentration	PSD Increment
NO_2	Annual	14 $\mu g/m^3$	25 $\mu g/m^3$
PM_{10}	24 Hour	17.08 $\mu g/m^3$	30 $\mu g/m^3$
SO_2	3 Hour	476.5 $\mu g/m^3$	512 $\mu g/m^3$

The modeling analysis shows that there are no NAAQS violations resulting from the emissions associated with this project, and that the increment is not exceeded.

In addition, full dispersion modeling was also conducted for benzene, toluene, ethylbenzene, xylene, styrene, 1,3-butadiene, ethylene, propylene, and C9+. The above compounds were modeled as a representative, worst case group of VOC's emitted by the applicants proposed ethylene cracker unit and associated facilities. The modeled results were compared against 10% of the ESL for the respective compounds. All compounds modeled were less than 10% of their respective ESLs (meeting the requirements of Step 9A in the NSR/TARA Modeling and Effects Review Applicability guidance document). The applicant also modeled benzene increases since July 12, 1993 for comparison against 25% of the ESL. Short term and annual emissions were evaluated, and modeling results indicate that both values will be less than 25% of the applicable ESLs (Step 9B in the NSR/TARA Modeling and Effects Review Applicability guidance document). The ratio test (Step 10) was performed for toluene, xylene, ethylbenzene, styrene, 1,3-butadiene, ethylene, and propylene. All ratios were found to be acceptable (GLC/ESL was less than or equal to En/Et). In addition, C9+ is a unique category to the applicants Port Arthur refining complex. Modeling of new emissions was determined to be equivalent to plant wide modeling for this compound mix.

All compounds evaluated meet the requirements of the NSR/TARA Modeling and Effects Review Applicability guidance document, and no further analysis was determined to be necessary. The modeling submitted in support of this application (for both NAAQS and air toxic runs) was audited and accepted by TNRCC NSRP modeling staff.

COMPLIANCE HISTORY

1. Was a NOV issued for construction without a permit? ..... **NO**
2. Was the NOV resolved by issuance of permit? ..... **NA**

Comments:

MACT COMPLIANCE

1. Compliance with applicable MACT standards expected? ..... **NA**

Subparts and

MISCELLANEOUS

1. Is applicant in agreement with special conditions? ..... **YES**

Company representative(s)? ..... **Jannetta Bowden**

Contacted via? ..... **Phone**

Date of contact? ..... **9\2\98**

2. Did the franchise tax verify the applicant to be in good standing? ..... **YES**
3. Emissions reductions resulting from the application of BACT required by state rules, avoidance of potential impacts problems, and voluntary reductions .....
4. Other permit(s) affected by this action? **-YES** x **NO**

If YES, list permit number(s) and actions required or taken

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Permit Engineer Date Team Leader/Section Manager/Backup Date

NEW PERMIT/AMENDMENT/CLOC SOURCE ANALYSIS REVIEW

Permit No: **36644, PSD-TX-903, N-007** Company: **Fina Oil & Chemical Company**

Project Type: **CRVW** Facility Name: **ETHYLENE CRACKER & ASSOCIATED FACILITIES**

Record No: **54153** City: **Port Arthur**

Account No: **JE-0005-H** County: **Jefferson**

113.310 Compliance with applicable MACT standards expected? ..... **NA**
Subparts and

116.111(2)(A)(i) Are the emissions expected to comply with all TNRCC air quality rules and regulations and the intent ofthe Texas Clean Air Act? ..... **Yes**

116.111(2)(B) Will emissions be measured? ..... **Yes**
Method: **Stack Testing, CEM systems, Air stripping methods and liquid samples (cooling tower), and flow/Btu content monitoring (flare).**
Comments:

116.111(2)(C) Will the facility utilize BACT? ..... **Yes**
116.111(2)(D) Compliance with applicable NSPS expected?..... **Yes**
Subparts **A & Db, Kb, VV, NNN, and RRR (and YYY when promulgated)**
116.111(2)(F) Compliance with applicable NESHAPS expected? ..... **Yes**
Subparts **A & J, V, and FF**
116.111(2)(G) Is the facility expected to perform as represented in the application? **Yes**
116.111(2)(H) Is nonattainment review required? ..... **Yes**
A. Is the facility located in a nonattainment area? ..... **Yes**
If no, skip to 116.111(2)(1). If yes, continue.
B. Federal major source for nonattainment pollutant? ..... **Yes**
C. Federal major modification for nonattainment pollutant? ..... **Yes**
1 . Did project emission increases (proposed allowables minus the two-year average actualemissions, no consideration given to decreases) for the nonattainment pollutant trigger netting? ..... **Yes**
If yes, attach Table IN & 9N. If no, explain:
2. Is the contemporaneous increase of nonattainment pollutant significant? ..... **Yes**
If yes, nonattainment review is required.

116.111(2)(I) Is PSD applicable? ..... **Yes**
A. Is facility a federal major source (100/250tons/yr)? ..... **Yes**
B. Is the project a federal major modification? ..... **Yes**
1. Did project emission increases (proposed allowables minus the two-year average actual emissions, no consideration given to decreases) trigger netting? ..... **Yes**
2. Was contemporaneous increase significant? ..... **Yes**
3. Change excluded by 40 CFR 52.21(b)(2)(iii)? ..... **No**
If yes to B.2 or B.3 above, explain: The contemporaneous increase for VOC, as determined by netting, was above the significance level.

116.130-137 Was public notification required? ..... **Yes**
If no, give reason:
A. Date application received: **9\24\97** Date application complete: **7/2/98**
B. Preliminary determination .....
C. Public notice mailed **7/10/98**

D. Pollutants: **nitrogen oxides, carbon monoxide, sulfur dioxide, particulate matter, and volatile organic hydrocarbons including but not limited to: ethylene, propylene, benzene, toluene, ethyl benzene, xylene, styrene, 1,3-butadiene, and C9+. In addition increment consumed was also published for sulfur dioxide, particulate matter, and nitrogen dioxide**.

E. Published: **7/17 and 7/18 in the Beaumone Enterprise, and also published 7/21 and 7/22 in the Port Arthur News**

F. Bilingual public notification required? ..... **NO**
Language:
Published: & in
G. No. of public comments? ... **None** Technical Issues? .....
Meeting requested? ... **None Requested** Meeting held? .....
Hearing requested? ... **None Requested** Hearing held? ..... I .....
Comments:
H. Certification of sign posting according to 116.133 ? ..... **Yes**
I . Final action: NA Letters enclosed? .....
116.140 Permit Fee: **$ 75,000** Fee certification provided? ..... **NA**
122.10(8)(A) Is facility a major source under FCAA Section 112(b)? .... **Yes**
A. Facility emits 10 tons or more of any single HAP? ..... **NO**
B. Facility emits 25 tons or more of a combination ..... **NO**
C. Facility emits 100 tons or more of any air pollutant ..... **Yes**

122.10(8)(c) Is facility a named source under FCAA Section 112? .. **Yes**
Note: Fugitive emissions are not included in total emissions unless the facility is named in 30 TAC 122.10(8)(C).

Miscell: 1. Franchise tax verified and in good standing?..... **Yes**
2. Is any other permit affected by this action? **-YES** X **NO**
If YES, give permit numbers
Comments:

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Permit Engineer Date Team Leader/Section Manager/Backup Date

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

Permit Nos. 36644, PSD-TX-903, and N-007

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

		AIR CONTAMINANTS DATA		
Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates * lb/hr	TPY
N-1	Recycle Ethane Cracking Furnace	NO_x	27.40	94.52
		SO_2	1.19	5.21
		CO	26.37	115.22
		PM_{10}	1.71	7.50
		VOC	0.65	2.85
N-2	Fresh Feed Cracking Heater	NO_x	35.63	122.91
		SO_2	1.55	6.77
		CO	34.30	150.22
		PM_{10}	2.23	9.75
		VOC	0.85	3.71
N-3	Fresh Feed Cracking Heater	NO_x	35.63	122.91
		SO_2	1.55	6.77
		CO	34.30	150.22
		PM_{10}	2.23	9.75
		VOC	0.85	3.71
N-4	Fresh Feed Cracking Heater	NO_x	35.63	122.91
		SO_2	1.55	6.77
		CO	34.30	150.22
		PM_{10}	2.23	9.75
		VOC	0.85	3.71
N-5	Fresh Feed Cracking Heater	NO_x	35.63	122.91
		SO_2	1.55	6.77
		CO	34.30	150.22
		PM_{10}	2.23	9.75
		VOC	0.85	3.71

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

AIR CONTAMINANTS DATA

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates * lb/hr	TPY
N-6	Fresh Feed Cracking Heater	NO_x	35.63	122.91
		SO_2	1.55	6.77
		CO	34.30	150.22
		PM_{10}	2.23	9.75
		VOC	0.85	3.71
N-7	Fresh Feed Cracking Heater	NO_x	35.63	122.91
		SO_2	1.55	6.77
		CO	34.30	150.22
		PM_{10}	2.23	9.75
		VOC	0.85	3.71
N-8	Fresh Feed Cracking Heater	NO_x	35.63	122.91
		SO_2	1.55	6.77
		CO	34.30	150.22
		PM_{10}	2.23	9.75
		VOC	0.85	3.71
N-9	Fresh Feed Cracking Heater	NO_x	35.63	122.91
		SO_2	1.55	6.77
		CO	34.30	150.22
		PM_{10}	2.23	9.75
		VOC	0.85	3.71
N-10	Catalyst Regeneration Effluent	VOC	<0.001	<0.001
N-11	Reactor Regeneration Effluent	VOC	<0.001	<0.001
N-12	DP Reactor Feed Heater	NO_x	5.01	13.71
		SO_2	0.22	0.95
		CO	0.69	3.02
		PM_{10}	0.38	1.64
		VOC	0.17	0.74
N-13	DP Reactor Regeneration Heater			

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

AIR CONTAMINANTS DATA

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates * lb/hr	TPY
		NO_x	1.73	1.42
		SO_2	0.07	0.10
		CO	0.24	0.31
		PM_{10}	0.13	0.17
		VOC	0.06	0.08
N-14A	Auxillary Boiler	NO_x	24.96	91.10
		SO_2	1.44	6.32
		CO	28.70	125.72
		PM_{10}	2.91	12.75
		VOC	2.91	12.75
N-14B	Auxillary Boiler	NO_x	24.96	91.10
		SO_2	1.44	6.32
		CO	28.70	125.72
		PM_{10}	2.91	12.75
		VOC	2.91	12.75
N-15	Flare	VOC	4.61	6.45
		NO_x	0.49	2.12
		CO	3.50	15.34
		SO_2	0.01	0.03
N-16	Emergency Generator	NO_x	36.68	2.86
		SO_2	2.43	0.19
		CO	7.90	0.62
		PM_{10}	2.60	0.20
		VOC	2.97	0.23
N-17	Condensate Splitter Heater	NO_x	16.89	46.22
		SO_2	0.73	3.21
		CO	2.32	10.17
		PM_{10}	1.27	5.55
		VOC	0.57	2.50
N-18	Decoking Drum	CO	720.00	27.88

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

AIR CONTAMINANTS DATA

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates * lb/hr	TPY
		PM_{10}	78.73	3.04
TK-2501	IFR Spent Caustic	VOC	0.29	1.16
TK-8001	IFR WW Equalization	VOC	0.39	1.72
TK-8101	EFR Contaminated Stormwater	VOC	<0.001	<0.001
TK-8010	EFR Contaminated Stormwater	VOC	<0.001	<0.001
TK-7702	Sulfuric Acid Tank	H_2SO_4	<0.001	<0.001
		SO_3	<0.001	<0.001
D-7703	IFR Wash Oil Day Tank	VOC	0.04	0.05
D-7705	IFR Tank	VOC	0.09	0.06
TK-3005	IFR Tank	VOC	0.68	1.58
TK-3002	EFR Tank	VOC	0.33	0.90
TK-3003	EFR Tank	VOC	0.33	0.90
TK-3004	EFR Tank	VOC	0.43	0.46
TK-3006	IFR Tank	VOC	0.26	0.56
TK-3007	IFR Tank	VOC	0.57	2.37
TK-3000	IFR Tank	VOC	0.92	3.68
TK-3001	IFR Tank	VOC	0.92	3.68
F-1	Fugitives (4)	VOC	2.44	10.77
F-2	Cooling Tower	VOC (5)	10.08	44.15
		Benzene	0.45	1.99

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

AIR CONTAMINANTS DATA

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates * lb/hr	TPY
		PM_{10}	2.50	2.59
TBN (6)	Cogen	NO_x	86.6	185.06
		SO_2	5.31	12.83
		CO	65.3	252.06
		PM_{10}	8.42	25.7
		VOC	8.79	25.73

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in General Rule 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM_{10} - particulate matter (PM) equal to or less than 10 microns in diameter. Where PM is not listed, it shall be assumed that no particulate matter greater than 10 microns is emitted.
CO - carbon monoxide
H_2SO_4 - sulfuric acid
SO_3 - sulfur trioxide
(4) Fugitive emissions are an estimate only and should not be considered as a maximum allowable emission rate.
(5) The VOC emissions rates from the cooling tower are 10.08 pounds per hour and 44.15 tons per year, including benzene. The VOC emission rates are for total VOC.
(6) Place holder for cogeneration unit emissions. The cogeneration unit includes two turbines equipped with duct burners, and a supplemental boiler. The holder of this permit may choose the Auxiliary Boilers and Emergency Generator (EPN's N-14A, N-14B, and N-16, respectively) or a cogeneration unit and supplemental boiler. The applicant may supply additional information, EPN's for each specific piece of equipment, etc., as required by Special Condition No. 26 of this permit.

* Emission rates are based on and the facilities are limited by the following maximum operating schedule:

_____Hrs/day _____Days/week _____Weeks/year or 8,760 Hrs/year

Dated

SPECIAL CONDITIONS

Permit Nos. 36644, PSD-TX-903, and N-007

1. The total emissions of air contaminants from any of the sources shall not exceed the values stated on the attached table entitled "Emission Sources - Maximum Allowable Emission Rates." **(PSD, N)**

FEDERAL APPLICABILITY

2. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) Regulations on Standards of Performance for New Stationary Sources promulgated for: **(9/00)**

   A. General Provisions, Subpart A.

   B. Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemical Manufacturing Industry (SOCMI) in Title 40 Code of Federal Regulations Part 60 (40 CFR 60), Subpart VV.

   C. The VOC Emissions from SOCMI Distillation Operations in 40 CFR 60, Subpart NNN.

   D. Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) in 40 CFR 60, Subpart Kb.

   E. The VOC Emissions from SOCMI Reactor Processes, in 40 CFR 60, Subpart RRR.

   F. Industrial-Commercial-Institutional Steam Generating Units in 40 CFR 60, Subpart Db.

   G. Stationary Gas Turbines in 40 CFR 60, Subpart GG.

   H. Petroleum Refineries in 40 CFR 60, Subpart J.

   I. VOC Emissions from Petroleum Refinery Wastewater Systems in 40 CFR 60, Subpart QQQ.

3. These facilities shall comply with all applicable requirements of EPA Regulations on Standards of Performance for New Stationary Sources upon promulgation for the Standards of Performance for VOC Emissions from SOCMI Wastewater, 40 CFR 60, Subparts A and YYY.

4. These facilities shall comply with all applicable requirements of EPA Regulations on National Emission Standards for Hazardous Air Pollutants (NESHAPS) Parts 61 and 63 promulgated for: **(9/00)**
   A. Benzene Waste Operations in 40 CFR 61, Subparts A and FF.

B. Equipment Leaks (Fugitive Emission Sources) of Benzene in 40 CFR 61, Subparts A and J.

C. Equipment Leaks (Fugitive Emission Sources) in 40 CFR 61, Subparts A and V.

D. Petroleum Refineries in 40 CFR 63, Subparts A and CC.

E. Synthetic Organic Manufacturing Industry in 40 CFR 63, Subparts A and F.

F. Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater in 40 CFR 63, Subparts A and G.

G. Equipment Leaks in 40 CFR 63, Subparts A and H.

5. If any condition of this permit is more stringent than the regulations so incorporated, then for purposes of complying with this permit, the permit conditions will govern and be the standard by which compliance is demonstrated.

EMISSION STANDARDS AND OPERATING SPECIFICATIONS

6. Production rates for the equipment covered by this permit shall not exceed the values listed in the Confidential File, Table 2a, dated September 24, 1997. The maximum ethylene production rate shall not exceed 2.2 billion pounds a year (based on a 12-month rolling average). Monthly records of the annual ethylene production shall be maintained on-site for a period of two years and made available to representatives of the Texas Natural Resource Conservation Commission (TNRCC) upon request. **(PSD, N)**

7. Storage and Loading of VOC

A. The control requirements specified in paragraphs B through E of this condition shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.5 psia at the maximum expected operating temperature or (2) to storage tanks smaller than 25,000 gallons.

B. An internal floating deck or “roof” or equivalent control shall be installed in all tanks.

The floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal. Installation of equivalent control requires prior review and approval by the TNRCC Executive Director.

C. An open-top tank containing a floating roof (external floating roof tank) which uses double seal or secondary seal technology shall be an approved control alternative to an internal floating roof tank provided the primary seal consists of either a mechanical shoe seal or a liquid-mounted seal, and the secondary seal is rim-mounted. A weathershield is not approvable as a secondary seal unless specifically reviewed and determined to be vapor-tight.

D. For any tank equipped with a floating roof, the holder of this permit shall follow 40 CFR 60.113b, Testing and Procedures, to verify seal integrity. Additionally, the permit holder shall follow 40 CFR 60.115b, Reporting and Recordkeeping Requirements, to provide records of the dates seals were inspected, seal integrity, and corrective actions taken.

E. The floating roof design shall incorporate sufficient flotation to conform to the requirements of American Petroleum Institute (API) Code 650, or an equivalent degree of flotation, except that an internal floating cover need not be designed to meet rainfall support requirements and the materials of construction may be steel or other materials.

F. Uninsulated tank exterior surfaces exposed to the sun shall be white or aluminum.

G. For purposes of assuring compliance with VOC emission limitations, the holder of this permit shall maintain a monthly emissions record which describes calculated emissions of VOC from all storage tanks and loading operations. The record shall include tank or loading point identification number, control method used, tank or vessel capacity in gallons, name of the material stored or loaded, VOC molecular weight, VOC monthly average temperature in degrees Fahrenheit, VOC vapor pressure at the monthly average material temperature in psia, and VOC throughput for the previous month and year-to-date. Records of VOC monthly average temperature are not required to be kept for unheated tanks which receive liquids that are at or below ambient temperatures. These records shall be maintained at the plant site for at least two years and be made available to representatives of the TNRCC upon request.

H. If throughput records are specified in the special conditions of this permit, the holder of this permit may keep such records in lieu of the records required in paragraph G.

I. Emissions for tanks and loading operations shall be calculated using: (a) AP-42 "Compilation of Air Pollution Emission Factors, Chapter 12 - Storage of Organic Liquids" and (b) the TNRCC publication titled "Technical Guidance Package for Chemical Sources - Storage Tanks."

J. Operation without visible liquid leaks or spills shall be maintained at all loading and unloading facilities, regardless of vapor pressure. This does not apply to momentary dripping associated with the initial connection or disconnection of fittings. Sustained dripping from fittings during loading and unloading operations is not permitted. Any liquid spill that occurs during loading and unloading activities shall be reported pursuant to 30 Texas Administrative Code (TAC) Sections 101.6 or 101.7 and shall be cleaned up immediately to minimize air emissions. **(N)**

8. The fittings associated with all floating roof storage tanks shall follow the representations made in the permit application. The internal floating roof benzene storage tanks (Tanks 808, 809, and 810) shall be equipped with a mechanical shoe primary seal, and the emissions from these tanks shall be routed to the Vapor Combustor (Emission Point No. [EPN] 22 BZNTKFLR). **(N, 9/00)**

9. External Floating Roof Tanks 800, 801, 802, and 805 shall be equipped with seals capable of meeting the tight fitting seal factor requirements of the API Manual of Petroleum Measurement Standards, Chapter 19 (First Edition, April 1997). The primary and secondary seals shall be inspected for gaps two times per year to ensure a seal gap of 1/8 inch or less. The applicant shall conduct the gap measurements when the tank roof is:

   A. On its legs at the time of the initial fill.

   B. When the tank is at or near its maximum expected fill level.

   During the initial hydrotest for each tank, seal gap measurements shall be conducted when the tank is on its legs, halfway full, and at the maximum level of fill.

   Records of the seal gap inspections shall be maintained on-site for a period of two years and made available to representatives of the TNRCC upon request. **(N, 3/99)**

10. <u>Piping, Valves, Connectors, Pumps, Agitators, and Compressors in VOC Service - Intensive Directed Maintenance - 28 LAER</u>

A. With the exception of paragraph N, these conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. In addition, all connectors shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. Non-accessible valves shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no

later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in 40 CFR 60.485(a)-(b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system.

Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump, compressor, and agitator seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, agitator seals, compressor seals, and pump seals found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. The TNRCC Executive Director, at his discretion, may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown.

I. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TNRCC Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, and corrective actions taken. Records of weekly physical (visual) inspections are not required unless a leak is detected.

J. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable NESHAPS and does not constitute approval of alternative standards for these regulations.

K. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

L. The percent of valves leaking used in paragraph K shall be determined using the following formula:

$(Vl + Vs) \times 100/Vt = Vp$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

M. Alternative connector monitoring frequency schedules (“skip options”) of 40 CFR 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the annual connector instrument monitoring required by paragraph E of this permit condition.

N. Any component found to be leaking by physical inspection (i.e., sight, sound, or smell)

shall be repaired or monitored with an approved gas analyzer within 15 days to determine whether the component is leaking in excess of 500 ppmv of VOC. If the component is found to be leaking in excess of 500 ppmv of VOC, it shall be subject to the repair and replacement requirements contained in this special condition. **(N)**

11. A. In addition to the weekly physical inspection required by Item E of Special Condition No. 10, all accessible connectors in gas/vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F through J of Special Condition No. 10.

B. In lieu of the monitoring frequency specified in paragraph A, connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

C. The percent of connectors leaking used in paragraph B shall be determined using the following formula:

$(Cl + Cs) \times 100/Ct = Cp$

Where:

Cl = the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Cs = the number of connectors for which repair has been delayed and are listed on the facility shutdown log.

Ct = the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor connectors.

Cp = the percentage of leaking connectors for the monitoring period. **(N)**

12. <u>Carbon Compound Waste Gas Streams</u>

Except as may be provided for in the special conditions of this permit, all waste gas from point sources containing VOC and/or other organic compounds (hydrocarbons and/or hydrocarbon derivatives excluding carbon dioxide) shall be routed to either the Flare (EPN N-15) or Thermal Oxidizer (EPN N-19). The Flare (EPN N-15) shall operate with no less than 99 percent efficiency in disposing of ethylene and propylene, and 98 percent efficiency in disposing of the carbon compounds captured by the collection system. The waste gas streams shall include process vents, relief valves, analyzer vents, steam jet exhausts, upset emissions, start-up and shutdown-related emissions or purges, blowdowns, or other system emissions of waste gas. The Thermal Oxidizer (EPN N-19) shall operate with no less than 99.99 percent efficiency in disposing of VOC and or other organic compounds. Storage tank vents, cooling tower exhaust, and process fugitive emissions are excluded from this requirement. Any other exception to this condition requires prior review and approval by the TNRCC Executive Director, and such exceptions may be subject to strict monitoring requirements.

In addition, the Vapor Combustor (EPN 22BTNTKFLR) handling the vapor streams from the benzene storage tanks shall be designed to operate with a 98 percent destruction efficiency, and shall meet the heating value requirements outlined in 40 CFR 60.18. **(PSD, N, 9/00)**

13. Emissions from the following Vessels shall be routed to the Flare: D-8001, D-7702, D7703, D-7705, FA-2501A, FA-2501B, D-8002, D-8003, D-8601, D-8602, D-8604, and D-8007. The following vessels shall be routed to either the flare or thermal oxidizer: X-8002 and X-8003. **(PSD, N, 9/00)**

14. The ground flare shall be designed and operated in accordance with the following requirements:

    A. The gas combusted at the flare tips shall have a minimum net heating value of at least 900 British thermal units per standard cubic feet (Btu/scf) under all flow conditions. This shall be ensured by the addition of assist natural gas to the flare tips to maintain the minimum net heating value.

B. The flare shall be operated with a flame present at all times and have a constant pilot flame. The flame shall be monitored by thermocouple or an equivalent IR scanner. The pilot fuel supply shall be equipped with a flow indicator, such as a gas rotameter, which will provide visual confirmation of pilot fuel gas flow. Any interruption in pilot gas flow will require immediate corrective action. Those components of the automatic reignition system which require periodic replacement shall be replaced as needed, but in no case shall they remain in service longer than recommended by the manufacturer. In addition, cameras shall maintain a 24-hour surveillance of the flare system for smokeless operation.

C. The flare shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. **(PSD, N, 4/99)**

15. The holder of this permit shall install a continuous flow monitor and an analyzer that provide a record of the vent stream flow and Btu content to the ground flare. The flow monitor sensor and analyzer sample points should be installed in the vent stream as near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. The average hourly values of the flow and composition shall be recorded. Records of the hourly averages shall be maintained for two years and be made available to representatives of the TNRCC upon request. **(PSD, N)**

16. Cogeneration Train Unit 1 (CTG/HRSG Unit 1), EPN N-20A, shall be comprised of a General Electric Frame 6B turbine and a 310.4 million Btu per hour (MMBtu/hr), based on the higher heating value (HHV) of fuel, duct burner. Cogeneration Train Unit 2 (CTG/HRSG Unit 2), EPN N-20B, shall be comprised of a General Electric Frame 6B Turbine, a 310.4 MMBtu/hr duct burner and selective catalytic reduction (SCR). Concentrations shall be represented in parts per million by volume on a dry basis (ppmvd) when corrected to 15 percent oxygen (O_2), without correction to International Standards Organization conditions, at any load except during periods of start-up or shutdown

A. Combined emissions from the gas turbine plus duct burner shall not exceed 15 ppmvd nitrogen oxides (NO_x) or 50 ppmvd carbon monoxide (CO) for CTG/HRSG Unit 1 and 9 ppmvd NO_x or 50 ppmvd CO for CTG/HRSG Unit 2 when corrected to 15 percent O_2.

B. The concentration of ammonia (NH_3) in the exhaust gases of CTG/HRSG Unit 2 shall not exceed 7 ppmvd when corrected to 15 percent O_2. **(PSD, N, 4/99)**

17. The permit holder shall maintain a quantity of no more than 1,700 gallons of anhydrous NH_3 on-site per cogeneration train at any time. Additionally, the permit holder shall maintain prevention and protection measures for the NH_3 storage system as represented in the permit application which includes (but is not limited to) the following:

    A. The NH_3 storage tank area will be marked and secured so as to protect the NH_3 storage tank from accidents that could cause a rupture.

    B. A water deluge system shall be installed to cover the tank and loading area to mitigate any airborne releases of NH_3.

    C. In the event of a release of the NH_3 from the liquid fill line, pressure vessel due to over pressurization, process line to the SCR system, or the vapor return lines from the vaporizer, or any other accidental release of NH_3, the permit holder shall follow the mitigation procedures set out in the permit application and follow the contingency plan that will be complete before start-up of the SCR.

    D. The following audio, visual, and olfactory inspection of piping, valves, pumps, and compressors in NH_3 service shall be followed:

        (1) Audio, olfactory, and visual checks for NH_3 leaks within the operating area shall be made every 12 hours.

        (2) Immediately, but no later than one hour upon detection of a leak, plant personnel shall take the following actions:

            (a) Isolate the leak.
            (b) Commence repair or replacement of the leaking component.
            (c) Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

    Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TNRCC upon request. **(4/99)**

18. The thermal oxidizer shall be designed to operate with a 99.99 percent destruction efficiency. The firebox temperature shall be continuously monitored and recorded, and shall not be less than 1800 °F. **(PSD, N, 3/99)**
19. Cracking furnaces, boilers, and heaters associated with the Ethylene Cracker Project shall not

exceed the firing rates (HHV) and burner technology as listed below:

EPN	Capacity (MMBtu)	Contaminant	Heat Specific Factor (lb/MMBtu)
N-1 (H-0100)	302.0	NO_x	0.06 (annual) 0.08 (hourly)
		CO	0.077
N-2 (H-0200)	441.7	NO_x	0.06 (annual) 0.08 (hourly)
		CO	0.077
N-3 (H-0300)	441.7	NO_x	0.06 (annual) 0.08 (hourly)
		CO	0.077
N-4 (H-0400)	441.7	NO_x	0.06 (annual) 0.08 (hourly)
		CO	0.077
N-5 (H-0500)	441.7	NO_x	0.06 (annual) 0.08 (hourly)
		CO	0.077
N-6 (H-0600)	441.7	NO_x	0.06 (annual) 0.08 (hourly)
		CO	0.077
N-7 (H-0700)	441.7	NO_x	0.06 (annual) 0.08 (hourly)
		CO	0.077
N-8 (H-0800)	441.7	NO_x	0.06 (annual) 0.08 (hourly)
		CO	0.077

EPN	Capacity (MMBtu)	Contaminant	Heat Specific Factor (lb/MMBtu)

N-9 (H-0900)	441.7	NO_x	0.06 (annual) 0.08 (hourly)
		CO	0.077
N-12 (H-6101)	62.58	NO_x	0.05 (annual) 0.08 (hourly)
		CO	0.011
N-13 (H-6102)	21.56	NO_x	0.05 (annual) 0.08 (hourly)
		CO	0.011
N-14 (B-7240)	227.5	NO_x	0.06 (annual) 0.06 (hourly)
		CO	0.069
N-17 (40 H-1)	211.07	NO_x	0.05 (annual) 0.08 (hourly)
		CO	0.011

The fuel flow and heating value (Btu/scf, upper heating value basis) of the fuel firing each cracking furnace, boiler, and heater shall be continuously monitored and recorded. A rolling 12-month annual average and the one-hour maximum firing rates shall be updated daily to demonstrate compliance with the firing rates shown. Records of the annual average and one-hour maximum firing rates shall be maintained at the plant site for a period of two years and made available to representatives of the TNRCC upon request. **(PSD, N, 4/99)**

20. Total operating hours devoted to decoking the cracking furnaces shall not exceed 3,024 (63 decoking operations/year total) per year. The holder of this permit shall maintain monthly records of the operating hours devoted to decoking. These records shall be maintained on-site for a period of two years and made available to representatives of the TNRCC upon request.

The requirements of Special Condition No. 19 (pound NO_x/MMBtu) are not applicable when the cracking furnace is in its decoking cycle; however, the NO_x mass emission rates specified in the maximum allowable emission rates table (MAERT) shall not be exceeded when the cracking furnace is in its decoking cycle. **(PSD)**

21. Opacity of emissions from the cracking furnaces, boilers, heaters, cogeneration trains, and decoke drum must not exceed 5 percent averaged over a six-minute period, except for those periods described in 30 TAC Section 111.111(a)(1)(E). **(4/99)**

22. All process wastewater from the ethylene cracking unit shall be handled in an enclosed treatment system. Process wastewater shall be completely segregated from the storm water gathering system. Process wastewater shall be steam stripped, with the stripper overheads routed back into the process. Vapors from all process wastewater collection drain tanks shall be routed to the flare. Vapors from the benzene extraction unit, spent caustic oxidizer vent, and the CPI/IGF vent shall be routed to the thermal oxidizer. **(N, 3/99)**

23. The holder of this permit shall perform sampling of the cooling tower using an air stripping device and other testing as necessary to establish the pounds per hour (lb/hr) of VOC being emitted into the atmosphere from the cooling tower associated with this permit. All sampling and testing methods shall be subject to approval of the TNRCC Executive Director prior to their implementation. The sample shall be collected in a sample bag (Tedlar® bag) and analyzed by gas chromatography within 24 hours of sample collection. The minimum detection level of the testing system shall be equivalent to no more than five tons per year (TPY) of VOC emissions, which for this facility is approximately 0.4 ppmv (air-stripped concentration, as ethylene) or approximately 0.015 ppmw concentration in water. The VOC concentration (ppmv) in the exhaust from the air stripping testing system or equivalent testing system and the corresponding pounds of strippable VOC per gallon of cooling water should be reported. These will be used to determine the level (either ppmv or lb/VOC/gal) at which a leak into cooling water will be assumed in the ongoing monitoring program. The MAERT shall be amended or altered to reflect the baseline emission rate determined by this special condition. Within 45 days after completion of sampling, copies of the test report shall be submitted to the TNRCC Office of Permitting, Remediation, and Registration, Air Permits Division and the TNRCC Regional Office. **(N)**

24. The holder of this permit shall perform sampling and other testing as necessary to demonstrate ongoing compliance with the emission limits for the cooling tower. The VOC associated with cooling tower water shall be monitored monthly with an approved air stripping system or equivalent. The sample obtained from the air stripping system shall be collected in a Tedlar® bag and analyzed by gas chromatography. The minimum detection level of the testing

system shall be equivalent to no more than five TPY of VOC emissions, which for this facility is approximately 0.4 ppmv (air-stripped concentration, as ethylene) or approximately 0.015 ppmw (as ethylene) concentration in water. The appropriate equipment shall be maintained so as to minimize fugitive VOC emissions from the cooling tower. The results of the monitoring and maintenance efforts shall be recorded, and such records shall be maintained for a period of two years. The records shall be made available to the TNRCC Executive Director upon request.

If a leak equivalent to more than five TPY of VOC emissions above baseline is detected, the owner or operator shall comply with the requirements in Special Condition No. 24A except as provided in Special Condition No. 24B through E.

Documentation of a decision to delay repair shall state the reasons repair was delayed and shall specify a schedule for completing the repair as soon as practical. For the purposes of this permit condition, delay of repair means exceeding the time frame established in Special Condition No. 24A. Prior to exceeding the time frame established in Special Condition No. 24A, all documentation of a decision to delay repair shall be submitted to the TNRCC Beaumont Regional Office for approval.

A. The leak shall be repaired as soon as practical but not later than 45 calendar days after the owner or operator receives results of monitoring tests indicating a leak. The leak shall be repaired unless the owner or operator demonstrates that the results are due to a condition other than a leak.

B. Delay of repair of heat exchange systems for which leaks have been detected is allowed if the equipment is isolated from the process.

C. Delay of repair is also allowed if repair is technically infeasible without a shutdown and a shutdown is expected within the next two months.

D. Delay of repair is also allowed for up to 120 calendar days if necessary parts or personnel were not available.

E. Delay of repair is also allowed if repair is technically infeasible without a shutdown and the shutdown would cause greater emissions than the potential emissions from delaying repair. The owner or operator may delay repair until the next shutdown of the process equipment associated with the leaking heat exchanger. The owner or operator shall document the basis for the determination that a shutdown for repair would cause greater emissions than the emissions likely to result from delaying repair. If the delay will exceed

two years, and the projected emissions due to this leak will exceed the rates as listed on the MAERT for this source, then the owner or operator shall amend or alter the MAERT to reflect the increase in VOC emissions and following the repair, the owner or operator shall determine a new baseline of VOC emissions and amend or alter the MAERT to reflect the decrease in VOC emissions. **(N)**

25. The holder of this permit shall conduct daily liquid samples (analyzed by gas chromatography) on each of the four Cooling Water Returns (A, B, C, and D returns) for benzene at 0.013 ppmw (or 13.0 ppb) detection limit. In addition, sampling for benzene using a mass spectrophotometer shall be conducted every month. If the analyzed cooling water detects a benzene concentration greater than 0.013 ppmw (or 13.0 ppb), the analyzer shall be used to help determine the area of the plant site from which the leak into the cooling water system has occurred. A sampled benzene concentration of greater than 0.013 ppmw on five consecutive days shall be considered a leak. If a benzene leak is detected, the owner or operator shall comply with the requirements contained in Special Condition No. 24A, except as provided in Special Condition No. 24B through E.

    If the repair of a leaking component is to be delayed, documentation of a decision to delay repair shall state the reasons repair was delayed and shall specify a schedule for completing the repair as soon as practical. For the purposes of this permit condition, delay of repair means exceeding the time frame established in Special Condition No. 24A. Prior to exceeding the time frame established in Special Condition No. 24A, all documentation of a decision to delay repair shall be submitted to the TNRCC Beaumont Regional Office for approval.

    If a leak is not detected during the first six-month period of mass spectrophotometer sample analysis, the mass spectrophotometer sample analysis frequency may be changed to quarterly if the mass spectrophotometer results agree with the gas chromatography results within 10 percent. The mass spectrophotometer sample analysis frequency shall return to monthly if the gas chromatography results differ with the mass spectrophotometer results by more than 10 percent. **(N, 3/99)**

26. Heat exchangers involved in the cooling water cycle shall be of welded construction and inspected during all planned shutdowns but no later than a five-year cycle. **(N)**

27. Within 180 days after the start of operations, the holder of this permit shall submit to the TNRCC Regional Director, or designated representative, documentation which demonstrates the permit holder is achieving compliance with all general and special conditions. This documentation will consist of a detailed statement explaining how each requirement in a condition is met. It will also include a sample of each record sheet required to be maintained by any condition, NESHAPS, and NSPS requirements and a listing of all testing required with test dates. **(PSD, N)**

28. The holder of this permit shall forward to the staff of the TNRCC more detailed engineering and emissions data on the following equipment as it becomes available, but prior to start of construction of the Decoke Drum (N-18). This information shall include (but is not limited to) best available control technology analysis, emission calculations, and applicable TNRCC technical tables. If the new information produces a change in emission rates when compared to the MAERT of this permit, the holder of this permit shall revise the permit application to include the new information, or submit a permit amendment application (if emissions increase above MAERT values), and update any prevention of significant deterioration/nonattainment netting calculations provided in support of this permit. **(PSD, 9/00)**

INITIAL DETERMINATION OF COMPLIANCE

29. Sampling ports and platform(s) shall be incorporated into the design of the nine Ethylene Cracking Furnaces (identified as N-1 through N-9), two Heaters (N-12 and N-13), the Condensate Splitter Heater (N-17), the Supplemental Boiler (N-14), the Thermal Oxidizer (N-19), the Vapor Combustor (22BZNTKFLR), and the Cogeneration Trains (N-20A and N-20B) stacks according to the specifications set forth in the attachment entitled "Chapter 2, Stack Sampling Facilities." Alternate sampling facility designs may be submitted for approval by the TNRCC Regional Director or the Manager of the TNRCC Engineering Services Team. **(PSD, N, 9/00)**

30. The holder of this permit shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the Ethylene Cracking Furnaces (N-1 through N-9), Heaters (N-12 and N-13), Condensate Splitter Heater (N-17), the Supplemental Boiler (N-14), the Thermal Oxidizer (N-19), the Vapor Combustor (22BZNTKFLR), and the Cogeneration Trains (N-20A and N-20B) stacks. Sampling shall be conducted in accordance with the appropriate procedures of the TNRCC Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods 201A and 202 or Reference Method 5, modified to include back-half condensibles, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}); Reference Method 8 or Reference Methods 6 or 6c for sulfur dioxide (SO_2); Reference Method 9 for opacity (consisting of 30 six-minute readings as provided in 40 CFR 60.11[b]); Reference Method 10 for the concentration of CO; Reference Method 25A, modified to exclude methane and ethane, for the concentration of VOC (to measure total carbon as propane); and Reference Method 20 for the concentrations of NO_X and O_2 or equivalent methods.
Fuel sampling using the methods and procedures of 40 CFR 60.335(d) for the cogeneration trains may be conducted in lieu of stack sampling for SO_2. If fuel sampling is used, compliance with NSPS, Subpart GG, SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2. Any deviations from those procedures must be approved by the Executive

Director of the TNRCC prior to sampling. The TNRCC Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling. **(9/00)**

A. The appropriate TNRCC Regional Office in the region where the source is located shall be contacted as soon as testing is scheduled, but not less than 45 days prior to sampling to schedule a pretest meeting.

The notice shall include:

(1) Date for pretest meeting.
(2) Date sampling will occur.
(3) Name of firm conducting sampling.
(4) Type of sampling equipment to be used.
(5) Method or procedure to be used in sampling.
(6) Procedure used to determine turbine loads during and after the sampling period.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. A written proposed description of any deviation from sampling procedures specified in permit conditions or TNRCC or EPA sampling procedures shall be made available to the TNRCC prior to the pretest meeting. The TNRCC Regional Director or the Manager of TNRCC Enforcement Division, Engineering Services Team in Austin shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in B of this condition shall be submitted to the TNRCC Office of Permitting, Remediation, and Registration, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the TNRCC Enforcement Division, Engineering Services Team in Austin. **(4/99)**

B. Air contaminants emitted from the Ethylene Cracking Furnaces (N-1 through N-9), Heaters (N-12 and N-13), Condensate Splitter Heater (N-17), and Supplemental Boiler (N-14) to be tested for include (but are not limited to) NO_x, CO, SO_2, and PM_{10}.
Air contaminants emitted from the Thermal Oxidizer (N-19) and the Cogeneration Trains (N-20A and N-20B) to be tested for include (but is not limited to) NO_x, CO, SO_2, and VOC.
Air contaminants emitted from the Vapor Combustor (22BZNTKFLR) to be tested for includes (but is not limited to) NO_x, CO, and VOC. **(9/00)**

C. Sampling shall occur within 60 days but not later than 180 days after initial start-up of the

Ethylene Cracking Furnaces (N-1 through N-9), Heaters (N-12 and N-13), Condensate Splitter Heater (N-17), Supplemental Boiler (N-14), Thermal Oxidizer (N-19), the Vapor Combustor (22BZNTKFLR), and the Cogeneration Trains (N-20A and N-20B) and at such other times as may be required by the Executive Director of the TNRCC. Requests for additional time to perform sampling shall be submitted to the TNRCC Regional Office. Additional time to comply with the applicable requirements of 40 CFR 60 and 40 CFR 61 requires EPA approval, and requests shall be submitted to the TNRCC Enforcement Division, Engineering Services Team in Austin. **(9/00)**

D. The Ethylene Cracking Furnaces (N-1 through N-9), Heaters (N-12 and N-13), Condensate Splitter Heater (N-17), Supplemental Boiler (N-14), the Thermal Oxidizer (N-19), the Vapor Combustor (22BZNTKFLR), and the Cogeneration Trains (N-20A and N-20B) shall operate at maximum production rates and/or fill rates during stack emission testing. Each gas turbine shall be tested at a minimum of four points in the normal operating range including the minimum point in the range and at full load for the atmospheric conditions which exist during testing. The duct burner shall be tested at its maximum firing rate while the turbine is operating at base load. Primary operating parameters that enable determination of production rate shall be monitored and recorded during the stack test. These parameters are to be determined at the pretest meeting. If the plant is unable to operate at maximum rates during testing, then future production rates may be limited to the rates established during testing. Additional stack testing may be required when higher production rates are achieved. **(9/00)**

E. Three copies of the final sampling report shall be forwarded to the TNRCC within 45 days after sampling is completed. Sampling reports shall comply with the attached provisions of Chapter 14 of the TNRCC Sampling Procedures Manual. The reports shall be distributed as follows: **(4/99)**

One copy to the TNRCC Beaumont Regional Office.
One copy to the TNRCC Austin Enforcement Division, Engineering Services Team.
One copy to the EPA Region 6 Office, Dallas. **(PSD, N)**

CONTINUOUS DETERMINATION OF COMPLIANCE

31. The holder of this permit shall install, calibrate, and maintain a continuous emission monitoring system (CEMS) to measure and record the in-stack concentrations of NO_x, CO, SO_2, and O_2 from each of the Ethylene Cracking Furnaces (N-1 through N-9), the Condensate Splitter Heater (N-17), the Supplemental Boiler (N-14), and the Cogeneration Trains (N-20A and N-20B). Fuel sampling required by 40 CFR 60.335(d) for the cogeneration trains may be used in lieu of CEMS for SO_2. In addition, the Thermal Oxidizer (N-19) shall be equipped with CEMS for CO and O_2. Note: As an alternative to installing a SO_2 CEMS on the Condensate Splitter Heater (N-17), the holder of this permit may verify compliance of SO_2 from the Condensate Splitter Heater by continuously monitoring and recording the concentration of H_2S in the fuel gas prior to combustion (as specified in 40 CFR 60.105(a)(4); however, H_2S concentrations averaged over a one hour time period will be used to show compliance). **(9/00)**

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

    B. (1) For sources subject to the quality-assurance requirements of 40 CFR 60, Appendix F*, the following applies:

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

        (2) For sources not subject to the quality-assurance requirements of 40 CFR 60, Appendix F*, the following applies:

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

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

All CGA exceedances of ±15 percent accuracy and any CEMS downtime shall be reported to the appropriate TNRCC Regional Director, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TNRCC Regional Director.

* 40 CFR 60, Appendix F applies only to those sources for which an NSPS subpart specifically requires both a continuous monitoring system and that the continuous monitoring system be used to demonstrate compliance with emission limits on a continuous basis.

C. The monitoring data shall be reduced to hourly average concentrations at least once everyday, using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of the permit allowable emission rate in lbs/hr and lb/MMBtu at least once everyday and cumulative TPY on a 12-month rolling average at least once every month. At least 23 hourly averages shall be generated per day. The technique used to convert ppmv to mass emission rates lb/MMBtu shall be Method 19. Conversion from lb/MMBtu to lb/hr shall be based on each furnaces measured firing rate and the corresponding Btu content of the fuel.

D. All monitoring data and quality-assurance data shall be maintained by the source for a period of two years and shall be made available to the TNRCC Executive Director or his designated representative upon request. The data from the CEMS may, at the discretion of the TNRCC, be used to determine compliance with the conditions of this permit.

E. The appropriate TNRCC Regional Office shall be notified at least 30 days prior to any

required RATAs in order to provide them the opportunity to observe the testing. **(N)**

32. The holder of this permit shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly fuel consumption in each cogeneration train. **(PSD, N, 4/99)**

33. The NH_3 concentration in the CTG/HRSG Unit 2 Exhaust Stack (EPN N-20B) shall be tested or calculated according to the method and frequency listed below:

    A. If a sorbent tube device specific for NH_3 is used, the frequency of the sorbent tube testing shall be daily for the first 60 days of cogeneration operation, after which, the frequency of the sorbent tube testing may be reduced from daily to weekly after operating procedures have been developed to prevent excess amounts of NH_3 from being introduced in the SCR unit and when operation of the SCR unit has been proven successful with regard to controlling NH_3 slippage. Daily sorbent tube testing shall resume when the catalyst is within 30 days of its useful life expectancy.

    B. As an approved alternative to sorbent tube testing, the permit holder may install and operate a second NO_x CEMS probe located between the duct burners and the SCR, upstream of the stack NO_x CEMS, which may be used in association with the SCR efficiency and NH_3 injection rate to estimate NH_3 slip. This condition shall not be construed to set a minimum NO_x reduction efficiency on the SCR unit.

    C. If the measured or calculated NH_3 slip concentration exceeds 6 ppmvd @ 15 percent O_2 at any time, the permit holder shall conduct testing by either the Phenol-Nitroprusside Method or the Indophenol Method on a quarterly basis. These results shall be recorded and used to determine compliance with Special Condition No. 16.

    D. Any other method used for measuring NH_3 slippage shall require prior approval from the TNRCC. **(PSD, N, 4/99)**

34. The holder of this permit shall either measure or develop a program to calculate the total mass flow rate through the HRSG stacks to ensure continuous compliance with the emission limitations specified in the attached MAERT.

A. The exhaust emissions from CTG/HRSG Unit 1 and CTG/HRSG Unit 2 shall be calculated on an hourly basis in pounds per hour using the measured or calculated flow rate as provided for by EPA Reference Method 19 and natural gas flow rates and the concentrations of NO_x and CO from the CEMS required in Special Condition No. 31.

B. The hourly calculated values will be cumulatively added during each hour of the month and stored in the computer hard drive and on individually stored discs or other TNRCC-accepted computer media. Records of this information will also be available in a form suitable for inspection. **(PSD, N, 4/99)**

RECORDKEEPING REQUIREMENTS

35. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the TNRCC, EPA, or any air pollution control agency with jurisdiction.

A. A copy of this permit.

B. Permit application and subsequent representations submitted.

C. A complete copy of the testing report and records of the initial performance testing completed pursuant to Special Condition No. 30 to demonstrate initial compliance.

D. Stack sampling results or other testing that may be conducted on units authorized under this permit after the date of issuance of this permit. **(PSD, N, 4/99)**

36. In addition to recordkeeping requirements contained in the conditions of this permit, the following information shall be recorded and maintained by the permit holder for a period of two years and shall be maintained at the plant site and made available to a representative of the TNRCC, EPA, or any air pollution control agency with jurisdiction upon request.

A. The average hourly NO_x and CO emissions in lb/MMBtu of heat input for each Ethylene Cracking Furnace (N-1 through N-9), Condensate Splitter Heater (N-17), and Supplemental Boiler (N-14).

B. The NO_x, CO, and diluent gases, O_2 or CO_2, CEMS emissions data to demonstrate compliance with the emission rates listed in the MAERT.

C. Raw data files of all CEMS data including calibration checks and adjustments and

maintenance performed on these systems.

D. Records of the hours of operation and average daily quantity of natural gas-fired in the turbines and HRSG duct burners.

E. Records of fuel sampling conducted pursuant to Special Condition No. 30.

F. Records of NH_3 emissions sampling and calculations pursuant to Special Condition No. 33.

G. Written records of any accidental releases, spills, or venting of NH_3, and the corrective action taken. **(PSD, N, 4/99)**

REPORTING

37. The holder of this permit shall comply with the reporting and recordkeeping requirements of 40 CFR 60.7. Such reports are required for each emission unit which is required to be continuously monitored pursuant to Special Condition No. 31. Each report shall contain the hours of operation of the facility, a report summary of the periods of non-complying emissions, and CEMS downtimes by cause, in addition to the information specified in 40 CFR 60.7. Non-complying NO_x, CO, and SO_2 emissions are any period of continuous operation except during start-up or shutdown. For reporting purposes, non-complying emissions are defined as:

A. Each one-hour period of operation, except during start-up or shutdown, during which the average emissions of NO_x, CO, or SO_2 as measured and recorded by each CEMS, exceed the emission limits of Special Condition No. 19 or the MAERT.

B. Annual emissions shall be defined as a rolling 12-month period during which the 12-month cumulative emissions of NO_x, CO, or SO_2 as measured and recorded by each CEMS, exceed the emission limits of Special Condition No. 19 or the MAERT.

C. If the average NO_x, CO, or NH_3 stack outlet concentration for the cogeneration trains exceeds permitted concentrations identified in Special Condition No. 16 for more than one hour, the holder of this permit shall investigate and determine the reason for the exceedance and, if needed, make necessary repairs to the SCR unit and/or its associated equipment as soon as possible. The holder of this permit will take appropriate steps, as necessary, to ensure the SCR unit is operating in compliance until repairs can be made. If the NO_x, CO, or NH_3 concentrations exceed the concentrations required by Special

Condition No. 16 for more than 24 hours, the permit holder shall notify the TNRCC Regional Office either verbally or with a written report detailing the cause of the increase in emissions and all efforts being made to correct the problem. **(PSD, N, 4/99)**

Dated