

Appendix B

Ohio Air Quality Analysis

APPENDIX B

Air Quality Analysis for TFO Permit Application

B.1 INTRODUCTION

This appendix provides the ambient air quality impact assessment as required by the Ohio EPA consistent with their Engineering Guide #69. Prevention of Significant Deterioration (PSD) modeling is not required because all regulated pollutants have net emissions below the PSD significant emission rates. Ohio modeling is required for SO₂ because the project net increase in emissions is greater than the pollutant-specific Ohio Modeling Significant Emission Rates provided in Engineering Guide #69. The Ohio specific modeling ensures that the impact of the project will not exceed the Ohio Acceptable Incremental Impacts.

A summary of the project’s emissions in comparison to the applicable significance levels is presented in Table B-1 below. As indicated in the table below, SO₂ requires modeling for the Ohio air quality impact analysis.

Table B-1: Summary of Project Emissions Compared to Modeling Thresholds

	Emissions (Tons per Year)					
	NO _x	SO ₂	CO	PM ₁₀	VOC	GHG
Project Emissions (<i>after netting</i>)	-404.5	37.2	-64.5	0.5	34.9	118,283
PSD Significance Emission Rates	40	40	100	15	NA	NA
<i>Is PSD Modeling Required?</i>	<i>No</i>	<i>No</i>	<i>No</i>	<i>No</i>	<i>NA</i>	<i>NA</i>
Ohio Modeling Significance Emission Rates	25	25	100	10	NA	NA
<i>Is Ohio Modeling Required?</i>	<i>No</i>	<i>Yes</i>	<i>No</i>	<i>No</i>	<i>NA</i>	<i>NA</i>

A screening-level air quality impact analysis was performed to assess the impact of the proposed project emissions of SO₂ on the ambient air quality. A description of the modeling approach and data used for the assessment of air quality impact is included in the following sections. The results of this evaluation show that the results for SO₂ were less than then Ohio significant impact levels.

Additionally, increases in air toxics from new projects that exceed one ton per year (1 tpy) (except for those from fossil fuel combustion) are required by Ohio’s air

toxic policy to be evaluated to determine if the Maximum Acceptable Ground-Level Concentration (MAGLC) has been exceeded. As such, increased emissions of H₂S from the coke cutting water drained to the coker coke pit were evaluated. Emission rates of project air toxic's and the results of air toxic modeling of H₂S are presented in Section B.4.2.

B.2 Description of Air Quality Dispersion Model

Dispersion modeling for this project was performed using U.S. EPA SCREEN3 dispersion model. There are a variety of U.S. EPA air dispersion models for estimating ambient air impacts from releases of air contaminants by industrial processes. SCREEN3, a simplified version of ISC3 that requires few inputs and yields conservative results is available and approved for use by U.S. EPA for initial modeling.

SCREEN3 is a single source Gaussian plume model which predicts maximum ground-level concentrations for point, area, flare, and volume sources, as well as concentrations in the cavity zone, and concentrations due to inversion break-up and shoreline fumigation. Since SCREEN3 can only model one emissions source at a time, the combined ambient impact from multiple emissions sources can be conservatively estimated using SCREEN3 by adding together the model results for each emissions source modeled separately. This is a conservative approach because the maximum impacts would not actually occur at the same location for all sources. Due to the relative ease with which SCREEN3 modeling can be completed, it has been used to determine a conservative estimate of air quality impacts from steady state air emissions sources.

B.3 Data for Air Quality Impact Assessment

B.3.1 Emissions Data

For simplicity, a unitized emission rate of 1 gram per second (g/s) was used in the SCREEN3 model as the modeled emissions rate for each project affected emissions source with an increase in SO₂ emissions. This unitized modeling yields a model output predicted ambient impact in units of microgram/cubic meter (µg/m³) concentration per gram/second (g/s) emissions rate. The resulting maximum predicted ambient concentration for each source was then multiplied by the project source emissions rate (g/s) to determine the predicted impact of that source. This methodology is consistent with the linear nature of Gaussian models such as SCREEN3, in which the impacts vary in direct proportion to the emissions rate, and is also referenced in OEPA Engineering

Guide #69. Table B-2 summarizes project emissions used in this modeling assessment by source.

Table B-2: Project SO₂ Emissions by Source

Source Description	SO₂ emissions (lb/hr)	SO₂ emissions (tpy)
New Crude 1 Heaters	8.25	15.61
Existing Crude 1 Heater	NA	-36.56
New Vac 1 Heater	4.67	5.2
Existing Vac 1 Heater	NA	-11.25
Coker 3 Heater	NA	-11.88
ADHT Heater	0.53	0.51
Alstom Boilers	5.02	2.13
SRU 1, SRU 2&3	NA	47.18

Annual SO₂ emissions from the above heaters was estimated consistent with BPH's proposed new SO₂ limits on these heaters which requires long term (annual) emissions performance better than required by applicable NSPS standards. In order to reflect the maximum emissions for the short-term (24-hr and 3-hr) averaging periods for SO₂, BPH used short term rates (pound per hour SO₂ emissions in Table B-2) based on the short term NSPS Ja standard of 162 ppm H₂S and the maximum firing rates. This was only applicable to fuel gas combustion sources with an increase in annual emissions for the TFO project. For the long-term annual average period, the annual SO₂ emissions increase from the project was used.

B.3.2 Stack Data

Site-specific stack parameters were used for each source. Table B-3 includes the stack data that was used for the air quality impact assessment.

Table B-3: Project Source Stack Data

Equipment Name	Type	Shape	Height (ft)	Diameter (ft)	Exit Gas T @ Max (K)	Exit Gas Flow @ Max (acfm)	Distance to nearest fenceline (ft)
New Crude Heaters	Vertical	Round	270	8	450	6500	1817
New Vac Heater	Vertical	Round	230	6	450	4300	1817
ADHT Heater	Vertical	Round	100	3.5	700	10,306	1342
Alstom Boilers	Vertical	Round	100	6.25	428	105,000	1444
SRU1 & SRU 2&3	Vertical	Round	228	3.5	810	31,923	873

In order to simplify the presentation of the modeling results, the emissions from the new Crude 1 heaters exhaust are shown as if they vented through only one stack. Similarly, the Alstom Boilers and the SRU 1/ SRU 2&3 are shown as if exhausted through only one stack. Since all maximum impacts are added together (regardless of their location), the spatial differences in stack locations is unimportant.

The design for the new Crude 1 and Vacuum 1 heaters is to have stacks taller than 213 feet (65 meters). However, consistent with US EPA/OEPA guidance, the modeling was performed at 65 meters which is the maximum allowable modeled height unless a GEP analysis supports the need for a higher stack to avoid building downwash (which it did not in this case).

B.3.3 Building Downwash Analysis

A generalized formula has been designed to establish the minimum release or stack height necessary to avoid the aerodynamic downwash phenomenon. This height is defined as GEP stack height. The determination of GEP stack height for an emission source is based on the following empirical equation:

$$H_g = H_b + 1.5 l_b$$

where,

H_g = GEP stack height;

H_b = Height of the structure on which the source is located, or nearby structure;

and

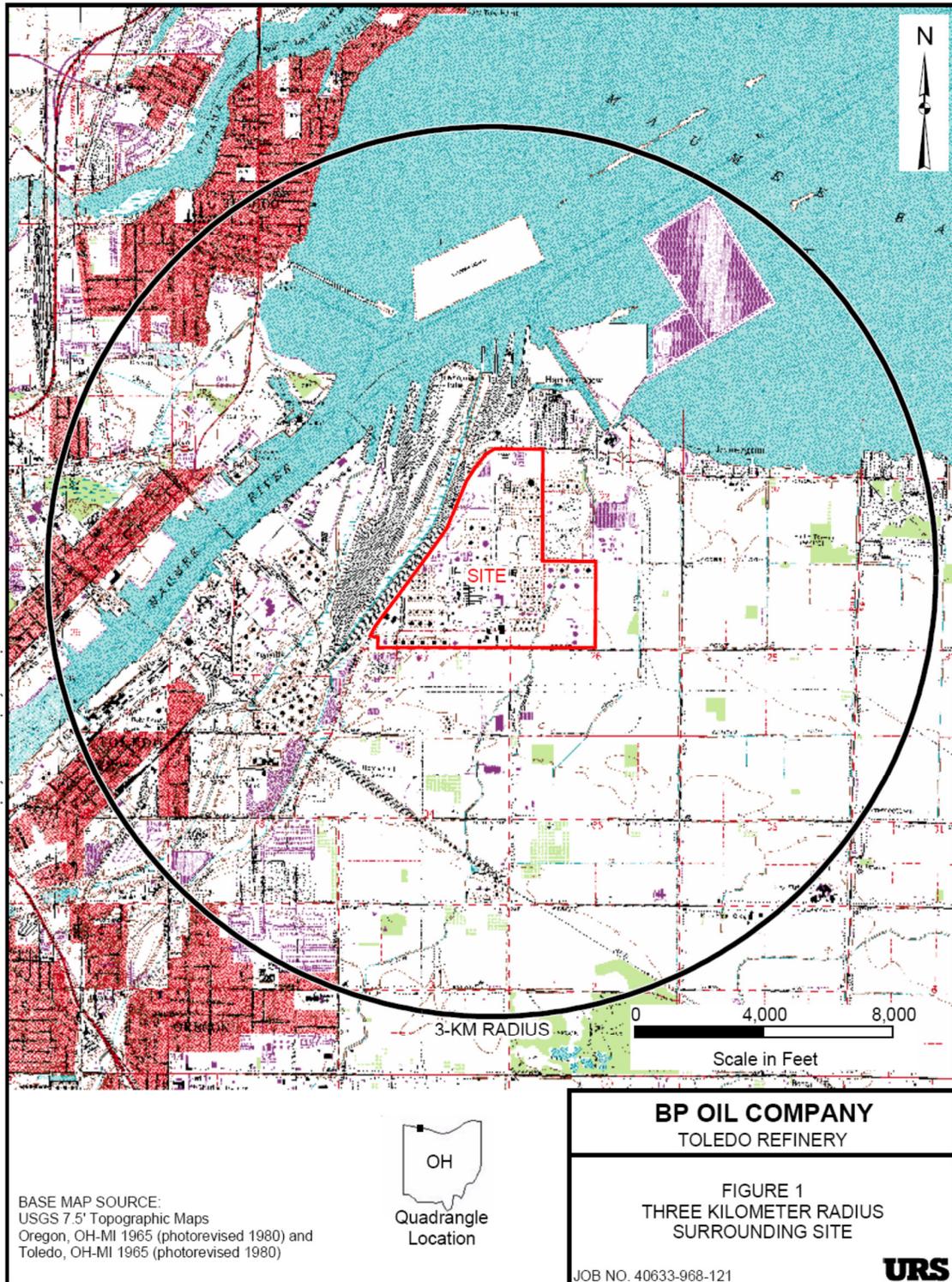
$l_b =$ Lesser dimension (height or projected width) of the structure on which the source is located, or nearby structure.

The Coker 3 bubble tower was determined to be the largest, most influencing structure for the new Crude 1 and Vacuum 1 heaters in the surrounding area. The Coker 3 bubble tower has an estimated structure height of 116 feet and maximum projected width of 18 feet. The above formula yields a GEP stack height for this structure of 143 feet. The stacks on the new Crude heaters are currently designed for 270 feet. Similarly, the stack on the new Vac 1 heater is currently designed for 230 feet. These stack heights are above the height calculated as necessary to avoid building downwash. Consequently, downwash effects should not influence the air quality modeling. Nevertheless, the dimensions for this nearby structure were input into the SCREEN3 model and the downwash features of the model were used to assure that any slight affects would be addressed.

B.3.4 Land Use Classification

The BP-Husky refinery has historically been classified as rural for modeling purposes based on a technique developed by Irwin (1979). The classification can be based on either average heat flux, land use, or population density within a 3-km radius from the site. Of these, the U.S. EPA has specified that land use is the most definitive criterion (U.S. EPA, 1986). Using the meteorological land use typing scheme established by Auer (1978) within a 3-km radius from the site, an urban classification of the site area requires more than 50 percent of the following land use types: heavy industrial (I1), light-moderate industrial (I2), commercial (C1), single-family compact residential (R2), and multi-family compact industrial (R3). Otherwise, the site area is considered rural. As shown in below Figure B-1, most of the area around the site is undeveloped, agricultural, or open waters. Since these non-urban land use types comprise more than 50 percent of the total area in the vicinity of the proposed facility, rural dispersion coefficients were employed in the model to calculate plume dispersion.

Figure B-1 Surrounding Land Use



B.3.5 Receptors and Terrain

SCREEN3 was executed for simple terrain using the full default meteorological data, and assuming rural mode.

B.4 AMBIENT AIR QUALITY MODELING RESULTS

B.4.1 Ohio Air Quality Impact of SO₂

Emissions of SO₂ were modeled using the emission and stack data described in Tables B-2 and B-3. The purpose of this analysis was to evaluate if the maximum incremental impact of total emissions from the TFO project will exceed the Ohio Acceptable Incremental Impact provided in Engineering Guide #69.

The results of this analysis is summarized below and the SCREEN3 Input and Output information and spreadsheets used to convert and compare the model output to the units of applicable standards are presented at the end of this Appendix. The Ohio EPA requires that the emission increases from new or modified sources be evaluated to determine if the maximum incremental impact of total emissions will exceed the Ohio Acceptable Incremental Impact. The applicable increments and the modeled results for this project are shown below in Table B-4.

Table B-4: Modeling Results Compared to Ohio EPA Thresholds

Pollutant	Averaging Period	Ohio Acceptable Incremental Impact* (µg/m³)	TFO Project Modeled Impacts (µg/m³)	% of Threshold
SO ₂	Annual	10	1.40	14%
	24-hr	45.5	19.6	43%
	3-hr	256	44.2	17%

*Established in Ohio's Engineering Guide #69

As illustrated in Table B-4, the proposed project's modeled emission results indicate that predicted SO₂ concentrations are below the Ohio Acceptable Incremental Impacts, and no further analysis is needed. This analysis used the conservative SCREEN3 model the very conservative assumption that the maximum predicted impact from each source occurred at the exact same location as the maximum impact of every other emission source. Consequently, actual expected impacts should be much lower.

B.4.2 Ohio Air Toxics Analysis

In accordance with Ohio EPA's Engineering Guide #69, increases in air toxics from new projects that exceed one ton per year (1 tpy) should be evaluated to determine if the Maximum Acceptable Ground-Level Concentration (MAGLC) has been exceeded. A summary of the project's most significant air toxic emissions in comparison to the applicable significance levels are presented in Table B-5 below. Hexane and formaldehyde are the two largest HAP byproducts of fuel gas combustion. H₂S is evaporates from cutting water used in the coker coke pit.

Table B-5: Summary of Project Significant Air Toxic Emissions

Emissions Source	Hexane tpy	Formaldehyde tpy	H2S tpy
New Crude 1 Heater	3.48	0.14	NA
New Vacuum 1 Heater	1.16	0.05	NA
Coker 3 Heater	0.15	0.01	NA
ADHT Heater	0.08	0.003	NA
Steam Boilers	0.48	0.02	NA
SRU (fuel combustion emissions)	0.13	0.01	NA
Coker 3 Coke Pit	NA	NA	1.8
Project Air Toxic Emissions	5.48	0.23	1.8
Ohio Air Toxic Modeling Emission Rate	<i>1 tpy</i>	<i>1 tpy</i>	<i>1 tpy</i>
<i>Is Ohio Toxics Modeling Required?</i>	<i>No*</i>	<i>No</i>	<i>Yes</i>

*NOTE: ORC 3704.03(F)(f)(i) states that the air toxics policy does not apply to air contaminant sources that combust fossil fuels. Therefore, the increase in air toxic emissions from the combustion of fossil fuels (hexane and formaldehyde) from the affected project heaters is not required.

As indicated in the table above, the only toxic that requires modeling is H₂S. A screening-level air quality impact analysis was performed using U. S. EPA's SCREEN3

model to assess the impact of the proposed project emissions of H₂S on the ground-level concentration of air toxics. Modeling inputs are summarized in Table B-9.

Table B-3: Project Source Stack Data

Source Name	Type	Release Height (ft)	Initial Lateral Dimension (ft)	Initial Vertical Dimension (ft)	Distance to nearest fence line (ft)
Coker 3 Coke Pit	Volume	0	22.325	1.906	1207

Table 1 of the SCREEN3 User’s Guide, dated September 1995, provides suggested procedures for estimating the initial lateral dimensions and initial vertical dimensions for volume source plumes. For a single volume source, the initial lateral dimension is estimated by dividing the length of side by 4.3. The Coker 3 Coke Pit is approximately 96 feet by 133 feet. For conservatism, it is assumed that the side of the Coke Pit is equal to 96 feet. The initial vertical dimension of a surface-based source is estimated by taking the vertical dimension of the volume source and dividing it by 2.15. The Coker 3 Coke Pit is a three sided enclosed pit with walls approximately 14 feet tall. Since it is not fully enclosed on all four sides, BPH assumed a vertical dimension of 7 feet.

The modeled emissions were compared to the Maximum Acceptable Ground-Level Concentration (MAGLC). The Maximum Acceptable Ground-Level Concentration (MAGLC) was calculated based on the Threshold Limit Value (TLV) and Ohio EPA methodology provided in *Option A, Review of New Sources of Air Toxic Emissions.*) The TLV value used in this analysis is from the American Conference of Governmental Industrial Hygienists (ACGIH) and represents the maximum concentration that nearly all workers may be exposed to on the basis of an 8 hour per day, 40 hour per week work schedule without adverse effects. The TLV value used was published in 2006 by ACGIH.

The MAGLC was calculated using the following formula (for a continuous emitting source):

$$\text{MAGLC} = \frac{\text{TLV}}{10} \times \frac{8 \text{ hours}}{24 \text{ hours}} \times \frac{5 \text{ days}}{7 \text{ days}} \times \frac{\text{TLV}}{42}$$

From the Option A guidance, Ohio EPA requires a source to compare the maximum predicted on-hour concentration under worst-case meteorology to the

estimated MAGLC above to determine the ambient air quality effects of a new project. Table B-9 shows the MAGLC value calculated for H₂S.

B-9: Air Toxic Pollutant Thresholds

Pollutant	TLV (ppm)	TLV (µg/m³)	MAGLC (Calculated) (µg/m³)
H ₂ S	10	13,926	331.6

Note: The concentration of TLV in PPM is converted to µg/m³ by multiplying PPM by the molecular weight of the compound (g/gmole), dividing by 24.45 liters/gmole, and multiplying by 1000 (liters/m³).

The highest predicted potential ground-level concentration for H₂S compared to the corresponding Maximum Acceptable Ground Level Concentration (MAGLC) is shown in Table B-10

Table B-10: Air Toxics Analysis Results

Air Toxic	Project Emissions	TFO Maximum Predicted Concentration	Ohio MAGLC (Annual)
	(g/s)	(µg/m³)	(µg/m³)
H ₂ S	0.052	122.1	331.6

As shown in the table above, the modeled maximum ground-level concentrations for H₂S is below the calculated MAGLC. Based on the Ohio EPA Air Toxics Policy, no further analysis is necessary.

REFERENCES

- American Conference of Governmental Industrial Hygienist (2006): "2006 TLVs and BELs: Based on the Documentation of the Threshold Limit Values for Chemical Substances and Physical Agents, Biological Exposure Indices," Cincinnati, OH: ACGIH Worldwide
- Auer, A. H. (1978): "Correlation of Land Use and Cover with Meteorological Anomalies," *Journal of Applied Meteorology*, Volume 17, pp. 636-643.
- Hazardous Substances Data Bank (HSDB), a database of the National Library of Medicine's TOXNET system (<http://toxnet.nlm.nih.gov>)
- Irwin, J.S. (1979): "Proposed Criteria for Selection of Urban Versus Rural Dispersion Coefficients," Meteorology and Assessment Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.
- Ohio Environmental Protection Agency (2003): "Engineering Guide #69, Air Dispersion Modeling Guidance," Division of Air Pollution Control Air Quality Modeling and Planning Section
- Ohio Environmental Protection Agency (1997): "Option A, Review of New Sources of Air Toxic Emissions", Division of Air Pollution Control, Columbus, OH
- Technology Transfer Network (2008): Support Center for Regulatory Atmospheric Modeling web-based documents,
http://www.epa.gov/scram001/dispersion_screening.htm,
http://www.epa.gov/scram001/dispersion_screening.htm,
http://www.epa.gov/scram001/guidance/guide/appw_05.pdf
- United States Environmental Protection Agency (1992): "Screening Procedures for estimating the Air Quality Impact of Stationary Sources, Revised," EPA-454/R-92-019

Attachment 1:
SCREEN3 Output

09/20/12

11:37:45

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

C:\Lakes\Screen View\New Crude.scr

SIMPLE TERRAIN INPUTS:

SOURCE TYPE = POINT
EMISSION RATE (G/S) = 1.00000
STACK HEIGHT (M) = 65.0000
STK INSIDE DIAM (M) = 2.4384
STK EXIT VELOCITY (M/S) = 0.6569
STK GAS EXIT TEMP (K) = 449.8167
AMBIENT AIR TEMP (K) = 293.0000
RECEPTOR HEIGHT (M) = 0.0000
URBAN/RURAL OPTION = RURAL
BUILDING HEIGHT (M) = 36.5800
MIN HORIZ BLDG DIM (M) = 5.4900
MAX HORIZ BLDG DIM (M) = 5.4900

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

STACK EXIT VELOCITY WAS CALCULATED FROM
VOLUME FLOW RATE = 3.0676556 (M**3/S)

BOUY. FLUX = 3.338 M**4/S**3; MOM. FLUX = 0.418 M**4/S**2.

*** FULL METEOROLOGY ***

*** SCREEN AUTOMATED DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M ³)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH	----
1.	0.000	1	1.0	1.1	320.0	106.91	0.73	0.63	NO	
100.	0.5956E-03	1	3.0	3.4	960.0	74.09	27.20	14.60	NO	
200.	2.749	1	3.0	3.4	960.0	74.09	50.17	29.63	NO	
300.	9.244	1	2.0	2.3	640.0	82.30	72.07	47.90	NO	
400.	13.84	1	1.0	1.1	320.0	106.91	93.65	72.39	NO	
500.	13.92	1	1.0	1.1	320.0	106.91	113.81	105.49	NO	
600.	10.92	2	1.0	1.1	320.0	106.91	98.39	63.80	NO	
700.	11.97	2	1.0	1.1	320.0	106.91	112.75	75.09	NO	
800.	11.86	2	1.0	1.1	320.0	106.91	126.91	86.59	NO	
900.	11.16	2	1.0	1.1	320.0	106.91	140.88	98.27	NO	
1000	10.23	2	1.0	1.1	320.0	106.91	154.69	110.10	NO	
1100	10.57	3	1.0	1.2	320.0	104.22	113.15	67.88	NO	
1200	10.71	3	1.0	1.2	320.0	104.22	122.36	73.32	NO	
1300	10.62	3	1.0	1.2	320.0	104.22	131.50	78.73	NO	

1400	10.36	3	1.0	1.2	320.0	104.22	140.57	84.11	NO
1500	10.01	3	1.0	1.2	320.0	104.22	149.58	89.47	NO
1600	9.598	3	1.0	1.2	320.0	104.22	158.54	94.81	NO
1700	9.160	3	1.0	1.2	320.0	104.22	167.44	100.13	NO
1800	8.713	3	1.0	1.2	320.0	104.22	176.29	105.42	NO
1900	8.271	3	1.0	1.2	320.0	104.22	185.09	110.69	NO
2000	7.842	3	1.0	1.2	320.0	104.22	193.85	115.94	NO
2100	7.430	3	1.0	1.2	320.0	104.22	202.56	121.17	NO
2200	7.039	3	1.0	1.2	320.0	104.22	211.24	126.38	NO
2300	6.670	3	1.0	1.2	320.0	104.22	219.87	131.57	NO
2400	6.324	3	1.0	1.2	320.0	104.22	228.46	136.75	NO
2500	6.163	4	1.0	1.3	320.0	100.06	157.01	59.02	NO
2600	6.216	4	1.0	1.3	320.0	100.06	162.65	60.47	NO
2700	6.250	4	1.0	1.3	320.0	100.06	168.26	61.91	NO
2800	6.265	4	1.0	1.3	320.0	100.06	173.86	63.32	NO
2900	6.265	4	1.0	1.3	320.0	100.06	179.43	64.73	NO
3000	6.252	4	1.0	1.3	320.0	100.06	184.99	66.11	NO
3500	6.011	4	1.0	1.3	320.0	100.06	212.49	72.39	NO
4000	5.665	4	1.0	1.3	320.0	100.06	239.58	78.33	NO
4500	5.286	4	1.0	1.3	320.0	100.06	266.30	83.99	NO
5000	4.911	4	1.0	1.3	320.0	100.06	292.69	89.42	NO
5500	4.556	4	1.0	1.3	320.0	100.06	318.80	94.64	NO
6000	4.228	4	1.0	1.3	320.0	100.06	344.63	99.69	NO
6500	3.928	4	1.0	1.3	320.0	100.06	370.22	104.57	NO
7000	3.657	4	1.0	1.3	320.0	100.06	395.57	109.31	NO
7500	3.410	4	1.0	1.3	320.0	100.06	420.72	113.91	NO
8000	3.188	4	1.0	1.3	320.0	100.06	445.68	118.40	NO
8500	2.986	4	1.0	1.3	320.0	100.06	470.44	122.79	NO
9000	2.803	4	1.0	1.3	320.0	100.06	495.04	127.07	NO
9500	2.637	4	1.0	1.3	320.0	100.06	519.46	131.26	NO
10000	2.503	5	1.0	1.9	10000.0	95.06	407.05	79.73	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 1. M:
446. 14.64 1 1.0 1.1 320.0 106.91 103.19 87.24 NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

*** SCREEN DISCRETE DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
772.	11.97	2	1.0	1.1	320.0	106.91	122.96	83.35	NO
781.	11.94	2	1.0	1.1	320.0	106.91	124.23	84.39	NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED

DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

*** REGULATORY (Default) ***
PERFORMING CAVITY CALCULATIONS
WITH ORIGINAL SCREEN CAVITY MODEL
(BRODE, 1988)

*** CAVITY CALCULATION - 1 ***	*** CAVITY CALCULATION - 2 ***
CONC (UG/M**3) = 3320.	CONC (UG/M**3) = 3320.
CRIT WS @10M (M/S) = 1.00	CRIT WS @10M (M/S) = 1.00
CRIT WS @ HS (M/S) = 1.45	CRIT WS @ HS (M/S) = 1.45
DILUTION WS (M/S) = 1.00	DILUTION WS (M/S) = 1.00
CAVITY HT (M) = 84.73	CAVITY HT (M) = 84.73
CAVITY LENGTH (M) = 25.61	CAVITY LENGTH (M) = 25.61
ALONGWIND DIM (M) = 5.49	ALONGWIND DIM (M) = 5.49

END OF CAVITY CALCULATIONS

*** SUMMARY OF SCREEN MODEL RESULTS ***

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
----- SIMPLE TERRAIN	----- 14.64	----- 446.	----- 0.
BLDG. CAVITY-1	3320.	26.	-- (DIST = CAVITY LENGTH)
BLDG. CAVITY-2	3320.	26.	-- (DIST = CAVITY LENGTH)

** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **

09/20/12

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*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

C:\Lakes\Screen View\New Vac.scr

SIMPLE TERRAIN INPUTS:

SOURCE TYPE = POINT
EMISSION RATE (G/S) = 1.00000
STACK HEIGHT (M) = 65.0000
STK INSIDE DIAM (M) = 1.8288
STK EXIT VELOCITY (M/S) = 0.7726
STK GAS EXIT TEMP (K) = 449.8167
AMBIENT AIR TEMP (K) = 293.0000
RECEPTOR HEIGHT (M) = 0.0000
URBAN/RURAL OPTION = RURAL
BUILDING HEIGHT (M) = 36.5800
MIN HORIZ BLDG DIM (M) = 5.4900
MAX HORIZ BLDG DIM (M) = 5.4900

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

STACK EXIT VELOCITY WAS CALCULATED FROM
VOLUME FLOW RATE = 2.0293722 (M**3/S)

BUOY. FLUX = 2.208 M**4/S**3; MOM. FLUX = 0.325 M**4/S**2.

*** FULL METEOROLOGY ***

*** SCREEN AUTOMATED DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
1.	0.000	1	1.0	1.1	320.0	96.04	0.67	0.55	NO
100.	0.8675E-03	1	3.0	3.4	960.0	71.69	27.05	14.32	NO
200.	3.278	1	3.0	3.4	960.0	71.69	50.08	29.48	NO
300.	11.64	1	1.5	1.7	480.0	83.86	72.06	47.88	NO
400.	17.06	1	1.0	1.1	320.0	96.04	93.22	71.83	NO
500.	15.42	1	1.0	1.1	320.0	96.04	113.46	105.10	NO
600.	14.20	2	1.0	1.1	320.0	96.04	97.98	63.16	NO
700.	14.53	2	1.0	1.1	320.0	96.04	112.39	74.54	NO
800.	13.75	2	1.0	1.1	320.0	96.04	126.59	86.12	NO
900.	12.54	2	1.0	1.1	320.0	96.04	140.59	97.85	NO
1000.	12.97	3	1.0	1.2	320.0	94.04	103.52	61.83	NO
1100.	13.10	3	1.0	1.2	320.0	94.04	112.83	67.34	NO
1200.	12.90	3	1.0	1.2	320.0	94.04	122.06	72.82	NO
1300.	12.49	3	1.0	1.2	320.0	94.04	131.22	78.27	NO
1400.	11.96	3	1.0	1.2	320.0	94.04	140.31	83.68	NO

1500.	11.37	3	1.0	1.2	320.0	94.04	149.34	89.07	NO
1600.	10.75	3	1.0	1.2	320.0	94.04	158.31	94.43	NO
1700.	10.15	3	1.0	1.2	320.0	94.04	167.22	99.76	NO
1800.	9.559	3	1.0	1.2	320.0	94.04	176.09	105.07	NO
1900.	8.998	3	1.0	1.2	320.0	94.04	184.90	110.36	NO
2000.	8.469	3	1.0	1.2	320.0	94.04	193.66	115.62	NO
2100.	7.973	3	1.0	1.2	320.0	94.04	202.38	120.87	NO
2200.	7.706	4	1.0	1.3	320.0	90.96	139.73	53.98	NO
2300.	7.776	4	1.0	1.3	320.0	90.96	145.45	55.51	NO
2400.	7.814	4	1.0	1.3	320.0	90.96	151.15	57.02	NO
2500.	7.824	4	1.0	1.3	320.0	90.96	156.81	58.50	NO
2600.	7.811	4	1.0	1.3	320.0	90.96	162.46	59.97	NO
2700.	7.777	4	1.0	1.3	320.0	90.96	168.08	61.42	NO
2800.	7.727	4	1.0	1.3	320.0	90.96	173.69	62.85	NO
2900.	7.663	4	1.0	1.3	320.0	90.96	179.27	64.26	NO
3000.	7.587	4	1.0	1.3	320.0	90.96	184.83	65.65	NO
3500.	7.077	4	1.0	1.3	320.0	90.96	212.35	71.97	NO
4000.	6.519	4	1.0	1.3	320.0	90.96	239.45	77.94	NO
4500.	5.977	4	1.0	1.3	320.0	90.96	266.19	83.63	NO
5000.	5.476	4	1.0	1.3	320.0	90.96	292.59	89.08	NO
5500.	5.023	4	1.0	1.3	320.0	90.96	318.70	94.33	NO
6000.	4.618	4	1.0	1.3	320.0	90.96	344.54	99.38	NO
6500.	4.257	4	1.0	1.3	320.0	90.96	370.13	104.28	NO
7000.	3.936	4	1.0	1.3	320.0	90.96	395.50	109.03	NO
7500.	3.650	4	1.0	1.3	320.0	90.96	420.65	113.65	NO
8000.	3.395	4	1.0	1.3	320.0	90.96	445.61	118.15	NO
8500.	3.166	4	1.0	1.3	320.0	90.96	470.38	122.54	NO
9000.	2.961	4	1.0	1.3	320.0	90.96	494.97	126.83	NO
9500.	2.776	4	1.0	1.3	320.0	90.96	519.41	131.03	NO
10000.	2.613	5	1.0	1.9	10000.0	92.09	407.02	79.57	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 1. M:
420. 17.24 1 1.0 1.1 320.0 96.04 97.51 78.35 NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

*** SCREEN DISCRETE DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
781.	13.95	2	1.0	1.1	320.0	96.04	123.91	83.90	NO
810.	13.64	2	1.0	1.1	320.0	96.04	128.00	87.28	NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED

DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

*** REGULATORY (Default) ***
PERFORMING CAVITY CALCULATIONS
WITH ORIGINAL SCREEN CAVITY MODEL
(BRODE, 1988)

*** CAVITY CALCULATION - 1 ***

CONC (UG/M**3) = 3320.
CRIT WS @10M (M/S) = 1.00
CRIT WS @ HS (M/S) = 1.45
DILUTION WS (M/S) = 1.00
CAVITY HT (M) = 84.73
CAVITY LENGTH (M) = 25.61
ALONGWIND DIM (M) = 5.49

*** CAVITY CALCULATION - 2 ***

CONC (UG/M**3) = 3320.
CRIT WS @10M (M/S) = 1.00
CRIT WS @ HS (M/S) = 1.45
DILUTION WS (M/S) = 1.00
CAVITY HT (M) = 84.73
CAVITY LENGTH (M) = 25.61
ALONGWIND DIM (M) = 5.49

END OF CAVITY CALCULATIONS

*** SUMMARY OF SCREEN MODEL RESULTS ***

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
----- SIMPLE TERRAIN	17.24	420.	0.
BLDG. CAVITY-1	3320.	26.	-- (DIST = CAVITY LENGTH)
BLDG. CAVITY-2	3320.	26.	-- (DIST = CAVITY LENGTH)

** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **

09/19/12

16:04:23

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

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SIMPLE TERRAIN INPUTS:

SOURCE TYPE = POINT
EMISSION RATE (G/S) = 1.00000
STACK HEIGHT (M) = 56.3880
STK INSIDE DIAM (M) = 1.9050
STK EXIT VELOCITY (M/S) = 5.9440
STK GAS EXIT TEMP (K) = 755.3720
AMBIENT AIR TEMP (K) = 293.0000
RECEPTOR HEIGHT (M) = 0.0000
URBAN/RURAL OPTION = RURAL
BUILDING HEIGHT (M) = 54.8600
MIN HORIZ BLDG DIM (M) = 12.1900
MAX HORIZ BLDG DIM (M) = 27.4300

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

BUOY. FLUX = 32.370 M**4/S**3; MOM. FLUX = 12.434 M**4/S**2.

*** FULL METEOROLOGY ***

*** SCREEN AUTOMATED DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
1.	0.000	0	0.0	0.0	0.0	0.00	0.00	0.00	NA
100.	3.481	6	2.5	6.5	10000.0	57.18	11.17	19.84	SS
200.	7.735	6	2.5	6.5	10000.0	59.41	17.87	25.97	SS
300.	9.321	5	4.0	7.3	10000.0	60.86	24.57	32.36	SS
400.	7.511	6	2.0	5.2	10000.0	68.05	28.69	32.69	SS
500.	7.002	6	2.0	5.2	10000.0	68.05	31.82	33.02	SS
600.	6.586	6	2.0	5.2	10000.0	68.05	34.91	33.35	SS
700.	6.241	6	2.0	5.2	10000.0	68.05	37.98	33.68	SS
800.	6.188	1	1.0	1.1	320.0	285.43	171.40	283.00	SS
900.	5.789	1	1.0	1.1	320.0	285.43	190.18	363.13	SS
1000.	5.475	6	2.0	5.2	10000.0	68.05	47.04	34.63	SS
1100.	5.282	6	2.0	5.2	10000.0	68.05	50.02	34.95	SS
1200.	5.143	6	1.5	3.9	10000.0	71.61	52.98	34.38	SS
1300.	5.021	6	1.5	3.9	10000.0	71.61	55.92	34.70	SS
1400.	4.911	6	1.5	3.9	10000.0	71.61	58.84	35.01	SS
1500.	4.811	6	1.5	3.9	10000.0	71.61	61.75	35.32	SS

1600.	4.719	6	1.5	3.9	10000.0	71.61	64.64	35.62	SS
1700.	4.634	6	1.5	3.9	10000.0	71.61	67.52	35.92	SS
1800.	4.555	6	1.5	3.9	10000.0	71.61	70.38	36.22	SS
1900.	4.482	6	1.5	3.9	10000.0	71.61	73.23	36.52	SS
2000.	4.413	6	1.5	3.9	10000.0	71.61	76.06	36.81	SS
2100.	4.348	6	1.5	3.9	10000.0	71.61	78.89	37.10	SS
2200.	4.287	6	1.5	3.9	10000.0	71.61	81.70	37.39	SS
2300.	4.229	6	1.5	3.9	10000.0	71.61	84.50	37.68	SS
2400.	4.174	6	1.5	3.9	10000.0	71.61	87.30	37.96	SS
2500.	4.122	6	1.5	3.9	10000.0	71.61	90.08	38.24	SS
2600.	4.071	6	1.5	3.9	10000.0	71.61	92.85	38.52	SS
2700.	4.023	6	1.5	3.9	10000.0	71.61	95.61	38.80	SS
2800.	3.977	6	1.5	3.9	10000.0	71.61	98.36	39.07	SS
2900.	3.932	6	1.5	3.9	10000.0	71.61	101.10	39.34	SS
3000.	3.889	6	1.5	3.9	10000.0	71.61	103.84	39.61	SS
3500.	3.811	6	1.0	2.6	10000.0	78.16	117.38	39.75	SS
4000.	3.731	5	1.0	1.8	10000.0	97.46	179.06	55.43	SS
4500.	3.689	5	1.0	1.8	10000.0	97.46	199.08	58.19	SS
5000.	3.616	5	1.0	1.8	10000.0	97.46	218.86	60.83	SS
5500.	3.523	5	1.0	1.8	10000.0	97.46	238.42	63.36	SS
6000.	3.420	5	1.0	1.8	10000.0	97.46	257.77	65.79	SS
6500.	3.311	5	1.0	1.8	10000.0	97.46	276.94	68.14	SS
7000.	3.199	5	1.0	1.8	10000.0	97.46	295.94	70.42	SS
7500.	3.089	5	1.0	1.8	10000.0	97.46	314.78	72.62	SS
8000.	2.980	5	1.0	1.8	10000.0	97.46	333.47	74.76	SS
8500.	2.904	6	1.0	2.6	10000.0	78.16	244.98	49.39	SS
9000.	2.838	6	1.0	2.6	10000.0	78.16	257.17	50.26	SS
9500.	2.774	6	1.0	2.6	10000.0	78.16	269.29	51.11	SS
10000.	2.711	6	1.0	2.6	10000.0	78.16	281.34	51.94	SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 1. M:
301. 9.534 5 4.0 7.3 10000.0 60.92 25.66 33.25 SS

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

*** SCREEN DISCRETE DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
368.	8.077	6	3.0	7.8	10000.0	61.88	27.68	33.59	SS
376.	7.925	6	3.0	7.8	10000.0	62.09	27.93	33.61	SS
772.	6.197	1	1.0	1.1	320.0	285.43	166.08	262.45	SS
781.	6.203	1	1.0	1.1	320.0	285.43	167.79	268.97	SS
810.	6.168	1	1.0	1.1	320.0	285.43	173.29	290.54	SS

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED

DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** REGULATORY (Default) ***
 PERFORMING CAVITY CALCULATIONS
 WITH ORIGINAL SCREEN CAVITY MODEL
 (BRODE, 1988)

*** CAVITY CALCULATION - 1 ***	*** CAVITY CALCULATION - 2 ***
CONC (UG/M**3) = 443.0	CONC (UG/M**3) = 996.9
CRIT WS @10M (M/S) = 1.00	CRIT WS @10M (M/S) = 1.00
CRIT WS @ HS (M/S) = 1.41	CRIT WS @ HS (M/S) = 1.41
DILUTION WS (M/S) = 1.00	DILUTION WS (M/S) = 1.00
CAVITY HT (M) = 120.61	CAVITY HT (M) = 100.68
CAVITY LENGTH (M) = 95.77	CAVITY LENGTH (M) = 30.84
ALONGWIND DIM (M) = 12.19	ALONGWIND DIM (M) = 27.43

 END OF CAVITY CALCULATIONS

 *** SUMMARY OF SCREEN MODEL RESULTS ***

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
-----	-----	-----	-----
SIMPLE TERRAIN	9.534	301.	0.
BLDG. CAVITY-1	443.0	96.	-- (DIST = CAVITY LENGTH)
BLDG. CAVITY-2	996.9	31.	-- (DIST = CAVITY LENGTH)

 ** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **

09/19/12

16:05:27

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

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SIMPLE TERRAIN INPUTS:

SOURCE TYPE = POINT
EMISSION RATE (G/S) = 1.00000
STACK HEIGHT (M) = 30.4800
STK INSIDE DIAM (M) = 1.0670
STK EXIT VELOCITY (M/S) = 5.4400
STK GAS EXIT TEMP (K) = 699.8170
AMBIENT AIR TEMP (K) = 293.0000
RECEPTOR HEIGHT (M) = 0.0000
URBAN/RURAL OPTION = RURAL
BUILDING HEIGHT (M) = 40.5000
MIN HORIZ BLDG DIM (M) = 5.5000
MAX HORIZ BLDG DIM (M) = 5.5000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

BUOY. FLUX = 8.826 M**4/S**3; MOM. FLUX = 3.527 M**4/S**2.

*** FULL METEOROLOGY ***

*** SCREEN AUTOMATED DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
1.	0.000	0	0.0	0.0	0.0	0.00	0.00	0.00	NA
100.	4.630	1	3.0	3.2	960.0	39.63	26.85	13.95	SS
200.	15.30	1	3.0	3.2	960.0	50.36	49.97	29.30	SS
300.	17.67	3	5.0	5.6	1600.0	39.05	34.29	23.42	SS
400.	18.31	3	4.5	5.0	1440.0	40.96	44.65	29.47	SS
500.	17.57	3	3.5	3.9	1120.0	46.71	54.77	35.41	SS
600.	16.47	3	3.0	3.4	960.0	51.19	64.71	41.25	SS
700.	15.63	4	4.5	5.3	1440.0	39.91	49.26	27.87	SS
800.	15.24	4	4.0	4.7	1280.0	42.21	55.64	30.53	SS
900.	13.98	4	4.0	4.7	1280.0	42.21	61.95	31.29	SS
1000.	13.52	4	3.5	4.1	1120.0	45.27	68.19	33.51	SS
1100.	12.92	4	3.5	4.1	1120.0	45.27	74.38	35.49	SS
1200.	12.43	4	3.0	3.5	960.0	49.48	80.50	37.42	SS
1300.	11.94	4	3.0	3.5	960.0	49.48	86.58	39.29	SS
1400.	11.43	4	3.0	3.5	960.0	49.48	92.62	41.12	SS
1500.	11.03	4	2.5	3.0	800.0	55.49	98.61	42.90	SS

1600.	10.66	4	2.5	3.0	800.0	55.49	104.56	44.64	SS
1700.	10.28	4	2.5	3.0	800.0	55.49	110.47	46.34	SS
1800.	9.890	4	2.5	3.0	800.0	55.49	116.35	48.01	SS
1900.	9.510	4	2.0	2.4	640.0	64.64	122.19	49.65	SS
2000.	9.266	4	2.0	2.4	640.0	64.64	128.01	51.26	SS
2100.	9.013	4	2.0	2.4	640.0	64.64	133.79	52.84	SS
2200.	8.755	4	2.0	2.4	640.0	64.64	139.54	54.40	SS
2300.	8.748	5	1.0	1.5	10000.0	70.89	109.94	37.48	SS
2400.	8.918	5	1.0	1.5	10000.0	70.89	114.20	38.36	SS
2500.	9.055	5	1.0	1.5	10000.0	70.89	118.45	39.21	SS
2600.	9.162	5	1.0	1.5	10000.0	70.89	122.67	40.06	SS
2700.	9.242	5	1.0	1.5	10000.0	70.89	126.88	40.89	SS
2800.	9.298	5	1.0	1.5	10000.0	70.89	131.08	41.71	SS
2900.	9.333	5	1.0	1.5	10000.0	70.89	135.25	42.51	SS
3000.	9.349	5	1.0	1.5	10000.0	70.89	139.42	43.31	SS
3500.	9.220	5	1.0	1.5	10000.0	70.89	160.02	47.13	SS
4000.	8.784	5	1.0	1.5	10000.0	70.89	180.30	50.19	SS
4500.	8.326	5	1.0	1.5	10000.0	70.89	200.31	53.22	SS
5000.	8.049	6	1.0	1.8	10000.0	58.89	148.05	34.92	SS
5500.	7.962	6	1.0	1.8	10000.0	58.89	161.05	36.44	SS
6000.	7.820	6	1.0	1.8	10000.0	58.89	173.91	37.88	SS
6500.	7.643	6	1.0	1.8	10000.0	58.89	186.65	39.27	SS
7000.	7.385	6	1.0	1.8	10000.0	58.89	199.28	40.31	SS
7500.	7.162	6	1.0	1.8	10000.0	58.89	211.81	41.46	SS
8000.	6.939	6	1.0	1.8	10000.0	58.89	224.24	42.57	SS
8500.	6.720	6	1.0	1.8	10000.0	58.89	236.58	43.64	SS
9000.	6.506	6	1.0	1.8	10000.0	58.89	248.83	44.67	SS
9500.	6.300	6	1.0	1.8	10000.0	58.89	261.00	45.67	SS
10000.	6.101	6	1.0	1.8	10000.0	58.89	273.10	46.64	SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 1. M:
 376. 18.40 3 4.5 5.0 1440.0 40.96 42.29 28.09
 SS

DWASH= MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** SCREEN DISCRETE DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
 DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
409.	18.27	3	4.0	4.5	1280.0	43.43	45.57	30.01	SS
772.	15.37	4	4.0	4.7	1280.0	42.21	53.86	29.79	SS
781.	15.33	4	4.0	4.7	1280.0	42.21	54.43	30.03	SS
810.	15.18	4	4.0	4.7	1280.0	42.21	56.27	30.79	SS

DWASH= MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED

DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** REGULATORY (Default) ***
 PERFORMING CAVITY CALCULATIONS
 WITH ORIGINAL SCREEN CAVITY MODEL
 (BRODE, 1988)

*** CAVITY CALCULATION - 1 ***	*** CAVITY CALCULATION - 2 ***
CONC (UG/M**3) = 2993.	CONC (UG/M**3) = 2993.
CRIT WS @10M (M/S) = 1.00	CRIT WS @10M (M/S) = 1.00
CRIT WS @ HS (M/S) = 1.25	CRIT WS @ HS (M/S) = 1.25
DILUTION WS (M/S) = 1.00	DILUTION WS (M/S) = 1.00
CAVITY HT (M) = 94.81	CAVITY HT (M) = 94.81
CAVITY LENGTH (M) = 26.97	CAVITY LENGTH (M) = 26.97
ALONGWIND DIM (M) = 5.50	ALONGWIND DIM (M) = 5.50

 END OF CAVITY CALCULATIONS

 *** SUMMARY OF SCREEN MODEL RESULTS ***

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
-----	-----	-----	-----
SIMPLE TERRAIN	18.40	376.	0.
BLDG. CAVITY-1	2993.	27.	-- (DIST = CAVITY LENGTH)
BLDG. CAVITY-2	2993.	27.	-- (DIST = CAVITY LENGTH)

 ** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **

09/19/12

16:06:26

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

C:\Lakes\Screen View\Boilers.scr

SIMPLE TERRAIN INPUTS:

SOURCE TYPE = POINT
EMISSION RATE (G/S) = 1.00000
STACK HEIGHT (M) = 30.7800
STK INSIDE DIAM (M) = 1.9050
STK EXIT VELOCITY (M/S) = 17.3860
STK GAS EXIT TEMP (K) = 427.5940
AMBIENT AIR TEMP (K) = 293.0000
RECEPTOR HEIGHT (M) = 0.0000
URBAN/RURAL OPTION = RURAL
BUILDING HEIGHT (M) = 54.8600
MIN HORIZ BLDG DIM (M) = 12.1900
MAX HORIZ BLDG DIM (M) = 27.4300

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

BUOY. FLUX = 48.688 M**4/S**3; MOM. FLUX = 187.917 M**4/S**2.

*** FULL METEOROLOGY ***

*** SCREEN AUTOMATED DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
1.	0.000	0	0.0	0.0	0.0	0.00	0.00	0.00	NA
100.	91.44	6	2.0	3.7	10000.0	35.67	11.17	21.68	SS
200.	50.23	4	4.0	4.7	1280.0	39.53	17.87	28.38	SS
300.	37.81	6	2.0	3.7	10000.0	48.80	24.57	35.08	SS
400.	33.38	6	2.0	3.7	10000.0	48.80	28.69	36.32	SS
500.	30.29	6	2.0	3.7	10000.0	48.80	31.82	36.61	SS
600.	27.77	6	2.0	3.7	10000.0	48.80	34.91	36.91	SS
700.	25.67	6	2.0	3.7	10000.0	48.80	37.98	37.20	SS
800.	23.90	6	2.0	3.7	10000.0	48.80	41.03	37.48	SS
900.	22.37	6	2.0	3.7	10000.0	48.80	44.05	37.77	SS
1000.	21.05	6	2.0	3.7	10000.0	48.80	47.04	38.05	SS
1100.	19.89	6	2.0	3.7	10000.0	48.80	50.02	38.33	SS
1200.	18.86	6	2.0	3.7	10000.0	48.80	52.98	38.61	SS
1300.	17.95	6	2.0	3.7	10000.0	48.80	55.92	38.88	SS
1400.	17.12	6	2.0	3.7	10000.0	48.80	58.84	39.16	SS
1500.	16.43	6	1.5	2.8	10000.0	55.17	61.75	36.94	SS

1600.	15.85	6	1.5	2.8	10000.0	55.17	64.64	37.23	SS
1700.	15.31	6	1.5	2.8	10000.0	55.17	67.52	37.52	SS
1800.	14.81	6	1.5	2.8	10000.0	55.17	70.38	37.80	SS
1900.	14.36	6	1.5	2.8	10000.0	55.17	73.23	38.08	SS
2000.	13.93	6	1.5	2.8	10000.0	55.17	76.06	38.36	SS
2100.	13.53	6	1.5	2.8	10000.0	55.17	78.89	38.64	SS
2200.	13.16	6	1.5	2.8	10000.0	55.17	81.70	38.92	SS
2300.	12.82	6	1.5	2.8	10000.0	55.17	84.50	39.19	SS
2400.	12.49	6	1.5	2.8	10000.0	55.17	87.30	39.46	SS
2500.	12.18	6	1.5	2.8	10000.0	55.17	90.08	39.73	SS
2600.	11.89	6	1.5	2.8	10000.0	55.17	92.85	39.99	SS
2700.	11.46	6	1.5	2.8	10000.0	55.17	95.61	39.67	SS
2800.	11.21	6	1.5	2.8	10000.0	55.17	98.36	39.94	SS
2900.	10.97	6	1.5	2.8	10000.0	55.17	101.10	40.19	SS
3000.	10.73	6	1.5	2.8	10000.0	55.17	103.84	40.42	SS
3500.	9.712	6	1.5	2.8	10000.0	55.17	117.38	41.57	SS
4000.	8.885	6	1.5	2.8	10000.0	55.17	130.74	42.67	SS
4500.	8.377	6	1.0	1.9	10000.0	66.78	132.50	40.99	SS
5000.	7.954	6	1.0	1.9	10000.0	66.78	145.67	42.11	SS
5500.	7.575	6	1.0	1.9	10000.0	66.78	158.69	43.20	SS
6000.	7.233	6	1.0	1.9	10000.0	66.78	171.58	44.24	SS
6500.	6.922	6	1.0	1.9	10000.0	66.78	184.34	45.26	SS
7000.	6.637	6	1.0	1.9	10000.0	66.78	196.99	46.24	SS
7500.	6.374	6	1.0	1.9	10000.0	66.78	209.54	47.19	SS
8000.	6.130	6	1.0	1.9	10000.0	66.78	221.98	48.12	SS
8500.	5.904	6	1.0	1.9	10000.0	66.78	234.34	49.02	SS
9000.	5.693	6	1.0	1.9	10000.0	66.78	246.61	49.90	SS
9500.	5.495	6	1.0	1.9	10000.0	66.78	258.79	50.76	SS
10000.	5.311	6	1.0	1.9	10000.0	66.78	270.90	51.60	SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 1. M:
91. 97.79 5 2.5 3.7 10000.0 35.00 10.64 21.14

SS

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

*** SCREEN DISCRETE DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
440.	32.06	6	2.0	3.7	10000.0	48.80	29.94	36.44	SS
772.	24.37	6	2.0	3.7	10000.0	48.80	40.18	37.40	SS
781.	24.21	6	2.0	3.7	10000.0	48.80	40.45	37.43	SS
810.	23.74	6	2.0	3.7	10000.0	48.80	41.33	37.51	SS

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED

DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** REGULATORY (Default) ***
 PERFORMING CAVITY CALCULATIONS
 WITH ORIGINAL SCREEN CAVITY MODEL
 (BRODE, 1988)

*** CAVITY CALCULATION - 1 ***	*** CAVITY CALCULATION - 2 ***
CONC (UG/M**3) = 443.0	CONC (UG/M**3) = 996.9
CRIT WS @10M (M/S) = 1.00	CRIT WS @10M (M/S) = 1.00
CRIT WS @ HS (M/S) = 1.25	CRIT WS @ HS (M/S) = 1.25
DILUTION WS (M/S) = 1.00	DILUTION WS (M/S) = 1.00
CAVITY HT (M) = 120.61	CAVITY HT (M) = 100.68
CAVITY LENGTH (M) = 95.77	CAVITY LENGTH (M) = 30.84
ALONGWIND DIM (M) = 12.19	ALONGWIND DIM (M) = 27.43

 END OF CAVITY CALCULATIONS

 *** SUMMARY OF SCREEN MODEL RESULTS ***

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
-----	-----	-----	-----
SIMPLE TERRAIN	97.79	91.	0.
BLDG. CAVITY-1	443.0	96.	-- (DIST = CAVITY LENGTH)
BLDG. CAVITY-2	996.9	31.	-- (DIST = CAVITY LENGTH)

 ** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **

09/20/12
16:45:20

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

C:\Lakes\Screen View\SRUs.scr

SIMPLE TERRAIN INPUTS:

SOURCE TYPE = POINT
EMISSION RATE (G/S) = 1.00000
STACK HEIGHT (M) = 65.0000
STK INSIDE DIAM (M) = 1.0670
STK EXIT VELOCITY (M/S) = 16.8490
STK GAS EXIT TEMP (K) = 810.9280
AMBIENT AIR TEMP (K) = 293.0000
RECEPTOR HEIGHT (M) = 0.0000
URBAN/RURAL OPTION = RURAL
BUILDING HEIGHT (M) = 0.0000
MIN HORIZ BLDG DIM (M) = 0.0000
MAX HORIZ BLDG DIM (M) = 0.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

STACK EXIT VELOCITY WAS CALCULATED FROM
VOLUME FLOW RATE = 15.065822 (M**3/S)

BOUY. FLUX = 30.035 M**4/S**3; MOM. FLUX = 29.195 M**4/S**2.

*** FULL METEOROLOGY ***

*** SCREEN AUTOMATED DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
1.	0.000	1	1.0	1.1	320.0	306.12	2.18	2.15	NO
100.	0.7962E-13	5	1.0	1.9	10000.0	139.27	17.04	16.29	NO
200.	0.2590E-02	1	3.0	3.4	960.0	145.37	51.95	32.57	NO
300.	0.4214	1	3.0	3.4	960.0	145.37	74.14	50.96	NO
400.	1.962	1	3.0	3.4	960.0	145.37	95.42	74.65	NO
500.	3.000	1	3.0	3.4	960.0	145.37	115.35	107.14	NO
600.	3.689	1	1.0	1.1	320.0	306.12	149.67	168.65	NO
700.	5.392	1	1.0	1.1	320.0	306.12	167.16	224.18	NO
800.	5.724	1	1.0	1.1	320.0	306.12	184.72	291.27	NO
900.	5.392	1	1.0	1.1	320.0	306.12	202.28	369.61	NO
1000.	4.975	1	1.0	1.1	320.0	306.12	219.78	459.05	NO
1100.	4.610	1	1.0	1.1	320.0	306.12	237.22	559.55	NO
1200.	4.296	1	1.0	1.1	320.0	306.12	254.56	671.13	NO
1300.	4.023	1	1.0	1.1	320.0	306.12	271.81	793.83	NO
1400.	3.785	1	1.0	1.1	320.0	306.12	288.96	927.70	NO
1500.	3.574	1	1.0	1.1	320.0	306.12	306.01	1072.81	NO

1600.	3.386	1	1.0	1.1	320.0	306.12	322.95	1229.24	NO
1700.	3.218	1	1.0	1.1	320.0	306.12	339.80	1397.04	NO
1800.	3.271	2	1.0	1.1	320.0	306.12	269.23	219.39	NO
1900.	3.302	2	1.0	1.1	320.0	306.12	281.63	231.51	NO
2000.	3.299	2	1.0	1.1	320.0	306.12	293.98	243.76	NO
2100.	3.271	2	1.0	1.1	320.0	306.12	306.29	256.12	NO
2200.	3.223	2	1.0	1.1	320.0	306.12	318.55	268.58	NO
2300.	3.161	2	1.0	1.1	320.0	306.12	330.76	281.14	NO
2400.	3.090	2	1.0	1.1	320.0	306.12	342.93	293.79	NO
2500.	3.014	2	1.0	1.1	320.0	306.12	355.05	306.52	NO
2600.	2.936	2	1.0	1.1	320.0	306.12	367.12	319.33	NO
2700.	2.856	2	1.0	1.1	320.0	306.12	379.15	332.21	NO
2800.	2.778	2	1.0	1.1	320.0	306.12	391.13	345.16	NO
2900.	2.702	2	1.0	1.1	320.0	306.12	403.08	358.18	NO
3000.	2.629	2	1.0	1.1	320.0	306.12	414.98	371.26	NO
3500.	2.326	3	1.0	1.2	320.0	292.96	327.11	203.02	NO
4000.	2.360	3	1.0	1.2	320.0	292.96	367.29	226.83	NO
4500.	2.302	3	1.0	1.2	320.0	292.96	407.05	250.60	NO
5000.	2.197	3	1.0	1.2	320.0	292.96	446.41	274.31	NO
5500.	2.073	3	1.0	1.2	320.0	292.96	485.40	297.95	NO
6000.	1.947	3	1.0	1.2	320.0	292.96	524.04	321.49	NO
6500.	1.827	3	1.0	1.2	320.0	292.96	562.35	344.94	NO
7000.	1.717	3	1.0	1.2	320.0	292.96	600.35	368.30	NO
7500.	1.618	3	1.0	1.2	320.0	292.96	638.06	391.56	NO
8000.	1.530	3	1.0	1.2	320.0	292.96	675.49	414.73	NO
8500.	1.450	3	1.0	1.2	320.0	292.96	712.66	437.81	NO
9000.	1.379	3	1.0	1.2	320.0	292.96	749.57	460.80	NO
9500.	1.315	3	1.0	1.2	320.0	292.96	786.26	483.70	NO
10000.	1.257	3	1.0	1.2	320.0	292.96	822.71	506.53	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 1. M:

780.	5.738	1	1.0	1.1	320.0	306.12	181.39	277.65	NO
------	-------	---	-----	-----	-------	--------	--------	--------	----

DWASH= MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** SCREEN DISCRETE DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
376.	1.599	1	3.0	3.4	960.0	145.37	90.38	68.72	NO
440.	2.559	1	3.0	3.4	960.0	145.37	103.49	86.99	NO
772.	5.735	1	1.0	1.1	320.0	306.12	179.80	271.34	NO
810.	5.706	1	1.0	1.1	320.0	306.12	186.48	298.60	NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED

DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

*** SUMMARY OF SCREEN MODEL RESULTS ***

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
SIMPLE TERRAIN	5.738	780.	0.

** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **

10/17/12

13:57:57

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

C:\Lakes\Screen View\Coker 3 drum.scr

SIMPLE TERRAIN INPUTS:

SOURCE TYPE = VOLUME
EMISSION RATE (G/S) = 0.518000E-01
SOURCE HEIGHT (M) = 0.0000
INIT. LATERAL DIMEN (M) = 6.8048
INIT. VERTICAL DIMEN (M) = 0.8510
RECEPTOR HEIGHT (M) = 0.0000
URBAN/RURAL OPTION = RURAL

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

BUOY. FLUX = 0.000 M**4/S**3; MOM. FLUX = 0.000 M**4/S**2.

*** FULL METEOROLOGY ***

*** SCREEN AUTOMATED DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING
DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
0.000	0	0.0	0.0	0.0	0.00	0.00	0.00		-1.
100.	556.7	6	1.0	1.0	10000.0	0.00	10.34	2.87	NO
200.	265.0	6	1.0	1.0	10000.0	0.00	13.76	4.52	NO
300.	160.1	6	1.0	1.0	10000.0	0.00	17.11	6.02	NO
400.	109.0	6	1.0	1.0	10000.0	0.00	20.40	7.42	NO
500.	79.77	6	1.0	1.0	10000.0	0.00	23.63	8.75	NO
600.	61.33	6	1.0	1.0	10000.0	0.00	26.82	10.03	NO
700.	49.53	6	1.0	1.0	10000.0	0.00	29.97	11.11	NO
800.	41.03	6	1.0	1.0	10000.0	0.00	33.08	12.15	NO
900.	34.67	6	1.0	1.0	10000.0	0.00	36.17	13.15	NO
1000.	29.90	6	1.0	1.0	10000.0	0.00	39.23	14.06	NO
1100.	26.15	6	1.0	1.0	10000.0	0.00	42.26	14.92	NO
1200.	23.11	6	1.0	1.0	10000.0	0.00	45.27	15.76	NO
1300.	20.62	6	1.0	1.0	10000.0	0.00	48.26	16.57	NO
1400.	18.55	6	1.0	1.0	10000.0	0.00	51.23	17.35	NO
1500.	16.79	6	1.0	1.0	10000.0	0.00	54.18	18.12	NO
1600.	15.30	6	1.0	1.0	10000.0	0.00	57.11	18.87	NO
1700.	14.01	6	1.0	1.0	10000.0	0.00	60.03	19.60	NO
1800.	12.90	6	1.0	1.0	10000.0	0.00	62.93	20.32	NO
1900.	11.92	6	1.0	1.0	10000.0	0.00	65.81	21.02	NO
2000.	11.08	6	1.0	1.0	10000.0	0.00	68.68	21.66	NO

2100.	10.36	6	1.0	1.0	10000.0	0.00	71.54	22.24	NO
2200.	9.718	6	1.0	1.0	10000.0	0.00	74.39	22.81	NO
2300.	9.138	6	1.0	1.0	10000.0	0.00	77.22	23.37	NO
2400.	8.614	6	1.0	1.0	10000.0	0.00	80.04	23.92	NO
2500.	8.139	6	1.0	1.0	10000.0	0.00	82.85	24.45	NO
2600.	7.707	6	1.0	1.0	10000.0	0.00	85.64	24.98	NO
2700.	7.313	6	1.0	1.0	10000.0	0.00	88.43	25.50	NO
2800.	6.951	6	1.0	1.0	10000.0	0.00	91.21	26.01	NO
2900.	6.619	6	1.0	1.0	10000.0	0.00	93.97	26.51	NO
3000.	6.317	6	1.0	1.0	10000.0	0.00	96.73	26.98	NO
3500.	5.153	6	1.0	1.0	10000.0	0.00	110.38	28.99	NO
4000.	4.317	6	1.0	1.0	10000.0	0.00	123.83	30.84	NO
4500.	3.691	6	1.0	1.0	10000.0	0.00	137.11	32.58	NO
5000.	3.208	6	1.0	1.0	10000.0	0.00	150.22	34.21	NO
5500.	2.825	6	1.0	1.0	10000.0	0.00	163.19	35.76	NO
6000.	2.515	6	1.0	1.0	10000.0	0.00	176.04	37.24	NO
6500.	2.260	6	1.0	1.0	10000.0	0.00	188.76	38.65	NO
7000.	2.047	6	1.0	1.0	10000.0	0.00	201.37	40.00	NO
7500.	1.873	6	1.0	1.0	10000.0	0.00	213.88	41.16	NO
8000.	1.723	6	1.0	1.0	10000.0	0.00	226.30	42.28	NO
8500.	1.594	6	1.0	1.0	10000.0	0.00	238.62	43.36	NO
9000.	1.480	6	1.0	1.0	10000.0	0.00	250.86	44.40	NO
9500.	1.381	6	1.0	1.0	10000.0	0.00	263.02	45.41	NO
10000.	1.292	6	1.0	1.0	10000.0	0.00	275.10	46.39	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 1. M:
 16. 1839. 6 1.0 1.0 10000.0 0.00 7.41 1.24 NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** SCREEN DISCRETE DISTANCES ***

** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
368.	122.1	6	1.0	1.0	10000.0	0.00	19.35	6.98	NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** SUMMARY OF SCREEN MODEL RESULTS ***

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
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----- ----- ----- -----
SIMPLE TERRAIN 1839. 16. 0.

** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS

Screen3 Model Inputs

	New Crude 1 Heater (A)	New Crude 1 Heater (B)	New Vac 1 Heater	Coker 3 Heater	ADHT Heater	Steam Boilers	SRU 1	SRU 2&3
Emission Rate (g/s)	1	1	1	1	1	1	1	1
Stack Height (m)*	82.296	82.296	70.104	56.388	30.48	30.78	69.49	53.34
Stack Diameter (m)	2.4384	2.4384	1.8288	1.905	1.067	1.905	1.067	1.524
Exit Velocity (m/s)	6.747	6.747	7.935	5.944	5.44	17.386	16.849	16.764
Exit Temperature (K)	449.8167	449.8167	449.8167	755.372	699.817	427.594	810.928	922.039
Exit Temperature (R)	809.67	809.67	809.67	1359.67	1259.671	769.6692	1459.67	1659.67
Distance to Fence line (m)	554	554	554	368	409	440	259	266

Volume Source	Coker 3 Drum
Emission Rate (g/s)	0.0518
Release Height (m)	0
Initial Lateral Dimension (m)	6.8048
Initial Vertical Dimension (m)	0.851
Distance to Fence line (m)	368

Downwash

BUILDING HEIGHT (M)	36.58	36.58	36.58	54.86	40.5	54.86	NA	NA
MIN HORIZ BLDG DIM (M)	5.49	5.49	5.49	12.19	5.5	12.19	NA	NA
MAX HORIZ BLDG DIM (M)	5.49	5.49	5.49	27.43	5.5	27.43	NA	NA
GEP Height	44.82	44.82	44.82	73.15	48.75	73.15		
	(Coker 3 bubble tower)	(Coker 3 bubble tower)	(Coker 3 bubble tower)	Coker 3 structure	Crude Tower	Coker 3 structure		

Notes:

When running model, assume no stack height over 65 meters
 estimated velocity by $V = nRT/P$; ($R = 10.73 \text{ ft}^3 \cdot \text{psia}/\text{lb-mol} \cdot \text{R}$), $P = 14.1 \text{ psia}$
 Assume all emissions from Crude Heaters emit through only one stack
 Assume SRU1 and SRU 2&3 emit through the worst-case stack (SRU1)

*Downwash structures determined by using info from BPIP file

Additional Parameter Assumptions:

- Rural
- Full meteorology
- Simple/Flat Terrain
- Including downwash

Note: The Coke Pit is 96 x 133 ft

Used 96 ft for the side of the source for conservatism

*Initial Vertical Dimension estimated based on

half the assumed wall heights of the pit (7 ft)

TFO Project Emission Increases

Pollutant (tons/yr)	New Crude Heaters	New Vac 1 Heater	Coker 3 Heater	ADHT Heater	Steam Boilers	SRU 1 & SRU 2&3	Coker 3 Pit
H ₂ S	NA	NA	NA	NA	NA	NA	1.80
SO ₂	15.61	5.20	-11.88	0.51	2.13	47.18	NA

Pollutant (lb/hr)	New Crude Heaters	New Vac 1 Heater	Coker 3 Heater	ADHT Heater	Steam Boilers	SRU 1 & SRU 2&3
SO ₂	8.25	2.75	NA	0.53	5.02	NA

*lb/hr SO₂ emissions are based on maximum firing rates and 162 ppm H₂S for a maximum short-term worst-case
 These emissions were used for the 24-hr and 3-hr SO₂ modeling analysis

Pollutant (g/s)	New Crude Heaters	New Vac 1 Heater	Coker 3 Heater	ADHT Heater	Steam Boilers	SRU 1 & SRU 2&3	Coker 3 Pit
H ₂ S	NA	NA	NA	NA	NA	NA	0.052
SO ₂ (annual)	4.49E-01	1.50E-01	-3.42E-01	1.48E-02	6.14E-02	1.36	NA
SO ₂ (24hr/ 3hr)	1.04	0.35	NA	0.07	0.63	NA	NA

Screen3 Modeling Analysis

Maximum Predicted 1-hr Average Concentration

Pollutant (µg/m³)	New Crude Heaters	New Vac 1 Heater	ADHT Heater	Steam Boilers	SRU 1, SRU 2&3	Coker 3 Pit	Total
H ₂ S	NA	NA	NA	NA	NA	111.80	111.80
SO ₂ (annual)	5.38	2.17	0.27	1.97	7.75	NA	17.54
SO ₂ (short term)	14.46	5.34	1.22	20.29	7.75	NA	49.07

Notes:

- Concentration is the maximum concentration past the fence line for each stack
- Short-term emissions modeled are based on 162 ppm H₂S

Screen3 1-hr Average Conversation Factors

Converting to	Multiply by
3-hr	0.9
24-hr	0.4
Annual	0.08

Calculation for MAGLC

$$\text{MAGLC} = \frac{\text{TLV}}{10} \times \frac{8 \text{ hours}}{24 \text{ hours}} \times \frac{5 \text{ days}}{7 \text{ days}} = \frac{\text{TLV}}{42}$$

H₂S: TLV = 10 ppm, M.W. = 34.05 lb/lbmole

Modeled Results Compared to Ohio EPA Thresholds

Pollutant	Averaging Period	Ohio Acceptable Incremental Impact ¹ (ug/m³)	Maximum Predicted Concentration (ug/m³)
SO ₂	Annual	10	1.40
	24-hr	45.5	19.63
	3-hr	256	44.16

Air Toxic Modeled Results

Air Toxic	Ohio MAGLC (Annual) (ug/m³)	Maximum Predicted Concentration (ug/m³)
H ₂ S	331.58	111.80

Notes:

1 - Established in Ohio's Engineering Guide #69

Notes:

- PPM converts to ug/m3 by multiplying ppm by the compound molecular weight (g/gmole), dividing by 24.45 liters/gmole, times 1000 (liters/m3)

Appendix C

BAT Cost Calculations

Appendix C
BAT Cost Calculations

BP Toledo - SCR Cost Analysis (Crude 1 furnace 450 mmbtu/hr total)		
Total Capital Investment		
SCR System for NOx removal from 40 ppm to 4 ppm		
Item	Basis	Cost
Direct Costs		
(1) Purchased Equipment		
SCR System	Vendor Quote (adjusted)	\$2,750,722
Ammonia Storage and Pumping	<i>SCR quote for larger furnace has been scaled to TFO furnace using ratio of sizes raised to 0.6 power.</i>	Incl. in above
Initial Catalyst Charge		Incl. in above
(a) Total Equipment		\$2,750,722
(b) Freight (0.05 x [1a])	OAQPS, Sect. 1, Table 2.4	\$137,536
(c) Sales Tax (0.06 x [1a])	OAQPS, Sect. 1, Table 2.4	\$165,043
(d) Instrumentation (0.10 x [1a])	OAQPS, Sect. 1, Table 2.4	\$275,072
Total Purchased Equipment Cost, PEC [1a thru 1d]		\$3,328,374
(2) Direct Installation (0.083 x PEC)	Peters & Timmerhaus, 1991	\$276,255
(3) Instrumentation Controls (installed) (0.02 x PEC)	P & T, 1991	\$66,567
(4) Piping (installed) (0.073 x PEC)	P & T, 1991	\$242,971
(5) Electrical (installed) (0.046 x PEC)	P & T, 1991	\$153,105
TOTAL DIRECT COST (TDC) (1 thru 5)		\$4,067,273
Indirect Costs		
(6) Indirect Installation		
(a) General Facilities (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	\$203,364
(b) Engineering and Home Office Fees (0.10 * TDC)	OAQPS, Sect. 4, Table 2.5	\$406,727
(c) Process Contingency (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	\$203,364
(7) Other Indirect Costs		
(a) Startup & Performance Tests (0.08 x TDC)	P & T, 1991	\$325,382
TOTAL INDIRECT COST (TIC) (6+7)		\$1,138,836
Project Contingency		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	\$780,916
Total Plant Cost (TIC + TDC + Cont.)		\$5,987,026
(9) Preproduction Cost (0.02 * TPC)	OAQPS, Sect. 4, Table 2.5	\$119,741
(10) Initial Chemical Inventory (NH3)	OAQPS, Sect. 4, Table 2.5	
SUMMARY		
TOTAL CAPITAL INVESTMENT (TCI)		\$6,106,767

Appendix C

BAT Cost Calculations

BP Toledo BAT Cost Effectiveness Analysis for SCR (Crude 1)

Unit Characteristics

Crude 1 Heater Firing Rate	MMBtu/hr	=	450
H	= annual operating hours	=	8,760
Catalyst Cost for one charge	URS Estimate		82,212
NO _x removal by SCR control	= tpy NO _x	=	70.96
N (Ammonia requirement, ton/yr)	= (tpy NO _x removed) (MW NH ₃ , 17/ MW NO _x , 46)	=	26.22

Costs

A. Total capital investment, \$	See Separate TCI Spreadsheet	=	\$6,106,767
B. Direct Annual Costs, \$/yr			
1. Operating labor	= (1.0/8 hr shift) x (\$25/hr) x (H)	=	\$27,375
2. Supervisory labor	= (0.15) x (operating labor)	=	\$4,106
3. Maintenance labor and materials	= (0.015 * TCI)	=	\$91,601
4. Catalyst replacement	= Cost x 0.2439 (CRF for 5 yrs, 7%)	=	\$20,051
5. Catalyst disposal		=	\$0
6. Ammonia (anhydrous)	= (N) x (\$425/ ton)	=	\$11,145
7. Natural Gas	= 1% * firing rate * Operating Hrs / 1000 Btu/scf * \$6/Mscf *	=	\$236,520
TOTAL DIRECT COSTS			\$390,799
C. Indirect Annual Costs, \$/yr			
1. Overhead	= (0.6) x (all labor and maintenance material costs)	=	\$73,850
2. Property Taxes, insurance, admin.	= (0.04) x (total capital investment)	=	\$244,271
3. Capital recovery	= (0.1098) x [total capital investment - catalyst replacement cost]	=	\$661,496
TOTAL INDIRECT COSTS			\$979,616
Total Annual cost	= (Direct Annual Costs) + (Indirect Annual Costs)	=	\$1,370,415

Cost Effectiveness

NO _x Emissions from Unit without SCR	= tpy NO _x	=	78.8
NO _x Removal from SCR	= tpy NO _x , 90% of uncontrolled	=	71.0
Cost Effectiveness	\$/tons NO_x	=	\$19,313.59

- The capital recovery factors assumes a 15 year equipment life, catalyst replaced every 5 yrs, and 7% interest.

Appendix C
BAT Cost Calculations

BP Toledo - SCR Cost Analysis (Vacuum 1 Furnace - 150 MMBtu/hr)		
Total Capital Investment		
SCR System for NOx removal from 40 ppm to 4 ppm		
Item	Basis	Cost
Direct Costs		
(1) Purchased Equipment		
SCR System	Vendor Quote (adjusted)	\$1,422,899
Ammonia Storage and Pumping	<i>SCR quote for larger furnace has been scaled to TFO furnace using ratio of sizes raised to 0.6 power.</i>	Incl. in above
Initial Catalyst Charge		Incl. in above
(a) Total Equipment		\$1,422,899
(b) Freight (0.05 x [1a])	OAQPS, Sect. 1, Table 2.4	\$71,145
(c) Sales Tax (0.06 x [1a])	OAQPS, Sect. 1, Table 2.4	\$85,374
(d) Instrumentation (0.10 x [1a])	OAQPS, Sect. 1, Table 2.4	\$142,290
Total Purchased Equipment Cost, PEC [1a thru 1d]		\$1,721,708
(2) Direct Installation (0.083 x PEC)	Peters & Timmerhaus, 1991	\$142,902
(3) Instrumentation Controls (installed) (0.02 x PEC)	P & T, 1991	\$34,434
(4) Piping (installed) (0.073 x PEC)	P & T, 1991	\$125,685
(5) Electrical (installed) (0.046 x PEC)	P & T, 1991	\$79,199
TOTAL DIRECT COST (TDC) (1 thru 5)		\$2,103,927
Indirect Costs		
(6) Indirect Installation		
(a) General Facilities (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	\$105,196
(b) Engineering and Home Office Fees (0.10 * TDC)	OAQPS, Sect. 4, Table 2.5	\$210,393
(c) Process Contingency (0.05 * TDC)	OAQPS, Sect. 4, Table 2.5	\$105,196
(7) Other Indirect Costs		
(a) Startup & Performance Tests (0.08 x TDC)	P & T, 1991	\$168,314
TOTAL INDIRECT COST (TIC) (6+7)		\$589,099
Project Contingency		
(8) Project Contingency ((TDC + TIC) * 0.15)	OAQPS, Sect. 4, Table 2.5	\$403,954
Total Plant Cost (TIC + TDC + Cont.)		\$3,096,980
(9) Preproduction Cost (0.02 * TPC)	OAQPS, Sect. 4, Table 2.5	\$61,940
(10) Initial Chemical Inventory (NH3)	OAQPS, Sect. 4, Table 2.5	
SUMMARY		
TOTAL CAPITAL INVESTMENT (TCI)		\$3,158,920

Appendix C BAT Cost Calculations

BP Toledo BAT Cost Effectiveness Analysis for SCR (Vacuum 1)

Unit Characteristics

Vac 1 Heater Firing Rate	MMBtu/hr	=	150
H	= annual operating hours	=	8,760
Catalyst Cost for one charge	URS Estimate		21,635
NO _x removal by SCR control	= tpy NO _x	=	23.65
N (Ammonia requirement, ton/yr)	= (tpy NO _x removed) (MW NH ₃ , 17/ MW NO _x , 46)	=	8.74

Costs

A. Total capital investment, \$	See Separate TCI Spreadsheet	=	\$3,158,920
B. Direct Annual Costs, \$/yr			
1. Operating labor	= (1.0/8 hr shift) x (\$25/hr) x (H)	=	\$27,375
2. Supervisory labor	= (0.15) x (operating labor)	=	\$4,106
3. Maintenance labor and materials	= (0.015 * TCI)	=	\$47,384
4. Catalyst replacement	= Cost x 0.2439 (CRF for 5 yrs, 7%)	=	\$5,277
5. Catalyst disposal		=	\$0
6. Ammonia (anhydrous)	= (N) x (\$425/ ton)	=	\$3,715
7. Natural Gas	= 1% * firing rate * Operating Hrs / 1000 Btu/scf * \$6/Mscf *	=	\$78,840
TOTAL DIRECT COSTS			\$166,697
C. Indirect Annual Costs, \$/yr			
1. Overhead	= (0.6) x (all labor and maintenance material costs)	=	\$47,319
2. Property Taxes, insurance, admin.	= (0.04) x (total capital investment)	=	\$126,357
3. Capital recovery	= (0.1098) x [total capital investment - catalyst replacement cost]	=	\$344,474
TOTAL INDIRECT COSTS			\$518,150
Total Annual cost	= (Direct Annual Costs) + (Indirect Annual Costs)	=	\$684,846

Cost Effectiveness

NO _x Emissions from Unit without SCR	= tpy NO _x	=	26.3
NO _x Removal from SCR	= tpy NO _x , 90% of uncontrolled	=	23.7
Cost Effectiveness	\$/tons NO_x	=	\$28,955.11

- The capital recovery factors assumes a 15 year equipment life, catalyst replaced every 5 yrs, and 7% interest.

Appendix D

New Source Review Issues for Project Aggregation

Appendix D

New Source Review Issues for Project Aggregation

D.1 TFO Project Aggregation Analysis

The potential applicability of Federal permitting (PSD or non-attainment NSR) depends upon the magnitude of any project emissions; therefore, it is important that this determination consider all project emissions. The first step of the PSD applicability review is to evaluate the emissions increases of the current project. (*Note: this determination is separate from the consideration of contemporaneous projects in the PSD “netting” analysis which is the second step of the evaluation process that is only needed if project increases in the first step are significant.*) In considering the emissions increases of a project, it is important that appropriate consideration is given to situations where multiple projects may be developed and permitted during a similar period of time. Separate projects should be permitted separately and their emissions do not need to be “aggregated” for PSD applicability determination purposes. However, projects occurring in a similar time frame and which depend upon one another for their economic and or technical viability should normally be permitted as a single project. In such a case, their emissions would be “aggregated” in the first step of the PSD applicability review.

In consideration of this issue, BPH has evaluated recent past and potential future projects to verify that EPA’s guidance on aggregation has been appropriately considered for the proposed TFO project. The following sections of this appendix present the evaluation and discuss other BPH Toledo projects that have been recently permitted or may be considered for the future. For each project, an explanation is provided discussing why that project has been determined to be a separate project and not appropriate for aggregation with the scope of the current TFO project.

D.2 US EPA Aggregation Guidance

Neither the Clean Air Act (CAA) nor EPA’s current rules explicitly describe when aggregate is required. At issue is what must be treated as single physical or operational change under the CAA definition of “modification”. In general, aggregation is required when nominally separate changes or projects can collectively be seen as one change.

EPA has advanced arguably inconsistent iterations of its aggregation policies over the years. EPA’s guidance has historically been articulated in a series of guidance memoranda addressing specific projects over the years. Additionally, on January 14, 2009, EPA finalized changes to NSR regulations which directly addressed aggregation issues and were represented by US EPA as clarification of their long standing aggregation policy, not a change in policy. However, this new EPA rule never became effective. EPA stayed the rule “until the proceeding for judicial review of this rule is completed or EPA completes the reconsideration of the rule.” Subsequently, US EPA announced on April 15, 2010 their intention to revoke the 2009 rule, and indicated they believed it would be appropriate to go back to performing case-by-case aggregation analysis outlined in the Maplewood¹ guidance to determine if multiple separate projects “are sufficiently related to fit within one of the ordinary meanings of a single physical change.” 75 Fed. Reg

¹ August 3, 1996 letter from John Rasnic at US EPA to George Czerniak at USEAP addressing applicability of NSR to 3M in Maplewood, Minnesota.

19567, 19571 (April 15, 2010). This is the last substantive position that USEPA has published on the aggregation issue. This recent EPA's Federal Register notice along with the Maplewood guidance and other EPA guidance on the issue of aggregation outlines that aggregation decisions should consider the following issues:

- How close is the timing of multiple projects?
- Are projects economically and/or technically dependent on each other?
- How related are the projects' scopes (do they contribute to the same overall production goals?)
- Are projects funded or managed together or separately?
- Do later projects involve "relaxing" or removing permit conditions from earlier projects?

BPH used the above criteria to review the relationship, or lack thereof, of the current proposed TFO project to other BPH Toledo Refinery projects that have occurred in the recent past or are contemplated in the near future.

D.3 Current Project Scope

The TFO Project allows flexibility to substitute BPH's own Sunrise Canadian crude or other somewhat more corrosive crude oil feedstocks for the Canadian crude oils being processed today. The project will not increase the refinery's overall crude capacity, but it will simply enable the refinery to increase the amount of more corrosive crudes relative to what is currently being processed at the BPH Toledo Refinery. The design basis of this project will accommodate the first tranche (approximately 80 kbpd) of oil-sands-derived Sunrise crude oil expected to become available from the new Alberta Canada "Sunrise" field in the 2014/2015 timeframe. As described in Section 1 of this permit application, The TFO project scope includes changes to allow processing this crude at the BPH Toledo refinery including metallurgical upgrades to the Crude and Vacuum 1 process unit (P011) and replacement furnaces for the existing unit heaters. The project will also debottleneck the existing Coker 3 process unit to accommodate the higher residual oil content and improve the light ends recovery and reduced total sulfur compounds in the fuel gas that is combusted in the refinery. The project may marginally increase diesel production, but should not otherwise impact other product or unit feed rates.

D.4 Recent Past Permits

The following paragraphs include brief descriptions of permits issued to the BPH Toledo Refinery in the last 12-18 months, which is the period of focus for aggregation reviews identified by EPA in the Maplewood guidance.

D.4.1 PTI P0108950 – BGOT Recycle Gas Compressor Project (PTI issued 5-4-12, startup expected in 2013)

This permit was received for the installation of a new recycle compressor in the B-Gas Oil Hydrotreater (BGOT) process unit (B029). This compressor will function as a replacement for the existing compressor in the BGOT unit. The new compressor will be larger than the existing compressor and allow for more compression of recycled gas, which will improve the hydrotreating effectiveness of the unit. This will

allow the unit to either run longer between catalyst change outs or to run approximately 10% higher feed rates at the same catalyst change-out frequency.

Although this project will not physically change the FCCU unit (P007), this project could allow FCCU feed rates to increase marginally above rates experienced in the past couple of years, but not above levels previously achieved in the baseline period (2004-2005). Since 2006, new fuel standards requiring lower sulfur in gasoline have functionally required all of Toledo's FCCU feed to be hydrotreated in the BGOT unit. As such, the FCCU, which has a design capacity of 55 KB/D, has not operated above the current BGOT capacity of about 48 thousand barrels per day (KB/D) since this time. Since the installation of the new compressor will increase BGOT rates approximately 4 to 5 KB/D on average, it will allow a similar feed rate increase to the FCCU unit vs. recent levels. Therefore, the BGOT RGC project will, in effect, merely restore the FCCU rates to levels close to those achieved in practice the pre-2006 operating period.

The BGOT RGC project and the TFO project have entirely different purposes. The BGOT RGC project is a capacity restoration project for the FCCU, returning it to pre-2006 feed rates. In contrast, the TFO project is being performed to enable processing "Sunrise" crude, which does not contain more FCCU feed and will not affect FCCU feed rates. Similarly, the technical and economic merits of the projects are independent. The BGOT project economics derive from higher FCCU rates and gasoline production vs. recent levels. The TFO project economics come from enabling use of less expensive crudes and providing an outlet for the Husky Sunrise field crude (*Note. The Sunrise oil field, along with the Toledo refinery, is owned and operated by a joint venture of BP and Husky Oil.*) Likewise, the two projects have been conceived, are being funded, and are being managed as completely separate projects by BPH. Lastly, their relative timing also separates the two projects. The BGOT RGC project has been permitted, and will be started up, more than a year ahead of the TFO project. For all these economic, technical and timing reasons, the BGOT RGC project is considered a separate project from the TFO project and need not be aggregated.

D.4.2 PTI P0108887 - FCCU Preheat Exchanger

(PTI issued 5/4/2012, startup expected in late 2012)

This project is to replace the existing gas-fired FCC Preheater furnace (B018) with new shell and tube heat exchangers which will heat the FCC Feed using heat from the existing FCC Slurry Reflux stream. BPH is planning to install this equipment because the FCC Preheater furnace (B018) is of 1960's vintage and is at the end of its life. The existing Preheater furnace will be taken out of service, and the new heat exchangers placed in service, during the refinery's fall 2012 Turnaround. This project merely replaces the function of an old furnace. It is not related to the TFO project and its need and justification are unrelated to the TFO project. Further, the timing of these projects are separated by more than one year, which is further indication that these projects should not be aggregated.

D.4.3 PTI 0110265 - CV1 Offgas Rerouting

(PTI issued 8/22/12, startup expected Fall 2012.)

Originally, the Vacuum 1 off-gas stream from the Crude and Vacuum 1 process unit is amine treated and burned as supplemental fuel gas to the Crude 1 heater (B015). This permit allows BPH to route this off-gas stream into the main refinery fuel gas system for amine treatment and subsequent use as fuel in the refinery. This change will result in energy savings by not having to operate the separate amine treater for this off-gas stream. The modified operation is also simpler and expected to be more reliable. This project is not

related to the TFO project and its need and justification is unrelated. Further, these projects are separated by more than one year. This project is not appropriate for aggregation with the TFO project.

D.4.4 PTI P0106190 - Roof Modification of Tank T084

(PTI Issued 6/24/2012, startup in April 2011)

This permit is for the modification of the existing Tank T084 (PR-500134) to upgrade the tank's level monitoring system by installing radar gauges. This 71,166-barrel external floating roof tank is used for the storage of various light hydrocarbons, including naphtha, reformate, and gasoline. Installation of new tank roof fittings triggers NSPS Kb for this previously grandfathered tank. This project will not change the size or service of this tank and has no relationship to, or synergy with, the TFO project.

D.5 Possible Future Permits

The following are brief descriptions of possible future projects and a brief explanation describing why each is not related to the current TFO permit application.

D.5.1 Future Tier 3 Gasoline Standard Related Projects

EPA issued new "Tier 2" fuel standards in 2006 and is currently considering further lowering of gasoline sulfur standards. At one point, new "Tier 3" standards were anticipated in 2016. However, new fuel standards are likely to be delayed versus that previous schedule and the ultimate level of future standards are uncertain. If at such time, US EPA does lower the gasoline sulfur standards, BPH Toledo will likely have to implement a project to comply. Such projects are only conceptual at this time. Since much of the sulfur in gasoline comes from gasoline produced by the FCCU, compliance project options could require either pretreatment of the FCCU feed or post-treatment of the FCCU naphtha (gasoline). In either case, the project would be driven by external product specification requirements. Its justification would be independent of the TFO project and it would be considered appropriate for aggregation with the TFO project.

D.5.2 Future Further Heavy Crude Upgrade

The BPH Toledo refinery may desire, at some future time, to pursue projects to enable the processing of additional Canadian crude oils. For example, as mentioned previously, the current TFO project will enable the refinery to process the first tranche of Sunrise crude commercially available around 2014/2015. The timing of a possible second tranche of Sunrise crude is uncertain, but it is not anticipated until at least 2020. If the tranche 2 development proceeds, it could lead to one or more additional projects at the BPH Toledo refinery in the future such as adding additional residual oil destruction or building a new crude unit. Such projects are little more than a concept at this time. Definitive plans have not been developed and timing is uncertain but should be no sooner than 5 years after the TFO project completion. It is far from certain that any such projects will occur at the Toledo refinery and the current TFO project is not technically or economically dependent on any such potential future project. The TFO project has been planned, engineered, evaluated and economically justified as an independent project.

While possible future heavy crude projects might serve similar strategic goals as the TFO project, for the reasons stated above, such future projects cannot reasonably be considered as fitting within the ordinary meaning of a single physical change with the TFO project and need not be aggregated with it.

Appendix E

GHG BACT Analysis

APPENDIX E

Best Available Control Technology (BACT) for GHG

The permitting of the TFO project requires the employment of best available control technology for Greenhouse Gases (GHG). Effective 2011, U.S. EPA's Greenhouse Gas Tailoring Rule¹ requires projects to undergo PSD review for GHG emissions if the project increases GHG emissions by more than 75,000 tons/year CO₂e. This project has the potential to increase GHG emissions by more than this amount. Therefore, GHG BACT applies. This GHG BACT analysis has been prepared consistent with recent US EPA guidance².

E.1 Top-Down BACT Process Background

BACT is defined in the Clean Air Act as *“an emissions limit based on the maximum degree of emissions reduction for each pollutant...which the permitting authority determines, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, is achievable for such facility through the application of production processes and available methods, systems, and techniques...”*.

The traditional BACT analysis involves a “top-down” process evaluating all potentially applicable emission control technologies. Evaluation begins with the top or most potentially effective of these emission control alternatives. If the most stringent control technology is shown to be technically or economically infeasible, or if the energy, environmental or other impacts are severe enough to preclude its use, then it is eliminated from consideration and the next most stringent control technology is similarly evaluated. This process continues until the BACT option under consideration cannot be eliminated. The top control alternative that is not eliminated is determined to be BACT. This process commonly involves the following five steps:

- **Step 1:** Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- **Step 2:** Eliminate all technically infeasible control technologies;

¹ Greenhouse Gas Tailoring Rule – (75 Fed. Reg. 31514, June 3, 2010)

² PSD and Title V Permitting Guidance for Greenhouse Gases, US EPA, November 2010 & March 2011.

- **Step 3:** Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;
- **Step 4:** Evaluate most effective controls and document results; and
- **Step 5:** Select BACT, which will be the most effective practical option not rejected based on economic, environmental, and/or energy impacts.

Historically, BACT has not been required for CO₂ or other GHGs. As a result, there is little precedent for this assessment. US EPA has issued general and refinery-specific guidance, but there are only a few available PSD BACT analyses to serve as examples. Nevertheless, BPH has prepared this BACT analysis consistent with US EPA guidance, and following the long-standing approach used for criteria pollutants.

E.2 Emission Units Subject to GHG BACT

Emission units that are subject to the requirement for GHG BACT are only those that are new or modified and have an increase in GHG emissions as a result of this project. Emission units that are unchanged by the project are not subject to BACT.³ The emission units that are subject to GHG BACT and their estimated total annual CO₂e emissions are included in the table below.

Table E-1. Units Subject to GHG BACT

Emission Unit	Status	Emissions of CO₂e (tons/yr)
Crude 1 Heater	New	248,000
Vac 1 Heater	New	82,700
Coker 3 Drum Vent	Modified	780
Coker Gas Plant Fugitives	Modified	10.9

³ In the preamble for the 1980 rule that established the current version of 40 CFR 52.21(j)(3), EPA explained that “BACT applies only to the units actually modified.” 45 FR 52676, 52681 (Aug. 7, 1980). Later in this preamble (at 52722), EPA elaborated as follows with a specific example:

The proposal required BACT for the new or modified emissions units which were associated with the modification and not for those unchanged emissions units at the same source. Thus, if an existing boiler at a source were modified or a new boiler added in such a way as to significantly increase particulate emissions, only that boiler would be subject to BACT, not the other emissions units at the source.

See also *PSD and Title V Permitting Guidance for Greenhouse Gases*, US EPA, March 2011 page 23.

E.3 New Refinery Heaters (Crude 1 & Vac 1) GHG BACT Analysis

This project will install three new natural draft process heaters. Two of the new heaters will serve together as new Crude 1 Furnaces and will each be designed to burn refinery fuel gas (RFG) at the design fuel flow rate of 225 MMBtu/hour (HHV). A third furnace with a design firing of 150 MMBtu/hr (HHV) will serve as the new Vacuum 1 furnace.

The heaters will generate three GHGs as a result of the normal combustion process: CO₂, CH₄ and N₂O. However, CO₂ is the by far the most significant. Nearly all of the fuel carbon (99.9%) in the fuel gas is typically converted to CO₂ during combustion. This conversion is relatively independent of boiler or heater fuel type. Fuel carbon that is not converted to CO₂ results in CH₄, CO, and/or VOC emissions due to incomplete combustion. The conditions that favor formation of N₂O are typically the same as those that favor emissions of methane, which are low temperature or incomplete combustion. Even in units with poor combustion efficiency, the level of these pollutants is insignificant compared to CO₂ levels. Therefore, the GHG analysis for combustion units focuses on just CO₂. CO₂ is an effective surrogate for all combustion CO₂ e. Also, options for controlling CO₂, such as ensuring complete combustion and maximum thermal efficiency, will minimize all three of the GHGs emitted.

Steps 1 & 2 - Identify Potential Controls and Assess Feasibility

A review of the RACT/BACT/LAER Clearinghouse (RBLC)⁴ and EPA Guidance Document on GHG Technologies⁵ was conducted to identify potential controls on refinery heaters. The following table shows the results of the RBLC search for similar gas-fired heaters or boilers showing the technologies employed to minimize GHG emissions.

⁴ <http://cfpub.epa.gov/RBLC/>

⁵ *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, US EPA Office of Air and Radiation, October 2010.

Table E-2. Snapshot of Relevant GHG BACT Determinations (2011-2012)

Facility	State or RBLC #	Emission Unit	GHG BACT Requirements
PORT DOLPHIN ENERGY LLC	FL-0330	4- 278 MMBtu/hr Boilers (Natural Gas Fuel)	Tuning, optimization, instrumentation and controls, insulation, and turbulent flow.
PYRAMAX CERAMICS, LLC - KING'S MILL FACILITY	GA-0147	9.8 MMBtu/hr Boiler (Natural Gas Fuel)	Good Combustion Practices, design, and thermal insulation. 5,809 tons CO ₂ e/rolling 12-months
NINEMILE POINT ELECTRIC GENERATING PLANT - ENTERGY LOUISIANA LLC	LA-0752	338 MMBtu/hr Auxiliary Boiler (Natural Gas Fuel)	Proper Operation and Good Combustion Practices Use of Natural Gas Fuel
GEISMAR ETHYLENE PLANT	LA-0759	180 MMBth/hr Cracking Furnace (Natural Gas Fuel)	Low-emitting feedstocks, Energy efficient equipment, Process design improvement, Low-emitting and low- carbon fuel (>25 vol% hydrogen, annual ave.)
PYRAMAX CERAMICS, LLC	SC-0113	5 MMBtu/hr Natural Gas Boilers	Good Design and Combustion Practices. Record type and quantity of fuel consumed.
Indiana Gasification (2012 IDEM permit 147-30464-00060)	Indiana (Not yet in RBLC)	2 - 408 MMBtu/hr Auxiliary Boilers (with approx. 20% utilization)	Use of low-carbon gaseous fuel (natural gas or SNG); and Energy efficient boiler design (utilizing an economizer, condensate recovery, inlet air controls and blowdown heat recovery) CO ₂ < 88,167 tons per rolling 12-month period

Based on a review of the available information and the project design, the control measures considered for the proposed process heaters include:

- Use of low-carbon gaseous fuel;
- Excess air minimization with O₂ monitoring and inlet air controls;
- Enhanced heat recovery (air preheat or convection section);
- Periodic burner tuning; and
- Post-combustion CO₂ capture and sequestration.

For the purpose of this analysis, each of these measures is considered technically feasible, and is evaluated further in the following sections.

Steps 3 & 4– Ranking and Evaluation of Remaining Controls

Low-Carbon Fuel

The carbon content of the fuel, relative to its Btu value, can have significant impact on the overall GHG emissions. Gaseous fuels such as natural gas or refinery fuel gas (RFG) create significantly less GHG emissions per Btu than liquid or solid fuels. RFG is a mixture usually containing primarily methane (C1), with some content of C2-C4 hydrocarbons, hydrogen, and other gases that are the non-condensable products from the top of light-end distillation columns in the refinery. RFG is produced at multiple locations in the refinery and is treated to remove H₂S, and routed to a central location (mix drum) to supply fuel to various locations in the refinery. As an example, the Toledo RFG streams have GHG emission factors in the range of 105-130 lb CO₂e/MMBtu. This compares favorably to 117 lb/MMBtu for natural gas and is significantly lower than 160 lb/MMBtu for diesel fuel and 210 lb/MMBtu for coal. The use of low-carbon RFG fuel is a feasible option, and is proposed for use by the heaters.

Excess Air Minimization with Oxygen Controls

Fuel combustion in refinery heaters is accomplished when the hydrocarbon in the fuel is oxidized into carbon dioxide and water. Oxygen is provided for combustion by ambient air that is mixed with the fuel prior to or during combustion. Optimum combustion is achieved through a mixture of air and fuel with a little excess air. If too little air is used, combustion may not be complete resulting in CO and unburned hydrocarbons being emitted as incomplete combustion products. However, if too much air is introduced, additional energy is needed to heat the air and maintain combustion temperature. Some of the heat to heat excess air is recovered. However, the excess air carries much of that heat out the stack. Air slightly in excess of the ideal stoichiometric fuel/air ratio is required for safety and to ensure complete combustion (minimizing CO and VOC emissions). A target of about 3% oxygen in the stack is considered optimal.

The use of too much air increases fuel consumption which translates to an increase in CO₂ emissions. Therefore, good control of the oxygen level is helpful to minimize fuel consumption in refinery heaters.

The amount of air drawn into a natural draft furnace can be controlled by adjustments to either stack dampers or inlet air registers. Installation of an oxygen monitor on the stack of the heater gives the operator the ability to make adjustments to

these controls to optimize the excess air. Adjustments can be done manually on a periodic basis, or in some cases, can be automated. In this case, automation of the excess air control utilizing O₂ monitoring is a feasible strategy to minimize fuel use CO₂ emissions. BPH is proposing to install automated trim air controls on the proposed heaters.

Enhanced Heat Recovery (Air Preheat or Convection Section)

Measures to capture and productively utilize as much heat as reasonably possible from the warm stack gases will improve the energy efficiency of a heater (and decrease its GHG emissions). Two common methods of stack gas heat recovery from process heaters are use of either an air preheater or a convection section. Both methods introduce additional heat transfer surface area in contact with the warm stack flue gas to capture additional heat. An air preheater uses the recovered energy to raise the temperature of the combustion air. A convection section uses the heat to preheat the process liquid being heated by the heater or for some other direct process heat purposes. Either method will result in increased thermal efficiency of the heater by recovering more heat from the flue gas. The choice of which heat recovery method is best is project-specific and can achieve equivalent efficiency results. Refinery heaters most often recover the heat to preheat the process fluid in a convection section. Air preheating is typically used only on very large boilers and forced/induced draft heaters. Air heating on natural draft heaters is rarely utilized due to the need to overcome significant gas-side pressure drop increases. Also, air preheat may increase NO_x emissions by increasing the flame temperature and causing more thermal NO_x formation.

BPH is proposing to install convection sections for heat recovery on the new Crude and Vac 1 heaters. The addition of this additional heat transfer area to preheat the process fluids will reduce the overall fuel consumption resulting in lower CO₂ emissions from fuel combustion. The convection section will be designed to reduce the stack temperature as much as is reasonable for the proposed heater design and operation. Sufficient temperature is required in the stack for the natural draft furnace to operate properly, and to avoid condensation in the stack.

Periodic Burner Tuning

Periodic maintenance of the burners, as well as checks and cleaning of fouling can help maintain heater and boiler efficiency. Poor burner operation can result in excess fuel usage as well as increased GHG emissions. Periodic burner tuning has been proposed in the recent EPA draft Industrial and Commercial Boiler and Heater MACT

regulation (Boiler MACT). This option is considered feasible and BPH will implement annual on-line burner tuning and inspections on the proposed heaters as currently required for large gas fired heaters at major sources in the current Boiler MACT rule.

Post-combustion CO₂ Capture and Sequestration

Carbon Capture and Sequestration (CCS) is a relatively new concept. As previously mentioned, in EPA's recent GHG BACT guidance, EPA takes the position that, *"for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO₂ -emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO₂ streams"*.⁶ However, the proposed refinery process heaters do not fit into either of these categories (i.e.; large emitting or high-purity). The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above quoted examples. However, some guidance specific to medium-sized natural gas boilers is provided in Appendix F to the guidance document which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option⁷.

Based on EPA's guidance, it seems clear that a CO₂ capture system for small to medium size combustion systems, such as the refinery process heaters, is not expected to be a reasonable BACT option. This is understandable because the capture of the CO₂ from a heater's exhaust is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four predominant factors: the heater exhaust's low CO₂ concentration, low pressure, low quantity of CO₂ available for capture, and the high variability of load for this unit. While these factors don't make it technically impossible, they do make it expensive and energy intensive as discussed below.

CO₂ Capture Difficulty: Gas fuel combustion exhaust streams have relatively low CO₂ concentrations. The exhaust streams are typically (6-9% CO₂ versus 12-15% for coal-boilers and >30% for high concentration industrial gas streams.) This means that for a gas fired process heater or boiler, a very large volume of gas needs to be treated to

6 PSD and Title V Permitting Guidance For Greenhouse Gases, November 2010, US EPA Office of Air and Radiation, pg. 34, 35.

7 PSD and Title V Permitting Guidance For Greenhouse Gases, March 2011, US EPA Office of Air and Radiation, Appendix F, pg. F-1.

recover the CO₂. Additionally, the low concentration and low pressure complicate the absorption and desorption of the CO₂, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO₂ stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO₂ capture on any gas combustion exhaust extremely difficult and expensive.

Estimated Costs for Carbon Capture: The fact that CCS is too expensive can be illustrated quickly using industry estimates. By far the most significant costs are for capture of the CO₂ from the exhaust, and compressing it to the pressure required for transport and sequestration. The capture and compression steps are very energy-intensive and would also result in additional emissions of criteria pollutants. The *Report of the Interagency Task Force on Carbon Capture and Storage* (August 2010) reports that carbon capture is estimated to cost approximately \$95/metric tonne CO₂ avoided (\$105/ton) for a post-combustion system on a new installation.⁸ These costs represent a levelized, or annualized, cost over the estimated life of the example configurations. If you apply this factor to the combined 330,864 tons/yr of CO₂ from the new Crude 1 and Vac 1 heaters, the cost for capture and compression alone (not including transport or sequestration) is approximately \$34,600,000 per year. This cost estimate is an annual cost (including capital recovery costs). Over the first 10 years of operation these costs would exceed \$300 million dollars. This is clearly an excessive cost.

Energy and other pollutants from Carbon Capture: In addition to the extremely high costs for CCS, it should be recognized that a large portion of these costs are energy related. The two largest energy requirements of carbon capture post-combustion are the energy required to regenerate the solvent and the energy to compress the captured CO₂ to typical pipeline pressures. Satisfying these high additional energy requirements create significant additional CO₂ emissions and emissions of other conventional pollutants.

For example, regeneration of the solvent in available CO₂ capture technologies require approximately 1,550-3,000 Btu/lb of CO₂ removed.⁹ This would equate to 117-226 MMBtu/hr of increased energy use associated with the capture of CO₂ from the two

⁸ Various literature sources report a fairly wide range of costs for employing CCS systems (typically 60-120 \$/ton CO₂ controlled). The range spanned by these cost estimates is driven primarily by site-specific considerations (especially CO₂ concentration) and energy cost assumptions. In addition, estimates of the future performance of components of the capture, transport, storage, measurement and monitoring systems are uncertain.

⁹ *Report of the Interagency Task Force on Carbon Capture and Storage*, (August 2010)

new heaters (which themselves have a combined design firing rate of (heaters with a design firing of 600 MMBtu/hr.) This does not include the significant power is required to compress the captured CO₂ to typical pipeline pressures (1,500 – 2,200 psia).

These significant additional requirements for steam and electricity require fossil fuels to be combusted either on or off site. These energy demands of CCS contribute to its significant cost and generate negative environmental consequences through the extra criteria pollutant emissions.

Sequestration Site Non-availability: Because of the extremely high costs of carbon capture and compression, BPH does not believe that CCS is an economically feasible option for GHG controls on this project. Further, BPH is unaware of any available suitable sequestration site or CO₂ transportation infrastructure that could be used by this project. Therefore, we additionally believe that CCS is infeasible due to lack of currently available sequestration site for permanent storage of any CO₂ captured. A few of the main challenges and issues of sequestration are briefly discussed below.

- **Access to a suitable sequestration site.** BPH does not have access to a suitable sequestration site, nor can one be developed in any timeframe compatible with this project. While sequestration is being studied for use in this region, there is presently no practical option. Funding from the Department of Energy (DOE) is supporting a substantial research and demonstration initiative called the Regional Carbon Sequestration Partnership (RCSP) program. This program has begun several large-scale CO₂ injection research projects. However, the results of these demonstrations won't be known for some time. Also, given the unprecedented nature of the CO₂ sequestration, many technical and legal issues remain to be addressed including the public acceptability of storage at any given site. These issues make the ultimate development of future sites uncertain.
- **Access to available transportation infrastructure.** There are a number of CO₂ commercial outlets in the Gulf Coast and some western states for CO₂, primarily for use in enhanced oil recovery. These operations are served by a number of CO₂ pipelines. However, there is no existing pipeline infrastructure within hundreds of miles of the BPH facility. The nearest is over 700 miles away in Jackson, Mississippi. The logistical challenges of constructing a pipeline from the BPH facility hundreds of miles to join up with the existing CO₂ pipeline infrastructure is completely impractical.

Step 5 - Selection of GHG BACT

For the technical, economic, and environmental reasons stated above, post-combustion capture of CO₂ from the proposed heaters is not considered an applicable and available control option. All other remaining technically feasible GHG control options are proposed as BACT:

- Use of low-carbon gaseous fuel (RFG or natural gas);
- Excess Air Minimization with O₂ monitoring and Inlet Air Controls
- Heat Recovery through use of a convection section; and
- Annual burner tuning and heater inspection.

Compliance will be demonstrated through records of the heater design, records of fuel usage, and maintenance records. Additionally, total annual CO₂e emissions shall not exceed 248,149 tons per rolling 12 months for the new Crude 1 heater and 82,176 tons per rolling 12 months for the new Vacuum 1 heater. These emissions will be calculated monthly to develop a rolling 12-month sum.

E.4 Coker 3 (P036) Drum Vent GHG BACT Analysis

During the bulk of the delayed coker operating cycle, vapors from the coke drum are routed to the coker product fractionator for liquid and gas product recovery and there are no emissions to the atmosphere. At the end of the coke drum cycle, after the drum is taken off line, it is depressured to a blowdown recovery system which routes the gas to the refinery fuel gas system.

The first emissions event occurs when the coke drum is vented to the atmosphere prior to it being opened to remove the accumulated coke. Residual vapors from the coking process that exist in equilibrium based on the temperature and pressure of the coke drums are released to the atmosphere during this step. Prior to this atmospheric venting, the drum has been steamed out and water flooded. The gases from this atmospheric venting consists of primarily steam, along with residual vapors from the coking process, and includes the GHGs methane (CH₄) and CO₂.

There were no coking units found in the RBLC database. However, the EPA GHG Guidance for Refineries¹⁰ listed lowering the pressure of the coke drum to 2 to 5 psig to minimize direct venting emissions as a possible GHG control measure. This option is technically feasible and was evaluated by BPH for Coker 3 based on the modifications occurring as part of the TFO project.

BPH already routinely depressures to less than 5 psig before opening the atmospheric vent on Coker 3. Depressuring further to 2 psig before venting would result in even less emissions. BPH understands that several refineries already operate with a 2 psig vent pressure limit. Therefore, BACT is proposed as venting to the blowdown recovery system until the coke drums are depressured to no more than 2.0 psig. Compliance will be demonstrated through recording the pressure prior to coke drum vent opening to the atmosphere.

E.5 Fugitive Emissions GHG BACT Analysis (Coker 3 Unit (P036))

Small leaks from the piping connectors and the stem packing of valves can be sources of fugitive GHG emissions for equipment containing CH₄. The new piping components of the modified Coker gas plant and any new natural gas piping in the Coker 3 unit will contain CH₄. These piping components are designed not to leak, but statistically, a few leaks are expected to occur from time to time. As required by multiple regulations, all new VOC fugitive emission components will be integrated into the BP-Husky Leak Detection and Repair (LDAR) program. This program is designed to comply with applicable NSPS Subpart GGGa and Refinery MACT (Subpart CC) standards. The LDAR program promptly identifies leaking components through regular monitoring and institutes a schedule for the repair.

For the piping, such as the refinery fuel gas piping in the new piping of the modified coker gas plant which contains significant CH₄, these VOC LDAR regulations will serve to help control GHG emissions as well. BPH further proposes to extend the use of the existing refinery LDAR program to also include any new natural gas piping installed by this project in the modified process Coker 3 process unit (P036). Natural gas, which is predominately CH₄, is not a VOC, so it would not otherwise be required to be included in the LDAR plan.

¹⁰ *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, US EPA Office of Air and Radiation, October 2010.

Such an LDAR program is a technically feasible method of controlling CH₄ emissions from equipment leaks. The fugitive GHG emissions after employment of these control practices are extremely small.

Therefore, compliance with the applicable NSPS GGGa and Refinery MACT (CC) LDAR regulations is proposed as BACT for fugitive GHG (CH₄) emissions from new piping components. Likewise, any new natural gas piping in the Coker 3 unit is proposed to be included in the refinery LDAR program.

Appendix F

Refinery Fuel Gas Total Reduced Sulfur (TRS) Data

Appendix F

Refinery Fuel Gas Total Reduced Sulfur (TRS) Data

TRS Background

While the BPH refinery's refinery fuel gas amine treatment system is extremely effective in removing hydrogen sulfide (H_2S), it does not remove other sulfur species such as methyl mercaptan (CH_4S) which are present in some refinery fuel gas streams, especially in the fuel gas produced from Coking units.

Non- H_2S sulfur species in refinery fuel gas streams have not traditionally been monitored or specifically regulated in the refining industry (e.g.; only H_2S is monitored is required per NSPS Subparts J and Ja). However, in recent years, industry and US EPA have become aware of the potential for significant quantities of non- H_2S sulfur in some refinery fuel gas streams.

Toledo TRS Test Results

BPH recently conducted a testing program to measure the total amount of sulfur, including Total Reduced Sulfur (TRS) in the BPH refinery fuel gas streams. The data from this Toledo refinery testing provides a more accurate basis for estimating past actual and future potential SO_2 emissions from heaters versus the historic method utilizing only fuel H_2S data.

The BPH Toledo refinery conducted testing of TRS in the fuel gas system during three different testing periods (Nov. 2010, Feb. 2011, and May 2011). Each of the three testing periods consisted of at least 50 hours of continuous monitoring of TRS. Table F-1 shows the results for each of the refinery's three refinery fuel gas systems. These TRS results include H_2S and non- H_2S sulfur.

As shown, the highest TRS values were found in the Coker 3/EPA fuel gas stream. The intermediate concentrations of organic sulfur compounds found in the TIU fuel gas are believed to result primarily from Coker fuel gas that becomes a constituent of the TIU fuel gas.

Table F-1 Average Refinery Fuel Gas TRS Testing Results

Test Date	Average Test Results (TRS ppm_v)		
	East Side Mix Drum	TIU Mix Drum	Coker 3/EPA Fuel Gas
November 2010	35	192	272
February 2011	Not tested	190	460
May 2011	Not tested	329	372
Average (used for Past Actual calculations)	N/A	237	368
Approx. Future TRS with TFO project planned improvements	N/A	Approx. 70 (annual average)	

TFO Project Improvements affecting TRS

As part of the TFO project, BPH will implement improvements to the Coker gas processing to provide better recovery of light hydrocarbons and organic sulfur compounds that currently enter the refinery fuel gas system. Reducing the amount of organic sulfur compounds in the refinery fuel gas system will lower SO₂ emissions from many refinery heaters. BPH estimates that the total sulfur in both the Coker 3 and TIU fuel gas streams will be reduced to approximately 70 ppm on an annual average basis.

Appendix G

Proposed Interim Group SO₂ Limit

Appendix G

Proposed Interim Group SO₂ Limit

Description of Requested Permitting Action

As discussed in Section 4.2 of this application, although BPH is planning to implement significant improvements to refinery fuel gas sulfur treatment as part of the TFO project, due to practical project execution constraints, these improvements cannot be fully in place immediately upon startup of all the other elements of the TFO project. Therefore, BPH proposes an interim SO₂ group limit be imposed on project affected sources until the permanent SO₂ limits on the heaters take effect. The purpose of this interim group limit will be to keep project SO₂ increases below the PSD significance level until final new limits on individual heaters take effect.

This group SO₂ limit is set at a level no higher than the total baseline actual emissions for the emission units involved in, or affected by, the TFO Project and all projects that are contemporaneous with the TFO Project. As such, this limit assures that no significant net emissions increase will occur during the period between the time the interim group limit takes effect and the time the “final” limits go into effect.

The new interim group SO₂ limit applies to the following sources: Coker 3 Heater (B032), Coker 2 Heater (B017), Crude Vacuum 2 Heater (B019), NHT Heater (B022), BGOT Heater (B030), the East BGOT Heater (B033), the Crude 1 Heater (B015), the Vacuum 1 Heater (B031), the ADHT Heater (B029), the East Alstom Boiler (B034), the West Alstom Boiler (B035), the SRU No. 1 (P009), the TRP SRUs (P037), the FCCU (P007). This group limit is proposed to take effect upon the startup of the first element of the TFO project that could increase SO₂ emissions, the startup of the replacement Crude and Vacuum 1 heaters. The interim group limit will be applicable until the later of:

- a) Fifteen (15) months after the initial startup of the TFO project; or
- b) The completion of construction and initial shakedown of the modifications to the Coker gas plant.

Upon its expiration, it will be replaced by the final limits discussed in elsewhere in this application.

This proposed group limit has already been separately proposed as part of a request for an administrative permitting action under Air Services Application M0001922 submitted Sept. 28, 2012. However, since this permit condition will serve as part of the PSD netting demonstration for the TFO project, BPH proposes that it be incorporated into the TFO permit as well.

Table G-1 shows the baseline emissions for the affected sources which serve as the basis of the group limit. The baseline period chosen is the average emissions for 2004 and 2005 (which is the baseline period for the TFO project and was the baseline period used in the original permitting of other contemporaneous projects.) Baseline actual emissions for heaters were calculated using the actual annual average firing rate for the 2004-05 baseline period and the sum of average H₂S fuel gas content as determined by continuous H₂S monitoring and the average results of the testing of non-H₂S sulfur described in Appendix F above. Where applicable, emissions in excess of current allowable levels are excluded from the baseline emissions. Details of the calculations supporting these emissions numbers are presented Air Services Application M0001922. Baseline actual emissions for the SRU and FCCU were determined from SO₂ CEMS data for the baseline years.

Table G-1 Baseline Emissions and Proposed Interim Group Limit

OEPA ID	Process Unit	Permit Capacity (HHV) (MMBtu/hr)	Baseline (2004 - 2005) (MMBtu/hr)	Baseline SO ₂ Emissions tpy	
Existing Heaters Affected by Recent Projects					
B015	Crude 1 Heater (existing)	325	321	36.56	
B031	Vac 1 Heater (existing)	140	99	11.25	
TBD	New Crude Heater(s)	450	0.0	0.00	
TBD	New Vac 1 Heater	150	0.0	0.00	
B019	CV 2 Heater	258	216	21.02	
B032	Coker 3 Heater	247	228	20.46	
B017	Coker 2 Heater	77	42	4.77	
B029	ADHT Heater	20	10	0.18	
B022	Naphtha Hydrotreater Heater	77	63	7.15	
B030	BGOT Heater	33	23	2.62	
B033	East BGOT Heater	33	0	0.00	
B018	FCC Preheat Heater	108	31	3.52	
B001	Hydrogen Plant Heater	238	190	4.32	
B013	Reformer 1 Regen Heater	5	2	0.24	
B014	Reformer 1 Heater	280	151	19.08	
B006	Reformer 2 Heater	306	235	5.32	
B005	Reformer 2 Regen Heater	32	8	0.17	
Other Affected Emission Units					
B034/ B035	Alstom Boilers (incremental steam)	430	NA	0.00	
P009/ P037	SRU 1/ SRU 2&3	NA	NA	32.87	
P007	FCCU/CO Boiler	NA	NA	800	
Sum of Baseline Emissions				970	SO₂, tpy
Proposed SO₂ Group Limit				970	SO₂, tpy

Proposed Compliance Determination Method

Historically, the emission estimates of SO₂ emissions from refinery heaters have been based on measurement of the H₂S concentration in the refinery fuel gas fired. However, to demonstrate compliance with the above proposed limits, the refinery has proposed an improved method for monitoring the refinery fuel gas streams for which recent testing has shown significant non-H₂S sulfur content. For those heaters using such fuel gas, BPH proposes to install and utilize continuous Total Sulfur analyzers. This total sulfur monitoring methodology applies to all of the above heaters except the Reformer 3 heater.

The Reformer 3 heater uses fuel gas which prior testing has indicated contains very little non-H₂S sulfur. Emissions calculations for Reformer 3 Heater's SO₂ emissions is proposed to be based on use of the existing ESMD H₂S continuous monitoring plus an assumed non-H₂S sulfur content of 35 ppm based on past testing (or more recent representative test results if future testing is performed).

Emissions from the FCCU and SRU will be determined from monitoring data provided by existing continuous SO₂ emissions monitors. The emission contribution from the Alstom Boilers will be based on the incremental firing rates necessary to satisfy the maximum steam demand for (a) the contemporaneous FCCU Preheat Project (31 mmBtu/hr) and (b) the gas plant to be added as a part of the TFO project (62 mmBtu/hr) times the total sulfur concentration in the fuel gas to the Alstom Boilers as determined from continuous total sulfur monitoring of its fuel gas.