USCG Comment #1:

Volume 5 Part 1 – Attachment 2-1 General Conformity: 'Vessel unloading' emissions included in the NNSR permit do not include ship hoteling emissions during unloading. Therefore, hoteling emissions must be included in the general conformity applicability determination.

Response:

Hoteling emissions were included in the general conformity applicability determination. However, the emissions calculations page which demonstrates this appears to have been inadvertently omitted from Appendix A (Emissions Calculation Methodology) of the August 2007 submittal of Volume Five, Part One – Attachment 2-1, titled "Support Document for Clean Air Act General Conformity Determination - Safe Harbor Energy Deepwater Port Project." Attachment 1-1 is that calculation page, with the header "Operational Activities (2014 and Beyond)." The page shows the calculation of the ship hoteling emissions that were included in the totals shown in Tables 4-1 and 4-2 of the report body. The inclusion of these emissions in the general conformity analysis rather than the Non-attainment New Source Review (NNSR) permit is consistent with prior determinations made by the D.C. Circuit Court of Appeals, and subsequently the EPA, regarding which emissions units should be included in stationary source permits. The inclusion in the general conformity analysis is also consistent with procedures discussed in the meeting that the project had with EPA Region 2 on April 4, 2006.

Attachment 1-1

- Operational Activities (2014 and Beyond)

Operational Activities (2014 and Beyond)

As described in Section 4 of this report, operational activities (in 2014 and beyond) subject to general conformity include operations of the LNG carriers (not including those covered by the nonattainment New Source Review permit application), and the use of tugs when LNG carriers arrive and depart.

The # of trips depends on the size of LNG carrier calling on the ports. New carriers are being designed with capacities of up to 270,000 m^3 LNG, but for purposes of this analysis we will conservatively assume relatively small LNG carrier sizes, which increases the number of trips:

Assumed LNG carrier capacity:	130,000	m^3				
Number of trips corresponding to	2.0	Bcfd =	258	per year or	21.5	per month
	2,393	hours of unloading/yr a		14,000	m^3/hr	

Fuel-burning units on LNG carrier are at full load within the Hudson Canyon-to-Ambrose shipping lane. The carrier picks up its mooring pilot and terminal crew (e.g., by crew boat) just outside the lane. Although the carrier's speed is restricted as it moves to the tug pick-up point (which is still outside the Safety Zone), vessels' fuel-burning units are required to be at full load for safety purposes (maximum maneuverability). As the tugs pick up the vessel and backs it into its berth, the load on its fuel-burning units decreases to just what is needed for hotelling/electrical power requirements. During unloading, three of the four tugs will have its main engines off, while the fourth will be idling in standby. After unloading, the tugs tow the vessel and orient it towards the Ambrose-to-Nantucket shipping lane, where it departs.

Assume	4	tugs ea. with		5,000	hp main engines,	
		2	90	kW aux. engines at	50%	load
	Tugs dispatched from shore would spend appro				1.0	hr in State waters and
					1.0	hr in Other waters
	each way, but are only dispatched from shore every				2.0	LNG
	carrier trips (being based at the Island in the meantime)					
Crew boat	1,000	hp for	1	hr/trip, in Safety Zone		

	LNG Carrier		Tugs (each)			
Information for each trip	Hours	Load (kW)	Hours	Main engine hp	Aux. engine hp	
Transit to tug pickup (in State Waters)	NA	NA	0.5	4,000	121	
Transit to tug pickup (in Other Waters)	0.5	30,000	0.5	4,000	121	
Pickup/towing (in Other Waters)	0.5	3,000	0.5	3,000	121	
Towing/berthing (in Safety Zone)	1.5	3,000	1.5	3,000	121	
Hotelling during Unloading (Safety Zone)	9.3	3,000	9.3	1,000	121	only one tug main engine
Tow out (in Safety Zone)	1.5	3,000	1.5	3,000	121	
Return trip (in Other Waters)	varies	30,000	0.5	4,000	121	
Return trip (in State Waters)	NA	NA	0.5	4,000	121	

LNG Carrier emissions depend on technology type; maximum annual emissions have been calculated in the air permit application for the electrical load of 4,300 kW associated with unloading activities:

	VOC	NO_x	CO	$PM_{2.5}$	SO_2
Max. annual unloading emissions (TPY)	11.7	70.0	42.2	24.4	95.6
Max. average g/kWh for LNG carriers	1.0	6.2	3.7	2.2	8.4
Emission factors for tugs (main engines) and crew boat, g/hp-hr	0.46	9.65	1.25	0.19	0.17
Emission factors for tug aux. engines, g/hp-	0.20	7.46	1.12	0.21	0.19

Monthly Emissions, Excluding Unloading

	VOC	NO_x	CO	$PM_{2.5}$	SO_2
State Waters (tugs only)	0.2	3.7	0.5	0.1	0.1
Safety Zone	1.4	17.0	4.8	2.1	7.6
Other Waters (outside shipping lanes)	0.6	7.6	2.1	0.9	3.4

Annual Emissions, Excluding Unloading

	VOC	NO_x	CO	$PM_{2.5}$	SO_2
State Waters (tugs only)	2	45	6	1	1
Safety Zone	17	204	57	25	91
Conformity Applicability Threshold	50	100	NA	100	100
Other Waters (outside shipping lanes)	7.7	90.8	25.5	11.3	40.6

USCG Comment #2:

Air Quality Topic Report sections addresses emissions from stationary sources during the operating phase, not emissions associated with construction of deepwater port or mobile sources. Please provide additional information on construction related emissions, including stationary and mobile sources used in the construction of the Project; on-shore sources such as emissions related to equipment fabrication and staging areas and transportation of materials to the Project; pipeline construction activities; emission sources related to project decommissioning; and mobile sources relate to project operations, including LNGC emissions from the time they enter the U.S. Exclusive Economic Zone, and mobile sources supporting the port such as crew vessels, supply vessels, and other support vessels .

Response:

The August 2007 submittal of Volume Five Part One – Attachment 2-1, "Support Document for Clean Air Act General Conformity Determination - Safe Harbor Energy Deepwater Port Project" provides additional information on construction-related emissions, including stationary and mobile sources used in the construction of the Project; on-shore sources within the New York Metropolitan Area (NYMA) such as emissions-related to equipment fabrication (e.g., the 19,000 33-ton CORE-LOC concrete armor units), staging areas and transportation of materials to the Project; pipeline construction activities; and mobile sources related to project operations, including LNGC emissions within the Safety Zone, as well as mobile sources supporting the port such as crew boats (which also deliver supplies) and other support vessels (i.e., tugs). Volume Three, Part One, Topic Report Eight – Air and Noise Quality refers to this conformity determination in sections related to construction emissions and consequences.

On-shore emissions associated with fabrication activities outside the NYMA – e.g., the manufacturing of the concrete caissons, and transportation of caissons from their point of origin to New York waters – are not included, as these emissions are anticipated to be well below the general conformity applicability thresholds that would apply, even in serious nonattainment areas. For the purpose of documentation, these construction activities may take place at existing permitted facilities.

For purposes of analyzing the potential effects of the Project under NEPA, the Project has included estimations of the propulsion emissions within the U.S. Exclusive Economic Zone (EEZ) from LNG tankers that will travel to and from the Safe Harbor facility. Since the project proponent does not own an LNG fleet, certain assumptions are made about the tankers that may travel to the facility. As described in the table provided in Attachment 1-1 in response to USCG Comment #1, the analysis conservatively calculates emissions based on an assumption of small tankers (130,000 m^3). Although vessels using any technology other than steam turbines are likely to be larger, this is the most conservative estimate of emissions because it requires more vessels to deliver 2.0 bcfd. For travel within the EEZ and outside the safety zone, worst-case (highest emitting) technologies were assumed (within the limits allowed by the permit) and an average sulfur content of 2.7% per EPA guidance (ICF 2006) (refer to Attachment 2-1), even though the industry expects that newer tankers will use cleaner fuels for propulsion per the latest IMO/MARPOL resolutions. As shown in the permit application (Volume Two, Part One, Exhibit X), the worst-case emission factors for SO_2 are those associated with steam turbines, so the analysis has been based on these vessels for those pollutants. The worst-case emission factor for NO_x is for slow-speed diesels, but the permit limits the use of these vessels so that they can deliver no more than 11 million m^3/yr of the facility's 33.5 million m^3/yr of LNG, and that restriction has been reflected in the calculations. The next-worst case emissions for NO_x (and the worst-case for all other pollutants) are medium-speed diesels, which have been assumed for the balance of the analysis. Based on an estimated average LNG carrier cruising speed of approximately 14 knots (ICF 2006) (refer to Attachment 2-1), it was calculated that each LNG carrier will be traveling for approximately 26 hours (roundtrip) in the EEZ,

outside the Safety Zone and pilot pickup areas. Emissions and supporting calculations are shown in Attachment 2-2.

References:

ICF Consulting. 2006. Current Methodologies and Best Practices in Preparing Port Emission Inventories. Final Report. Prepared for U.S. Environmental Protection Agency.

Attachment 2-1

- "Current Methodologies and Best Practices in Preparing Port Emission Inventories," Final Report, pages 17, 18, and 20 (ICF 2006)

Current Methodologies and Best Practices in Preparing Port Emission Inventories

Final Report

January 5, 2006

Prepared for
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Table 2-5: Vessel Movements and Time-In-Mode Descriptions within the MEPA Areas

Summary Table Field	Description
Call	A call is one entrance and one clearance from the MEPA area.
Shift	A shift is a vessel movement within the MEPA area. Shifts are contained in calls. While many vessels shift at least once, greater than 95 percent of vessels shift three times or less within most MEPA areas. Not all MEPAs record shifts.
Cruise (hr/call)	Time at service speed (also called sea speed or normal cruising speed) usually considered to be 94 percent of maximum speed and 83 percent of MCR. Calculated for each MEPA area from the port boundary to the breakwater or reduced speed zone. The breakwater is the geographic marker for the change from open ocean to inland waterway (usually a bay or river).
Reduced Speed Zone (RSZ) (hr/call)	Time in the MEPA area at a speed less than cruise and greater than maneuvering. This is the maximum safe speed the vessel uses to traverse distances within a waterway leading to a port. Reduced speeds can be as high as 15 knots in the open water of the Chesapeake Bay, but tend to be more in the order of 9 to 12 knots in most other areas. Some ports are instituting RSZs to reduce emissions from OGVs as they enter their port.
Maneuver (hr/call)	Time in the MEPA area between the breakwater and the PWD. Maneuvering within a port generally occurs at 5 to 8 knots on average, with slower speeds maintained as the ship reaches its PWD or anchorage. Even with tug assist, the propulsion engines are still in operation.
Hotelling (hr/call)	Hotelling is the time at pier/wharf/dock (PWD) or anchorage when the vessel is operating auxiliary engines only or is cold ironing. Auxiliary engines are operating at some load conditions the entire time the vessel is manned, but peak loads will occur after the propulsion engines are shut down. The auxiliary engines are then responsible for all onboard power or are used to power off-loading equipment, or both. Cold ironing uses shore power to provide electricity to the ship instead of using the auxiliary engines. Hotelling needs to be divided into cold ironing and active to accurately account for reduced emissions from cold ironing.

Cruise speed is generally taken as 94 percent of the maximum service speed listed in Lloyd's Data. Distances from the maximum port boundary (defined in Section 2.1 above) to either the RSZ or the breakwater[16] are used with the cruise speed to determine cruise times into and out of the port. Some MEPAs record which route was used to enter and leave the port and this information can be used to determine the actual distances the ships travel. Average cruise speeds by ship type from the PoLA inventory are given in Table 2-6. While actual cruise speeds should be calculated in a detailed inventory, these can be used as surrogates for more streamlined analyses.

RSZ time-in-mode also is an estimation based on average ship speed and distance. Pilots generally can report average ship speeds for a precautionary or reduced speed zone. As was found in the PoLA study, ships tend to move at less than the maximum RSZ speed. For instance, in the PoLA, the precautionary zone speed is 12 knots or less. Starcrest found, through conversations with pilots and its vessel boarding program, that auto carriers, container ships, and cruise ships average 11 knots in the RSZ while other ship types average 9 knots in the RSZ. In addition, compliance with RSZ speeds should be determined.

Maneuvering time-in-mode is estimated based on the distance a ship travels from the breakwater to the PWD. Average maneuvering speeds vary from 3 to 8 knots depending on direction and ship type. Generally, outbound speeds are greater because the ship does not need to dock. Ships go from half speed to dead slow to stop during maneuvering. Time-in-mode varies depending on the location of and the approach to the destination terminal and turning requirements of the vessel. Maneuvering speeds should be determined through conversations with the pilots. In the PoLA inventory, inbound auto carriers, container ships, and cruise ships averaged 7 knots during maneuvering, while all other ship types averaged 5 knots. On the outbound route, all vessels averaged 8 knots.

[16] Not all ports have a physical breakwater. Thus for these ports, an imaginary breakwater needs to be defined.

Table 2-6: Average Cruise Speeds by Ship Type (Port of Los Angeles)

Ship Type	Cruise Speed (knots)
Auto Carrier	13.80
Bulk	17.58
Container Ship	21.26
Cruise Ship	18.06
General Cargo	14.69
Miscellaneous	14.10
OG Tug	9.40
RORO	13.91
Reefer	18.90
Tanker	13.60

One Knot, *or one nautical mile per hour, is equivalent to 1.15 miles per hour.*

Hotelling should be calculated by subtracting time spent maneuvering into and out of a PWD from the departure time minus the arrival time into a port. If possible, anchorage time (time at anchorage within the port but not at a PWD) should be broken out from time at a PWD. Some MEPAs record shifts as well and this will allow for further refinements in maneuvering time. During hotelling, the main propulsion engines are off, and only the auxiliary engines are operating, unless the ship is cold ironing. Hotelling times can also be determined from pilot records of vessel arrival and departure times when other data is not available. Actual hotelling times should be calculated for each individual port, because hotelling is generally a large portion of the emissions at a port. Hotelling times should be separated for those ships that use cold ironing at a port and those that do not. It is important to also look for outliers (ships with extremely long hotelling times) to eliminate those in the average since they may represents ships at a PWD but not with auxiliary engines on.

Many variables affect one or more time-in-mode calculations. These variables cannot be accurately predicted for a ship-type category over an entire year of calls. Traffic conditions, weather, vessel schedule, and current are some of the more important variables that dictate how much time is required at each time-in-mode, especially maneuvering as described below.

- Traffic conditions may make travel in the waterway slower because a wake is more damaging in a congested waterway, forcing vessels to be more careful and travel at slower speeds.
- Bad weather in the form of high winds causes vessels to be more difficult and less predictable to maneuver. Rain and fog obscure visibility and can make a vessel's maximum speed in the waterway one-third of what it would be on a clear day. Docking at a PWD takes much longer in bad weather and on busy days, resulting in more time spent at maneuvering speeds.
- Vessel schedule also affects time-in-mode. The waterway pilot is at least partially responsible for keeping the vessel on schedule to meet the tug assist for docking, the loading or unloading crews, and/or the bunkering vessel. If a vessel is ahead of schedule, the pilot may use slower speeds in the waterway to conserve fuel and arrive closer to schedule. If the vessel is behind schedule, the pilot may push speeds to the maximum safe limit in an attempt to get back on schedule.

Table 2-7: Auxiliary Engine Load Factor Assumptions

Ship-Type	Cruise	RSZ	Maneuver	Hotel
Auto Carrier	0.13	0.30	0.67	0.24
Bulk Carrier	0.17	0.27	0.45	0.22
Container Ship	0.13	0.25	0.50	0.17
Cruise Ship	0.80	0.80	0.80	0.64
General Cargo	0.17	0.27	0.45	0.22
Miscellaneous	0.17	0.27	0.45	0.22
OG Tug	0.17	0.27	0.45	0.22
RORO	0.15	0.30	0.45	0.30
Reefer	0.20	0.34	0.67	0.34
Tanker	0.13	0.27	0.45	0.67

Propulsion Engine Emission Factors

The weakest link in deep sea vessel emission inventories is the emission factors for Category 3 ship engines. Emission factors continue to be derived from limited data. Emission testing of OGVs is an expensive and difficult undertaking; and thus, emissions data are relatively rare. In most cases, the power generated is only estimated, leading to inaccuracies in the overall emission factors.

The most recent study of emission factors was done by Entec, and these factors are generally accepted as the most current set available.[20] Entec analyzed emissions data from 142 propulsion engines and included 2 of the most recent research programs, Lloyd's Register Engineering Services in 1995 and IVL Swedish Environmental Research Institute in 2002. Entec lists individual factors for three speeds of diesel engines (slow-speed diesel (SSD), medium-speed diesel (MSD), and high-speed diesel (HSD)), steam turbines (ST), and three types of fuel (RO, MDO, and MGO). Starcrest used these factors in their PoLA inventory with the following assumptions:

- All main engines operate only on RO (intermediate fuel oil 380 or similar specification with average sulfur content of 2.7 percent).
- Slow speed engines have maximum engine speeds of less than 130 rpm.
- Medium speed engines have a maximum speed of greater than 130 rpm and typically over 400 rpm.
- All turbines are steam boiler turbines.

Currently recommended emission factors are shown in Table 2-8. It should be noted that Entec does not list PM factors for either PM_{10} or $PM_{2.5}$. PM emission factors are the most controversial as measurement of PM emissions on a ship is particularly difficult and there is much variation between sources. Generally

[20] Entec UK Limited, *Quantification of Emissions from Ships Associated with Ship Movements between Ports in the European Community*, prepared for the European Commission, July 2002.

Attachment 2-2

- LNG Carrier Emissions in EEZ

LNG Carriers in EEZ

The # of trips depends on the size of LNG carrier calling on the ports. New carriers are being designed with capacities of up to 270,000 m^3 LNG, but for purposes of this analysis we will conservatively assume relatively small LNG carrier sizes, which increases the number of trips:

Assumed LNG carrier capacity:	130,000	m^3				
Number of trips corresponding to	2.0	Bcfd =	258	per year or	21.5	per month
Max. SSD/RO vessels:	11,000,000	m^3 =	85	per year or	21.5	per month

	LNG Carrier	
Information for each trip	Hours	Load (kW)
Roundtrip per LNG carrier	26	30,000

LNG Carrier emissions depend on technology type; maximum annual emissions have been calculated in the air permit application for the electrical load of 4,300 kW associated with unloading activities:

	VOC	NO_x	CO	$PM_{2.5}$	SO_2
g/kWh for SSD/RO LNG carriers	0.4	14.7	1.59	0.8	6.51
Max. g/kWh for other LNG carriers	1.5	10.6	4.7	2.4	10.08

Monthly Emissions in EEZ (outside Safety Zone & excluding tug pickup)

	VOC	NO_x	CO	$PM_{2.5}$	SO_2
All LNG carriers	27.7	271	86.6	44.3	186

Annual Emissions in EEZ (outside Safety Zone & excluding tug pickup)

	VOC	NO_x	CO	$PM_{2.5}$	SO_2
All LNG carriers	332	2,647	1,039	532	2,233

USCG Comment #3:

Volume 5 Part 1 – Attachment 2-1 General Conformity Page 2-1: The document states that sulfur dioxide (SO2) emission factors for marine vessels were adjusted to account for lower sulfur levels in the fuel, but does not discuss the assumptions or methods used. EPA recommends including a discussion on the method used to adjust the emission factors. Additionally, ASIG assumed a sulfur level of 500 parts per million (ppm) in marine diesel fuel during the 2012-2014 construction years. EPA notes that actual sulfur levels during those years would be 15 ppm and ASIG's analysis is conservative.

Response:

SO_2 emissions were calculated by multiplying fuel consumption rates by 0.05% (to correspond to 500 ppmw sulfur) and a factor of 2 lb SO_2 produced per lb S in fuel (i.e., essentially 100% conversion of sulfur to SO_2). Fuel consumption was in turn calculated from the CO_2 emission factors by multiplying by (12 lb C in fuel) divided by (44 lb CO_2 produced) and (1 lb fuel)/(0.867 lb carbon); the carbon content of 86.7% is from the Entec report, "Quantification of emissions from ships associated with ship movements between ports in the European Community," July 2002, Table C.2. Pertinent pages from this reference are provided in Attachment 3-1.

We acknowledge the conservativeness of the SO_2 factors. Given that construction activities spanned multiple years (and that SO_2 was not an issue with respect to general conformity), we assumed the highest (500 ppm) sulfur content that would be present during that timeframe. As noted in Section 2 of Attachment 2-1, 40 CFR 80.510 requires that the sulfur content for nonroad diesel be no more than 15 ppm as of June 2010, and that marine diesel to contain no more than 15 ppm sulfur by June 2012.

Attachment 3-1

- "Quantification of emissions from ships associated with ship movements between ports in the European Community", Table C.2 (Entec 2002)

European Commission

Quantification of emissions from ships associated with ship movements between ports in the European Community

Final Report

July 2002

Entec UK Limited

Report for

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Table C.2. Marine fuel types and general properties. Data based on averages from 50 analyses of ROs, 11 analyses of MDOs and 43 analyses of MGOs from ships operating in northern EU seas.

Fuel type	Properties			
Residual Oil (RO)	Density at 15 °C (kg/m^3):	0,965	Viscosity at 50 °C (mm^2/s):	204
(Viscosity 50 - 810)	Effective heating value (MJ/kg):	40,96		
	Carbon (%):	86,61	Hydrogen (%):	11,34
	Sulphur (%):	1,91	Nitrogen (%):	0,33
	Oxygen (%):	<0,1		
Marine Diesel Oil (MDO)	Density at 15 °C (kg/m^3):	0,900	Viscosity at 50 °C (mm^2/s):	19,3
(Viscosity 5,5 - 50)	Effective heating value (MJ/kg):	42,19		
	Carbon (%):	86,68	Hydrogen (%):	12,62
	Sulphur (%):	0,93	Nitrogen (%):	<0,1
	Oxygen (%):	<0,1		
Marine Gas Oil (MGO)	Density at 15 °C (kg/m^3):	0,852	Viscosity at 50 °C (mm^2/s):	3,1
(Viscosity 1 - 5,5)	Effective heating value (MJ/kg):	42,65		
	Carbon (%):	86,74	Hydrogen (%):	13,23
	Sulphur (%):	0,23	Nitrogen (%):	<0,1
	Oxygen (%):	<0,1		

C.1.3 Engine size, age, condition and power output

In general, emission correlations with engine size (MCR kW) age, condition (service intervals) and power output are difficult to isolate from a limited dataset of measurements on board operating ships. Since considerable variation and spread can exist in the data, the significance of a suspected correlation can often prove questionable.

USCG Comment #4:

Volume 5 Part 1 – Attachment 2-1 General Conformity Page 3-1 and Appendix A: The document indicates that the concrete caissons will be assembled and towed from Philadelphia. The Philadelphia metropolitan area is also nonattainment for ozone and PM2.5 and any emissions associated with the construction and transportation of the caissons will require a separate general conformity applicability determination for the portion of the emissions occurring within the Philadelphia nonattainment areas. Additionally, if the caissons will be traversing New Jersey state waters the general conformity determination will have to include emissions within those waters. Please note that portions of New Jersey are within the Philadelphia ozone and PM2.5 nonattainment areas, and portions of New Jersey lie within the New York metropolitan ozone and PM2.5 nonattainment areas. Please quantify direct and indirect emissions and submit separate general conformity applicability determinations for the portions of the project occurring within the Philadelphia and New Jersey nonattainment areas, as appropriate.

Response:

Response to this data request will be provided on or before January 31, 2009.

USCG Comment #5:

Volume 5 Part 1 – Attachment 2-1 General Conformity Page 3-3: Further analysis is needed to determine the extent of changes in emissions associated with the Ambrose Channel dredging due to the Safe Harbor Energy Project and to include these in the Safe Harbor Energy conformity determination. Review the original assumptions associated with the transport of dredged material from the Ambrose Channel site and any impacts the re-routing of ships would have on the Corps' conformity determination for the Harbor Deepening project, which is being monitored through the Harbor Air Management Plan. Consultation with Army Corps may be necessary. Please submit the results of the additional analysis.

Response:

ASIG has requested a copy of the most recent Harbor Management Plan as well as a meeting with the U.S. Army Corps of Engineers to discuss this comment. After consultation with USACE, a response will be provided.

USCG Comment #6:

Volume 5 Part 1 – Attachment 2-1 General Conformity Page 5-1: The New York State Implementation Plan (SIP) does not specify emission budgets for the proposed Project; therefore, the conclusion that "...Safe Harbor Energy will not cause emissions budgets specified in SIPs to be exceeded..."does not appear to be correct. Please consult with the New York State Department of Environmental Conservation to evaluate incorporating project emissions into the SIP emission inventories as a method of demonstrating conformity or identify other methods to demonstrate compliance with the SIP. Provide documentation of NYSDEC approval of project emissions in the SIP emissions budget or additional information on how compliance will be achieved.

Response:

The Project has requested a meeting with EPA to discuss this comment. After consultation with EPA, and if necessary NYSDEC, a response will be provided.

USCG Comment #7:

Volume 5 Part 1 – Attachment 2-3: Provide a full graphic of the dispersion of water vapor (fog) that may be generated from the vaporization of LNG to natural gas during the summer months. (Attachment 2-3 shows model results but no graphics.)

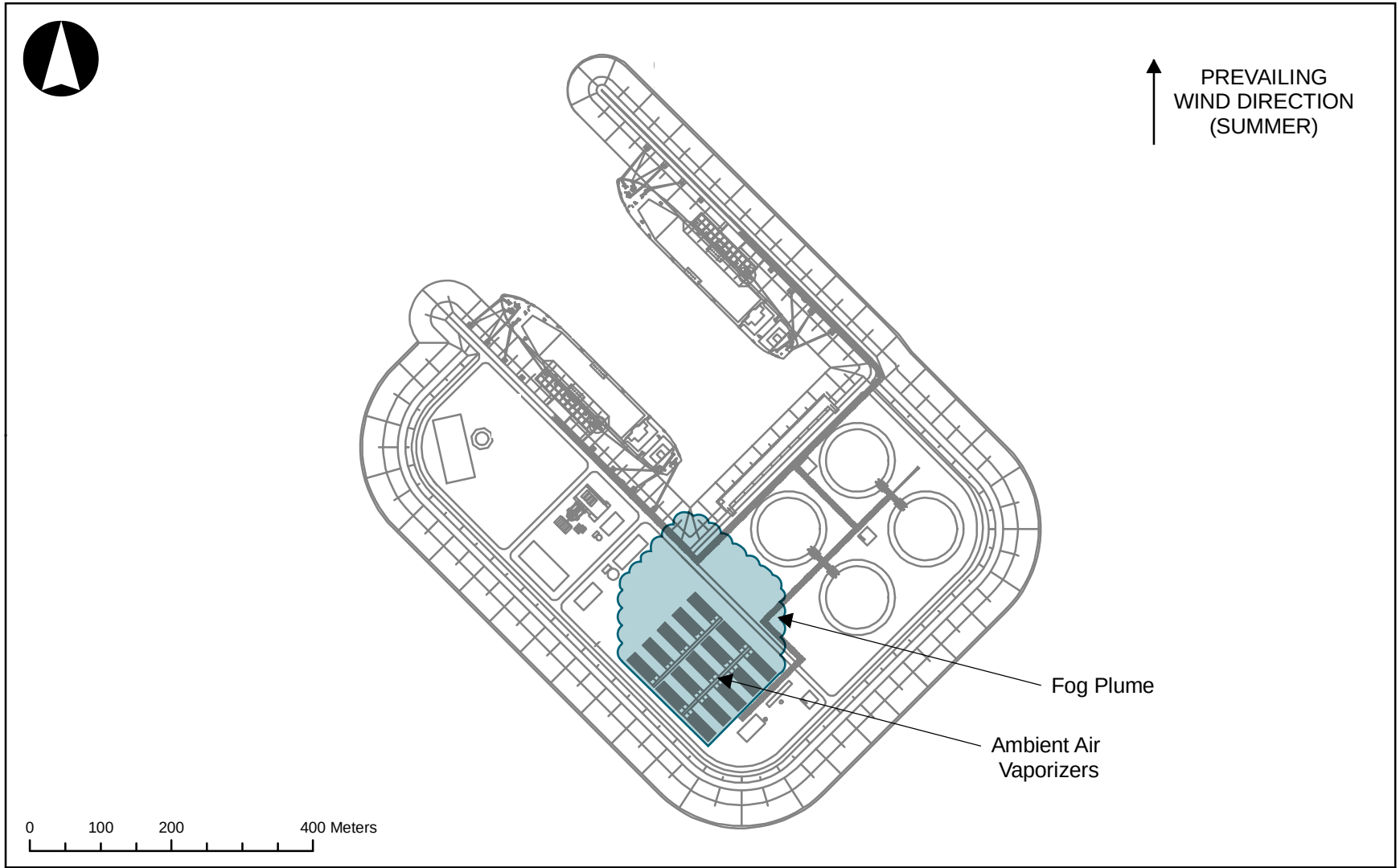
Response:

A graphic depiction of the seasonal average fog dispersion for the summer months (worst case season) is provided in Attachment 7-1.

As stated in Volume Five, Part One, Supplemental Report, Section 2.3.2: "[the worst case] fogging condition is predicted to occur for a distance of no more than 200 to 300 feet from the point of discharge…During humid summer conditions, if fogging does occur, it is not predicted to travel a distance that would impact vessels or navigation because it would not extend significantly off the island."

Attachment 7-1

- PHAST Model Predicted Fog Plume from the Ambient Air Vaporizers (Summer Conditions)



Safe Harbor Energy
A Project of the Atlantic Sea Island Group, LLC

Atlantic Sea Island Group LLC
Safe Harbor Energy

PHAST Model Predicted
Fog Plume from the Ambient Air Vaporizers
(Summer Conditions)

October 2008

Figure Q7

TETRA TECH EC, INC

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USCG Comment #8:

Volume 2 Exhibit X Air Permit Application Appendix B.2 – Calculation Spreadsheets, LNG Unloading from Vessels: A footnote c under "[l]oad due to hoteling (kW)" indicates that ASIG relied on Broadwater's Resource Report No. 9, Table 13, dated January 2006 to determine the load due to hoteling. Please note that Broadwater has since revised Table 13 with Table 13a submitted to EPA on May 3, 2006. For any data from the Broadwater Table 13 that ASIG relied on and has since changed, ASIG should update and resubmit the information.

Response:

As shown in the referenced spreadsheet (Attachment 8-1), the only values to which footnote "c" was applicable were the approximate electrical loads associated with hoteling. Broadwater did not change these loads between Table 13 and Table 13a, and therefore no update is necessary. Attachment 8-2 includes Table 13 and Table 13a submitted by Broadwater.

Attachment 8-1

- Volume Two, Exhibit X Air Permit Application, Appendix B.1 Explanation of Calculations, pages B-6 and B-7

- Volume Two, Exhibit X Air Permit Application, Appendix B.2 Calculation Spreadsheets, LNG Unloading from Vessels

B.7. LNG Unloading (Vessel Emissions)

The "LNG Unloading from Vessels" worksheet identifies short-term emissions and exhaust gas characteristics from the various LNG vessel types. As shown in Appendix A5 and discussed in Section 3.2 of this application, there are four different LNG tanker types considered, three of which are capable of firing either oil or gas to generate electricity.

All vessels will be unloading at a rate of 14,000 m^3 LNG/hr, which is estimated to require approximately 4,300 kW of electrical power.

B.7.1 Fuel Consumption and Emissions

Entec (2002)[2] developed fuel consumption factors and emission factors (all expressed in g/kWh) for oil-fired marine vessels, and these data were also used by Starcrest (2003) to develop a marine vessel emissions inventory for the New York/Northern New Jersey/Long Island nonattainment area.[9] Entec's report included separate factors for main engines (underway), main engines (in port/maneuvering), and auxiliary engines; factors for main engines (in port/maneuvering) from Table 2.9 of that report were used for the ST/RO, MSD/DO, and GT/DO cases. For the SSD/RO case, the main engines are mechanical-drive engines, and therefore factors for auxiliary engines were used (Table 2.10 of the Entec report). Because the Entec report did not include CO emissions, CO emission factors from the Starcrest report (Table D.9) were used. Emission factors for total HAP and formaldehyde were calculated based on fuel consumption per kWh and emission factors from EPA's AP-42 publication, as shown in the worksheets labeled "HAP Emission Factor Calculation Sheet – Residual Oil Combustion (External)", "HAP Emission Factor Calculation Sheet – Oil-Fired Turbines", and the previously mentioned "HAP Emission Factor Calculation Sheet – Large Stationary Diesel Engines".

For the cases in which the ST, MSD, and GT technologies fire gas instead of oil, fuel consumption (g/kWh) was estimated on an equivalent heat-content basis: for example, in the case of the ST, Entec estimated fuel consumption of 336 g/kWh for the oil-fired case. The fuel consumption for the gas-fired case was estimated based on the relative heat contents of the oil (17,608 Btu/lb) and gas (23,544 Btu/lb): i.e.,

$$\text{Fuel consumption} = (336\ \text{g/kWh})(17{,}608\ \text{Btu/lb})/(23{,}544\ \text{Btu/lb}) = 251\ \text{g/kWh}. \qquad \text{(B-7)}$$

For the GT/gas case, a NO_x emissions factor of 2 g/kWh was used, based on data for Wärtsilä 50 DF (see Appendix A6). For the other gas-fired cases, emission factors in g/kWh were calculated based on emission factors from EPA's AP-42 publication and the calculated fuel consumption per kWh.

Emissions of total HAP and formaldehyde were calculated based on data from EPA's AP-42 publication (as shown in the worksheet labeled "HAP Emission Factor Calculation Sheet – Natural Gas-Fired Turbines" and the previously referenced worksheet labeled "HAP Emission Factor Calculation Sheet – Natural Gas Combustion (External)". For the MSD/gas case, AP-42 does not provide HAP emission factors, and HAP emissions were conservatively assumed to be the same as for the MSD/oil case.

For all technology/fuel combinations, SO_2 emissions were conservatively calculated based on 100% conversion of the maximum sulfur content to SO_2.

B.7.2 Exhaust Gas Parameters

Exhaust gas parameters were calculated based on the total loads that the fuel-burning sources would actually be operating at; i.e., loads associated with both unloading and hotelling. Estimates of hotelling

[9] Starcrest Consulting Group (2003), "The New York, Northern New Jersey, Long Island Nonattainment Area Commercial Marine Vessel Emissions Inventory," April.

loads shown on the "LNG Unloading from Vessels" worksheet were taken from data presented for the Broadwater project.[10]

Exit temperatures for the steam turbine cases (ST/RO and ST/gas) are based on manufacturer's data (Mitsubishi Heavy Industries) provided in the air permit application for the Northeast Gateway Energy Bridge™ deepwater LNG port,[11] for the case of 50%-of-full-speed load (which is conservative, given that the corresponding fuel firing rates of 1,753 kg/h oil and 1,458 kg/h gas are lower than the firing rates of 2,083 kg/h oil and 1,558 kg/h gas that correspond to the total load of 6,200 kW for this project). The exit temperature of 762 °F for the medium-speed diesel cases (MSD/DO and MSD/gas) is from the air dispersion modeling protocol for the Neptune deepwater LNG port. For the SSD/RO, the exit temperature is that of an auxiliary diesel identified in the Northeast Gateway Energy Bridge™ deepwater LNG port application[11]—i.e., a turbocharged MAN/B&W L32/40 diesel operating at 75% load. For the gas turbine cases (GT/DO and GT/gas), the exit temperature of 520 °F is from an American Society of Mechanical Engineers (ASME) technical paper titled "A Fully Enhanced Gas Turbine for Surface Ships",[12] for the case involving thermal recuperation and partial load. (This is likely to be conservative; the designer of a GT configuration for an LNG vessel stated that heat recuperation was actually not that extensive and that stack temperatures are higher than this.)

Exhaust flowrates for the steam turbine cases were calculated based on mass exhaust flowrates (e.g., see Equation B-5) identified in the manufacturer's data for 50%-of-full-speed load, based on the listed exit temperature and assuming a stack gas molecular weight of 29 for exhaust from the oil-fired case and a stack gas molecular weight of 28 for exhaust from the gas-fired case (calculated flowrates were rounded to two significant digits). Exhaust flowrates for the medium-speed diesel case were estimated based on the estimated total load (7,300 kW) using the identified fuel consumption and using the F-factor (see Section B.1.1), with 10% excess O_2 (dry) at the stack (based on data for the Wärtsilä 50 DF in Appendix A6, showing air/fuel ratios of approximately 2x stoichiometric). For example, for the MSD/DO case, where fuel consumption is 223 g/kWh (see Section B.6.1 for derivation), fuel heating value is 18,136 Btu/lb (see Section B.1.1 for reference information), F_d = 9,875 dscf/MMBtu (see Section B.1.1 and "Fuel Composition" worksheet):

$$\text{Total heat input} = (7{,}300\ \text{kW})(223\ \text{g/kWh})(18{,}136\ \text{Btu/lb})(\text{lb}/453.6\ \text{g}) = 65.1\ \text{MMBtu/hr}$$

$$\text{Flow} = (65.1\ \text{MMBtu/hr})(9{,}875\ \text{dscf/MMBtu})\left(\frac{20.9}{(20.9-10)}\right)(\text{hr}/60\ \text{min}) = 20{,}540\ \text{dscfm} \qquad \text{(B-8)}$$

Actual wet flow was calculated by adjusting for the stack exit temperature and the moisture content; for 10% excess O_2 (dry), a wet-volume-to-dry-volume ratio of 1.13 (exhaust moisture content of 12.5%) was estimated:

$$(20{,}540\ \text{dscfm}) \times \frac{460 + 762}{460 + 68} \times 1.13 \approx 54{,}000\ \text{acfm (wet)}. \qquad \text{(B-9)}$$

Exhaust flowrates for the SSD/RO case were estimated based on the MAN/B&W L32/40 data mentioned above, which identify a combined consumption of fuel and air of 10 kg/kWh. Corresponding mass flow of the exhaust associated with the total load of 7,300 kW is then 73,000 kg/h = 1,217 kg/min, which was

[10] Broadwater (2006), "Resource Report No. 9 – Air and Noise Quality for a Project to Construct and Operate a Liquefied Natural Gas Receiving Terminal in Long Island Sound, Long Island, New York," January, Appendix B, Table 13.

[11] Tetra Tech EC Inc. (2006)," Northeast Gateway Energy Bridge™ Deepwater Port Project - Minor Source
Air Permit Application," submitted by Northeast Gateway Energy Bridge LLC to EPA Region I, February, Appendix B.

[12] J. Janes (1996), "A Fully Enhanced Gas Turbine for Surface Ships," ASME paper 96-GT-527 presented at the International Gas Turbine And Aeroengine Congress & Exhibition (Birmingham, U.K.), June 10-12 (available from the internet at http://www.energy.ca.gov/papers/JANES-ASME-PAPER.PDF).

LNG Unloading from Vessels

Operational description: LNG will be unloaded from LNG carriers at a rate of 14,000 m^3/hr, with the LNG carriers providing power (estimated power demand 4300 kW). Emissions from the carriers will depend on the type of carrier. Of existing LNG carriers (approximately 200), almost all utilize steam turbines (ST) for which steam is generated using residual oil (RO)-fired boilers, although some carriers also have the capability of firing gas. However, over 100 LNG carriers are currently on order (and would be operational by the time that this project is operational), and most of these utilize either dual-fueled medium-speed diesel electric (MSD, DFDE) vessels that can fire LNG boil-off or distillate oil (DO), and RO-fired mechanical-drive slow-speed diesels (SSD) that would be required to use auxiliary gensets rather than main engines for unloading. Gas turbine (GT) designs are also being considered.

Unloading rate:	14,000	m^3/hr
Power demand:	4,300	kW

	ST/RO[a]	ST/gas[a]	MSD/DO[a]	MSD/gas[a]	SSD/RO[a]	GT/DO[a]	GT/gas[a]
Fuel consumption (g/kWh)	336	251	223	172	217	319	246
	Emission Factors (g/kWh)						
NO_x	1.7	1.1	10.6	2.0	14.7	2.9	1.9
VOC	0.3	0.03	1.5	0.8	0.4	0.5	0.012
CO	0.12	0.5	1.75	4.7	1.59	0.15	0.5
SO_2 (max)[b]	10.1	0.003	6.7	0.002	6.5	9.6	0.003
PM	2.4	0.04	0.9	0.9	0.8	0.5	0.04
Ammonia	0	0	0	0	0	0	0
HAP (total)	0.010	0.011	0.03	0.03	0.02	0.010	0.006
Formaldehyde	0.002	4.4E-04	4.1E-04	4.1E-04	4.0E-04	0.002	0.004
Load due to hotelling (kW)[c]	1,900	1,900	3,000	3,000	3,000	2,300	2,300
Total load (kW)	6,200	6,200	7,300	7,300	7,300	6,600	6,600
Stack exit temperatures (^oF):[d]	316	316	762	762	590	520	520
Stack exit flowrates (acfm):[d]	22,000	23,000	54,000	47,000	73,400	99,000	87,000

[a]See Appendix B, Section B.6.1.

[b]SO_2 emission factor is based on fuel sulfur content (see Parameters worksheet)

[c]From Broadwater, Resource Report No. 9, Table 13, January 2006.

[d]See Appendix B, Section B.6.2.

EMISSIONS ASSOCIATED WITH UNLOADING (4300 kW)

								Worst case	
Short-term emiss. (g/s)	ST/RO	ST/gas	MSD/DO	MSD/gas	SSD/RO	GT/DO	GT/gas	oil	gas
NO_x	2.0	1.3	12.7	2.4	17.6	3.5	2.2	17.6	2.4
VOC	0.36	0.04	1.79	0.97	0.48	0.60	0.01	1.79	0.97
CO	0.14	0.6	2.1	5.6	1.9	0.2	0.6	2.1	5.6
SO_2	12.0	0.0	8.0	0.0	7.8	11.4	0.0	12.0	0.0
PM	2.9	0.05	1.1	1.1	1.0	0.6	0.05	2.9	1.1
Ammonia	0	0	0	0	0	0	0	0	0
HAP (total)	1.2E-02	1.3E-02	3.1E-02	3.1E-02	3.0E-02	1.2E-02	7.1E-03	3.1E-02	3.1E-02
Formaldehyde	2.1E-03	5.2E-04	4.9E-04	4.9E-04	4.8E-04	2.5E-03	4.9E-03	2.5E-03	4.9E-03

								Worst case	
Short-term emiss. (lb/hr)	ST/RO	ST/gas	MSD/DO	MSD/gas	SSD/RO	GT/DO	GT/gas	oil	gas
NO_x	16.1	10.4	100.5	19.0	139.4	27.5	17.6	139.4	19.0
VOC	2.8	0.3	14.2	7.7	3.8	4.7	0.12	14.22	7.67
CO	1.14	4.6	16.6	44.5	15.1	1.4	4.5	16.6	44.5
SO_2	95.6	0.03	63.4	0.02	61.7	90.7	0.03	95.6	0.0
PM	22.8	0.42	8.5	8.5	7.6	4.7	0.36	22.75	8.53
Ammonia	0	0	0	0	0	0	0	0	0
HAP (total)	0.096	0.10	0.24	0.24	0.24	0.092	0.056	2.4E-01	2.4E-01
Formaldehyde	0.016	0.004	0.004	0.004	0.004	0.020	0.039	2.0E-02	3.9E-02

Attachment 8-2

- Broadwater Resource Report Nine, Table 13, dated January 2006

- Broadwater Resource Report Nine, Table 13a, submitted to EPA on May 3, 2006

Table 13

SUMMARY OF EMISSION RATES FOR LNG CARRIERS OF VARIOUS CARGO CAPACITY AND LOADING RATE WHILE AT THE FSRU

Daily Natural Gas Delivery	1	bcf/day	Estimated average daily natural gas delivery rate.
	21,095	Mg/day	Calculated from ideal gas law using standard temperature and pressure.
Annual LNG Delivery Rate by Mass	7,700,000	metric tons/yr	Maximum annual LNG delivery to FSRU
	7,700,051	Mg/yr	
LNG Density	470	kg/m^3	Design data from RR13
LNG Annual Delivery Rate by Volume	16,383,086	m^3/yr	Calculated from Annual LNG Delivery Rate by Mass and LNG Density

Vessel Type	Vessel Size (m^3)	LNG Loading (m^3/hr)	Annual Vessel Dockings (#/yr)	Vessel Duration at FSRU: LNG Loading (hr)	Vessel Duration at FSRU: No Loading (hr)	Power Supplied by Engines[1]: LNG Pumps (kW)	Power Supplied by Engines[1]: Other Equip. (kW)	Fuel Use by Vessel at FSRU[2,3] (tons)	Maximum Hourly Emissions[4] (lb/hr): NO_x	VOC	CO	CO_2	SO_2	PM_{10} ($PM_{2.5}$)	Maximum Hourly Emissions with No Loading[5] (lb/hr): SO_2	PM_{10} ($PM_{2.5}$)	Average Hourly Emission Over 24-Hour Period[6] (lb/hr): SO_2	PM_{10} ($PM_{2.5}$)	Annual Emissions - LNG Loading (tpy): NO_x	VOC	CO	CO_2	SO_2	PM_{10} ($PM_{2.5}$)	Annual Emissions - No Loading (tpy): NO_x	VOC	CO	CO_2	SO_2	PM_{10} ($PM_{2.5}$)	Annual Emissions - Total (tpy): NO_x	VOC	CO	CO_2	SO_2	PM_{10} ($PM_{2.5}$)
Existing																																				
Conventional LNGC	125,000	10,000	132	12.5	8	4,500	1,900	32	30	0.4	1.7	13,489	230	11	115	3.1	158	7	24	0.3	1.4	11,128	190	9	5	0.1	0.3	2,114	36	1.7	29	0.4	1.7	13,242	226	10
Heavy Fuel Oil (2.7%S)		13,000	132	9.6	8	5,750	1,900	30	35	0.5	2.0	16,123	463	13	115	3.1	224	6	22	0.3	1.3	10,232	174	8	5	0.1	0.3	2,114	36	1.7	27	0.4	1.5	12,346	210	10
Steam turbine propulsion		15,000	132	8.3	8	6,650	1,900	29	40	0.6	2.3	18,020	517	14	115	3.1	218	6	22	0.3	1.2	9,911	169	8	5	0.1	0.3	2,114	36	1.7	26	0.4	1.5	12,025	205	9
Conventional LNGC	140,000	10,000	118	14.0	8	4,500	1,900	35	30	0.4	1.7	13,489	387	11	115	3.1	264	7	24	0.3	1.4	11,142	190	9	4	0.1	0.2	1,890	32	1.5	29	0.4	1.6	13,032	222	10
Heavy Fuel Oil (2.7%S)		13,000	118	10.8	8	5,750	1,900	33	35	0.5	2.0	16,123	463	13	115	3.1	246	7	23	0.3	1.3	10,244	175	8	4	0.1	0.2	1,890	32	1.5	27	0.4	1.5	12,134	207	10
Steam turbine propulsion		15,000	118	9.3	8	6,650	1,900	32	40	0.6	2.3	18,020	517	14	115	3.1	240	7	22	0.3	1.2	9,923	169	8	4	0.1	0.2	1,890	32	1.5	26	0.4	1.5	11,813	201	9
Conventional LNGC	160,000	10,000	103	16.0	8	4,500	1,900	40	30	0.4	1.7	13,489	387	11	115	3.1	297	8	24	0.3	1.4	11,115	189	9	4	0.1	0.2	1,650	28	1.3	28	0.4	1.6	12,764	217	10
Heavy Fuel Oil (2.7%S)		13,000	103	12.3	8	5,750	1,900	37	35	0.5	2.0	16,123	463	13	115	3.1	276	8	22	0.3	1.3	10,220	174	8	4	0.1	0.2	1,650	28	1.3	26	0.4	1.5	11,869	202	9
Steam turbine propulsion		15,000	103	10.7	8	6,650	1,900	36	40	0.6	2.3	18,020	517	14	115	3.1	268	7	22	0.3	1.2	9,899	169	8	4	0.1	0.2	1,650	28	1.3	25	0.4	1.4	11,549	197	9
Vessels On-Order (in-service about 2008)																																				
New Design LNGC	160,000	10,000	103	16.0	8	4,500	2,700	29	312	9.5	25.2	10,825	185	26	69	9.8	146	21	257	7.8	20.8	8,920	152	21	48	1.5	3.9	1,673	29	4.0	306	9.3	24.7	10,593	181	25
Heavy Fuel Oil (2.7%S)		13,000	103	12.3	8	5,750	2,700	27	366	11.2	29.6	12,705	217	31	69	9.8	134	19	232	7.1	18.8	8,053	137	19	48	1.5	3.9	1,673	29	4.0	280	8.6	22.7	9,725	166	23
Slow Speed Diesel		15,000	103	10.7	8	6,650	2,700	26	405	12.4	32.8	14,058	240	34	69	9.8	130	18	223	6.8	18.0	7,723	132	19	48	1.5	3.9	1,673	29	4.0	271	8.3	21.9	9,395	160	23
New Large LNGC	215,000	10,000	77	21.5	8	4,500	3,000	40	325	9.9	26.3	11,276	192	27	77	10.8	180	25	269	8.2	21.8	9,334	159	22	40	1.2	3.2	1,389	24	3.3	309	9.4	25.0	10,723	183	26
Heavy Fuel Oil (2.7%S)		13,000	77	16.5	8	5,750	3,000	36	379	11.6	30.7	13,156	224	32	77	10.8	179	25	242	7.4	19.5	8,377	143	20	40	1.2	3.2	1,389	24	3.3	282	8.6	22.8	9,766	167	23
Slow Speed Diesel		15,000	77	14.3	8	6,650	3,000	35	418	12.8	33.8	14,509	247	35	77	10.8	173	24	231	7.0	18.7	8,007	137	19	40	1.2	3.2	1,389	24	3.3	271	8.3	21.9	9,396	160	23
Concept Vessels (in-service beyond 2010)																																				
New Very Large LNGC	250,000	10,000	66	25.0	8	4,500	3,200	47	334	10.2	27.0	11,577	197	28	82	11.6	197	28	275	8.4	22.3	9,551	163	23	37	1.1	3.0	1,270	22	3.1	312	9.5	25.2	10,821	185	26
Heavy Fuel Oil (2.7%S)		13,000	66	19.2	8	5,750	3,200	42	388	11.8	31.4	13,457	229	32	82	11.6	200	28	246	7.5	19.9	8,540	146	21	37	1.1	3.0	1,270	22	3.1	283	8.6	22.9	9,810	167	24
Slow Speed Diesel[7]		15,000	66	16.7	8	6,650	3,200	41	427	13.0	34.5	14,810	253	36	82	11.6	200	28	235	7.2	19.0	8,145	139	20	37	1.1	3.0	1,270	22	3.1	272	8.3	22.0	9,416	161	23
New Very Large LNGC	250,000	10,000	66	25.0	8	4,500	2,300	n/a	20	0.13	5.0	6,732	0.04	0.40	0.01	0.14	0.04	0.40	16	0.11	4	5,554	0.03	0.33	1.7	0.01	0.4	601	0.003	0.036	18	0.12	4.6	6,155	0.04	0.37
LNG fuel only		13,000	66	19.2	8	5,750	2,300	n/a	23	0.15	5.9	7,970	0.05	0.48	0.01	0.14	0.04	0.41	15	0.10	4	5,058	0.03	0.30	1.7	0.01	0.4	601	0.003	0.036	16	0.11	4.2	5,659	0.03	0.34
Gas Turbine Propulsion[8,9]		15,000	66	16.7	8	6,650	2,300	n/a	26	0.17	6.6	8,861	0.05	0.53	0.01	0.14	0.04	0.41	14	0.09	4	4,873	0.03	0.29	1.7	0.01	0.4	601	0.003	0.036	16	0.10	4.1	5,474	0.03	0.33

Notes:

1. Based on data supplied in Ref 4. LNG Pumps operate only during "LNG Loading". Other Equip. operates during "LNG Loading" and "No Loading"
2. Steam Turbine fuel use based on engine flow rate of 305 g/kW-hr (Ref. 11, Table 2.8). Steady operation while unloading is consistent with "at sea" operations.
3. Slow speed diesel fuel use based on fuel flow rate of 195 g/kW-hr (Ref. 11, Table 2.8). Steady operation while unloading is consistent with "at sea" operations.
4. Maximum hourly emission rate based on operation of vessel auxiliary engines needed to power LNG Pumps and Other Equipment.
5. Maximum hourly emission rate based on operation of vessel auxiliary engines needed to power only Other Equipment.
6. Weighted values based on emissions during Loading and No Loading periods.
7. New Very Large LNGC vessel assumed to use slow speed diesel on HFO only. Vessel will have a LNG reliquefaction plant on-board, no boil off gas available for propulsion.
8. New Very Large LNGC vessel assumed to use gas turbine capable of 22MW generation. No vessels of this type under design yet; specifications speculative only. No reliquefaction plant used.
9. Fuel rate of gas turbines estimated at 9,000 Btu/kW-hr.

20060811500 9 Received FERC OSEC 08/11/2006 11:08:00 AM Docket# CP06-54-000, ET AL.

Table 13a

SUMMARY OF EMISSION RATES FOR LNG CARRIERS OF VARIOUS CARGO CAPACITY AND LOADING RATE WHILE AT THE FSRU

Daily Natural Gas Delivery	1	bcf/day	Estimated average daily natural gas delivery rate.
	21,095	Mg/day	Calculated from ideal gas law using standard temperature and pressure.
Annual LNG Delivery Rate by Mass	7,700,000	metric tons/yr	Maximum annual LNG delivery to FSRU
	7,700,051	Mg/yr	
LNG Density	470	kg/m^3	Design data from RR13
LNG Annual Delivery Rate by Volume	16,383,086	m^3/yr	Calculated from Annual LNG Delivery Rate by Mass and LNG Density

Pump Power requirements 2,816 ST vessel 138K m3

3,212 SSD reliq vessel, 260K m3

Vessel Type	Vessel Size (m^3)	LNG Loading Rate (m^3/hr)	Annual Vessel Dockings (#/yr)	Vessel Duration at FSRU: LNG Loading (hr)	Vessel Duration at FSRU: No Loading (hr)	Power Supplied by Engines[1]: LNG Pumps (kW)	Power Supplied by Engines[1]: Other Equip. (kW)	Fuel Use by Vessel at FSRU[2,3] (tons)	Maximum Hourly Emissions[4] (lb/hr): NO_x	VOC	CO	CO_2	SO_2	PM_{10} ($PM_{2.5}$)	Maximum Hourly Emissions with No Loading[5] (lb/hr): SO_2	PM_{10} ($PM_{2.5}$)	Average Hourly Emission Over 24-Hour Period[6] (lb/hr): SO_2	PM_{10} ($PM_{2.5}$)	Annual Emissions - LNG Loading (tpy) - Pumping and Ship Hoteling Subtotal: NO_x	VOC	CO	CO_2	SO_2	PM_{10} ($PM_{2.5}$)
Existing Vessel Population																								
Conventional LNGC	125,000	10,000	132	12.5	8	2,816	1,900	25	22	0.3	1.2	9,939	285	8	68	3.1	171	5	18.01	0.3	1.03	8,200	140	6
Heavy Fuel Oil (2.7%S)		13,000	132	9.6	8	3,661	1,900	23	26	0.4	1.5	11,720	337	9	68	3.1	158	5	16.34	0.2	0.93	7,438	127	6
Steam turbine propulsion		15,000	132	8.3	8	4,224	1,900	22	28	0.4	1.6	12,907	371	10	68	3.1	151	5	15.59	0.2	0.89	7,099	121	6
Conventional LNGC	140,000	10,000	118	14.0	8	2,816	1,900	27	22	0.3	1.2	9,939	285	8	68	3.1	189	6	18.03	0.3	1.03	8,210	140	6
Heavy Fuel Oil (2.7%S)		13,000	118	10.8	8	3,661	1,900	25	26	0.4	1.5	11,720	337	9	68	3.1	174	5	16.36	0.2	0.93	7,447	127	6
Steam turbine propulsion		15,000	118	9.3	8	4,224	1,900	24	28	0.4	1.6	12,907	371	10	68	3.1	167	5	15.61	0.2	0.89	7,107	121	6
Conventional LNGC	160,000	10,000	103	16.0	8	2,816	1,900	30	22	0.3	1.2	9,939	285	8	68	3.1	213	6	17.99	0.3	1.03	8,190	140	6
Heavy Fuel Oil (2.7%S)		13,000	103	12.3	8	3,661	1,900	28	26	0.4	1.5	11,720	337	9	68	3.1	195	6	16.32	0.2	0.93	7,429	127	6
Steam turbine propulsion		15,000	103	10.7	8	4,224	1,900	27	28	0.4	1.6	12,907	371	10	68	3.1	187	6	15.57	0.2	0.89	7,090	121	6
Vessel Design On-Order (Expected in-service 2008)																								
New Design LNGC	160,000	10,000	1	16.0	8	2,816	2,700	24	239	7.3	19.3	8,293	79	20	69	9.8	76	17	2	0.1	0.2	66	1	0
Heavy Fuel Oil (1.5%S)		13,000	1	12.3	8	3,661	2,700	21	276	8.4	22.3	9,564	92	23	69	9.8	70	15	2	0.1	0.1	59	1	0
Slow Speed Diesel		15,000	1	10.7	8	4,224	2,700	21	300	9.2	24.3	10,410	100	25	69	9.8	67	14	2	0.0	0.1	56	1	0
New Large LNGC	215,000	10,000	1	21.5	8	2,816	3,000	32	252	7.7	20.4	8,745	84	21	77	10.8	83	20	3	0.1	0.2	94	2	0
Heavy Fuel Oil (1.5%S)		13,000	1	16.5	8	3,661	3,000	29	289	8.8	23.3	10,015	96	24	77	10.8	90	20	2	0.1	0.2	83	1	0
Slow Speed Diesel		15,000	1	14.3	8	4,224	3,000	27	313	9.6	25.3	10,861	104	26	77	10.8	88	19	2	0.1	0.2	78	1	0
Concept Vessels In Serivce (beyond 2010)																								
New Very Large LNGC	250,000	10,000	1	25.0	8	3,212	3,200	40	278	8.5	22.5	9,641	92	23	82	11.6	92	23	3	0.1	0.3	121	2	0
Heavy Fuel Oil (1.5%S)		13,000	1	19.2	8	4,176	3,200	36	320	9.8	25.9	11,089	106	27	82	11.6	101	24	3	0.1	0.2	107	2	0
Slow Speed Diesel[7]		15,000	1	16.7	8	4,818	3,200	34	348	10.6	28.1	12,055	115	29	82	11.6	105	24	3	0.1	0.2	100	2	0
New Very Large LNGC	250,000	10,000	1	25.0	8	3,212	2,300	n/a	16	0.10	4.1	5,457	0.03	0.33	0.01	0.14	0.03	0.33	0	0.00	0	68	0.00	0.00
LNG fuel only		13,000	1	19.2	8	4,176	2,300	n/a	19	0.12	4.8	6,411	0.04	0.38	0.01	0.14	0.03	0.34	0	0.00	0	62	0.00	0.00
Gas Turbine Propulsion[8,9]		15,000	1	16.7	8	4,818	2,300	n/a	20	0.13	5.3	7,047	0.04	0.42	0.01	0.14	0.03	0.34	0	0.00	0	59	0.00	0.00

Notes:

1. Based on data supplied in Ref 4. LNG Pumps operate only during "LNG Loading". Other Equip. operates during "LNG Loading" and "No Loading"
2. Steam Turbine fuel use based on engine flow rate of 305 g/kW-hr (Ref. 11, Table 2.8). Steady operation while unloading is consistent with "at sea" operations.
3. Slow speed diesel fuel use based on fuel flow rate of 195 g/kW-hr (Ref. 11, Table 2.8). Steady operation while unloading is consistent with "at sea" operations.
4. Maximum hourly emission rate based on operation of vessel auxiliary engines needed to power LNG Pumps and Other Equipment.
5. Maximum hourly emission rate based on operation of vessel auxiliary engines needed to power only Other Equipment.
6. Weighted values based on emissions during Loading and No Loading periods.
7. New Very Large LNGC vessel assumed to use slow speed diesel on HFO only. Vessel will have a LNG reliquefaction plant on-board, no boil off gas available for propulsion.
8. New Very Large LNGC vessel assumed to use gas turbine capable of 22MW generation. No vessels of this type under design yet; specifications speculative only. No reliquefaction plant used.
9. Fuel rate of gas turbines estimated at 9,000 Btu/kW-hr.

USCG Comment #9:

Volume 2 Exhibit X Air Permit Application Appendix B.2 – Calculation Spreadsheets, Emissions Associated with Unloading (4300 kW): The worst-case hourly Oxides of Nitrogen (NOx) emissions for slow-speed diesel vessels burning residual oil is listed as 139.4 lb/hr. According to Broadwater's Resource Report No. 9, Table 13a, such a type of vessel would emit about 320 lb/hr of NOx instead of the 139.4 lb/hr. Similar discrepancies exist with the other criteria pollutants. Please explain these lower hourly figures used by ASIG. It should be noted that the first paragraph of this Appendix C page states that ASIG is also considering LNG vessels that are residual-oil fired mechanical-drive slow speed diesels that would be required to use auxiliary generator sets rather than main engines for unloading LNG. It is not clear from the application whether the 139.4 lb/hr NOx value and the other lower emissions are based on vessels that are using such auxiliary generator sets. If the listed lb/hr values are incorrect, the potential-to-emit (PTE) values must be reassessed and resubmitted.

Response:

The value of 320 lb/hr NO_x in Broadwater's Table 13a is identified as being "based on operation of vessel auxiliary engines needed to power LNG Pumps and Other Equipment," where the LNG pumps are identified as having a load of 4,176 kW and the "Other Equipment" refers to hoteling emissions, for which the load is identified as 3,200 kW. The value of 139.4 lb/hr NO_x in ASIG's air permit application (Volume Two Exhibit X, Appendix B.2) specifically refers to unloading emissions only. Per our discussion with EPA on April 4, 2006, hoteling emissions are instead addressed in the general conformity support document. This is the primary reason for the discrepancies mentioned.

In Section B.6.1 of Appendix B, we stated that "for the SSD/RO case, the main engines are mechanical-drive engines, and therefore factors for auxiliary engines were used," consistent with Broadwater.

The listed lb/hr values are correct, and the PTE values do not need to be reassessed or resubmitted.

Pertinent emissions calculation pages from Broadwater and Safe Harbor as well as notes from the April 4, 2006 meeting between EPA and ASIG are provided in Attachment 9-1.

Attachment 9-1

- Broadwater Resource Report No. 9, Table 13a, submitted to EPA on May 3, 2006
- Volume Two, Exhibit X Air Permit Application, Appendix B.2 Calculation Spreadsheets, LNG Unloading from Vessels
- Summary of Meeting Between Safe Harbor Energy and U.S. Environmental Protection Agency, April 4, 2006
- Volume Two, Exhibit X Air Permit Application, Appendix B.1 Explanation of Calculations, page B-6

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Table 13a

SUMMARY OF EMISSION RATES FOR LNG CARRIERS OF VARIOUS CARGO CAPACITY AND LOADING RATE WHILE AT THE FSRU

Daily Natural Gas Delivery	1	bcf/day	Estimated average daily natural gas delivery rate.
	21,095	Mg/day	Calculated from ideal gas law using standard temperature and pressure.
Annual LNG Delivery Rate by Mass	7,700,000	metric tons/yr	Maximum annual LNG delivery to FSRU
	7,700,051	Mg/yr	
LNG Density	470	kg/m^3	Design data from RR13
LNG Annual Delivery Rate by Volume	16,383,086	m^3/yr	Calculated from Annual LNG Delivery Rate by Mass and LNG Density

Pump Power requirements 2,816 ST vessel 138K m3

3,212 SSD reliq vessel, 260K m3

Vessel Type	Vessel Size (m^3)	LNG Loading Rate (m^3/hr)	Annual Vessel Dockings (#/yr)	Vessel Duration at FSRU: LNG Loading (hr)	Vessel Duration at FSRU: No Loading (hr)	Power Supplied by Engines[1]: LNG Pumps (kW)	Power Supplied by Engines[1]: Other Equip. (kW)	Fuel Use by Vessel at FSRU[2,3] (tons)	Maximum Hourly Emissions[4] (lb/hr): NO_x	VOC	CO	CO_2	SO_2	PM_{10} ($PM_{2.5}$)	Maximum Hourly Emissions with No Loading[5] (lb/hr): SO_2	PM_{10} ($PM_{2.5}$)	Average Hourly Emission Over 24-Hour Period[6] (lb/hr): SO_2	PM_{10} ($PM_{2.5}$)	Annual Emissions - LNG Loading (tpy) - Pumping and Ship Hoteling Subtotal: NO_x	VOC	CO	CO_2	SO_2	PM_{10} ($PM_{2.5}$)
Existing Vessel Population																								
Conventional LNGC	125,000	10,000	132	12.5	8	2,816	1,900	25	22	0.3	1.2	9,939	285	8	68	3.1	171	5	18.01	0.3	1.03	8,200	140	6
Heavy Fuel Oil (2.7%S)		13,000	132	9.6	8	3,661	1,900	23	26	0.4	1.5	11,720	337	9	68	3.1	158	5	16.34	0.2	0.93	7,438	127	6
Steam turbine propulsion		15,000	132	8.3	8	4,224	1,900	22	28	0.4	1.6	12,907	371	10	68	3.1	151	5	15.59	0.2	0.89	7,099	121	6
Conventional LNGC	140,000	10,000	118	14.0	8	2,816	1,900	27	22	0.3	1.2	9,939	285	8	68	3.1	189	6	18.03	0.3	1.03	8,210	140	6
Heavy Fuel Oil (2.7%S)		13,000	118	10.8	8	3,661	1,900	25	26	0.4	1.5	11,720	337	9	68	3.1	174	5	16.36	0.2	0.93	7,447	127	6
Steam turbine propulsion		15,000	118	9.3	8	4,224	1,900	24	28	0.4	1.6	12,907	371	10	68	3.1	167	5	15.61	0.2	0.89	7,107	121	6
Conventional LNGC	160,000	10,000	103	16.0	8	2,816	1,900	30	22	0.3	1.2	9,939	285	8	68	3.1	213	6	17.99	0.3	1.03	8,190	140	6
Heavy Fuel Oil (2.7%S)		13,000	103	12.3	8	3,661	1,900	28	26	0.4	1.5	11,720	337	9	68	3.1	195	6	16.32	0.2	0.93	7,429	127	6
Steam turbine propulsion		15,000	103	10.7	8	4,224	1,900	27	28	0.4	1.6	12,907	371	10	68	3.1	187	6	15.57	0.2	0.89	7,090	121	6
Vessel Design On-Order (Expected in-service 2008)																								
New Design LNGC	160,000	10,000	1	16.0	8	2,816	2,700	24	239	7.3	19.3	8,293	79	20	69	9.8	76	17	2	0.1	0.2	66	1	0
Heavy Fuel Oil (1.5%S)		13,000	1	12.3	8	3,661	2,700	21	276	8.4	22.3	9,564	92	23	69	9.8	70	15	2	0.1	0.1	59	1	0
Slow Speed Diesel		15,000	1	10.7	8	4,224	2,700	21	300	9.2	24.3	10,410	100	25	69	9.8	67	14	2	0.0	0.1	56	1	0
New Large LNGC	215,000	10,000	1	21.5	8	2,816	3,000	32	252	7.7	20.4	8,745	84	21	77	10.8	83	20	3	0.1	0.2	94	2	0
Heavy Fuel Oil (1.5%S)		13,000	1	16.5	8	3,661	3,000	29	289	8.8	23.3	10,015	96	24	77	10.8	90	20	2	0.1	0.2	83	1	0
Slow Speed Diesel		15,000	1	14.3	8	4,224	3,000	27	313	9.6	25.3	10,861	104	26	77	10.8	88	19	2	0.1	0.2	78	1	0
Concept Vessels In Serivce (beyond 2010)																								
New Very Large LNGC	250,000	10,000	1	25.0	8	3,212	3,200	40	278	8.5	22.5	9,641	92	23	82	11.6	92	23	3	0.1	0.3	121	2	0
Heavy Fuel Oil (1.5%S)		13,000	1	19.2	8	4,176	3,200	36	320	9.8	25.9	11,089	106	27	82	11.6	101	24	3	0.1	0.2	107	2	0
Slow Speed Diesel[7]		15,000	1	16.7	8	4,818	3,200	34	348	10.6	28.1	12,055	115	29	82	11.6	105	24	3	0.1	0.2	100	2	0
New Very Large LNGC	250,000	10,000	1	25.0	8	3,212	2,300	n/a	16	0.10	4.1	5,457	0.03	0.33	0.01	0.14	0.03	0.33	0	0.00	0	68	0.00	0.00
LNG fuel only		13,000	1	19.2	8	4,176	2,300	n/a	19	0.12	4.8	6,411	0.04	0.38	0.01	0.14	0.03	0.34	0	0.00	0	62	0.00	0.00
Gas Turbine Propulsion[8,9]		15,000	1	16.7	8	4,818	2,300	n/a	20	0.13	5.3	7,047	0.04	0.42	0.01	0.14	0.03	0.34	0	0.00	0	59	0.00	0.00

Notes:

1. Based on data supplied in Ref 4. LNG Pumps operate only during "LNG Loading". Other Equip. operates during "LNG Loading" and "No Loading"
2. Steam Turbine fuel use based on engine flow rate of 305 g/kW-hr (Ref. 11, Table 2.8). Steady operation while unloading is consistent with "at sea" operations.
3. Slow speed diesel fuel use based on fuel flow rate of 195 g/kW-hr (Ref. 11, Table 2.8). Steady operation while unloading is consistent with "at sea" operations.
4. Maximum hourly emission rate based on operation of vessel auxiliary engines needed to power LNG Pumps and Other Equipment.
5. Maximum hourly emission rate based on operation of vessel auxiliary engines needed to power only Other Equipment.
6. Weighted values based on emissions during Loading and No Loading periods.
7. New Very Large LNGC vessel assumed to use slow speed diesel on HFO only. Vessel will have a LNG reliquefaction plant on-board, no boil off gas available for propulsion.
8. New Very Large LNGC vessel assumed to use gas turbine capable of 22MW generation. No vessels of this type under design yet; specifications speculative only. No reliquefaction plant used.
9. Fuel rate of gas turbines estimated at 9,000 Btu/kW-hr.

LNG Unloading from Vessels

Operational description: LNG will be unloaded from LNG carriers at a rate of 14,000 m^3/hr, with the LNG carriers providing power (estimated power demand 4300 kW). Emissions from the carriers will depend on the type of carrier. Of existing LNG carriers (approximately 200), almost all utilize steam turbines (ST) for which steam is generated using residual oil (RO)-fired boilers, although some carriers also have the capability of firing gas. However, over 100 LNG carriers are currently on order (and would be operational by the time that this project is operational), and most of these utilize either dual-fueled medium-speed diesel electric (MSD, DFDE) vessels that can fire LNG boil-off or distillate oil (DO), and RO-fired mechanical-drive slow-speed diesels (SSD) that would be required to use auxiliary gensets rather than main engines for unloading. Gas turbine (GT) designs are also being considered.

Unloading rate:	14,000	m^3/hr
Power demand:	4,300	kW

	ST/RO[a]	ST/gas[a]	MSD/DO[a]	MSD/gas[a]	SSD/RO[a]	GT/DO[a]	GT/gas[a]
Fuel consumption (g/kWh)	336	251	223	172	217	319	246
	Emission Factors (g/kWh)						
NO_x	1.7	1.1	10.6	2.0	14.7	2.9	1.9
VOC	0.3	0.03	1.5	0.8	0.4	0.5	0.012
CO	0.12	0.5	1.75	4.7	1.59	0.15	0.5
SO_2 (max)[b]	10.1	0.003	6.7	0.002	6.5	9.6	0.003
PM	2.4	0.04	0.9	0.9	0.8	0.5	0.04
Ammonia	0	0	0	0	0	0	0
HAP (total)	0.010	0.011	0.03	0.03	0.02	0.010	0.006
Formaldehyde	0.002	4.4E-04	4.1E-04	4.1E-04	4.0E-04	0.002	0.004
Load due to hotelling (kW)[c]	1,900	1,900	3,000	3,000	3,000	2,300	2,300
Total load (kW)	6,200	6,200	7,300	7,300	7,300	6,600	6,600
Stack exit temperatures (^oF):[d]	316	316	762	762	590	520	520
Stack exit flowrates (acfm):[d]	22,000	23,000	54,000	47,000	73,400	99,000	87,000

[a]See Appendix B, Section B.6.1.

[b]SO_2 emission factor is based on fuel sulfur content (see Parameters worksheet)

[c]From Broadwater, Resource Report No. 9, Table 13, January 2006.

[d]See Appendix B, Section B.6.2.

EMISSIONS ASSOCIATED WITH UNLOADING (4300 kW)

								Worst case	
Short-term emiss. (g/s)	ST/RO	ST/gas	MSD/DO	MSD/gas	SSD/RO	GT/DO	GT/gas	oil	gas
NO_x	2.0	1.3	12.7	2.4	17.6	3.5	2.2	17.6	2.4
VOC	0.36	0.04	1.79	0.97	0.48	0.60	0.01	1.79	0.97
CO	0.14	0.6	2.1	5.6	1.9	0.2	0.6	2.1	5.6
SO_2	12.0	0.0	8.0	0.0	7.8	11.4	0.0	12.0	0.0
PM	2.9	0.05	1.1	1.1	1.0	0.6	0.05	2.9	1.1
Ammonia	0	0	0	0	0	0	0	0	0
HAP (total)	1.2E-02	1.3E-02	3.1E-02	3.1E-02	3.0E-02	1.2E-02	7.1E-03	3.1E-02	3.1E-02
Formaldehyde	2.1E-03	5.2E-04	4.9E-04	4.9E-04	4.8E-04	2.5E-03	4.9E-03	2.5E-03	4.9E-03

								Worst case	
Short-term emiss. (lb/hr)	ST/RO	ST/gas	MSD/DO	MSD/gas	SSD/RO	GT/DO	GT/gas	oil	gas
NO_x	16.1	10.4	100.5	19.0	139.4	27.5	17.6	139.4	19.0
VOC	2.8	0.3	14.2	7.7	3.8	4.7	0.12	14.22	7.67
CO	1.14	4.6	16.6	44.5	15.1	1.4	4.5	16.6	44.5
SO_2	95.6	0.03	63.4	0.02	61.7	90.7	0.03	95.6	0.0
PM	22.8	0.42	8.5	8.5	7.6	4.7	0.36	22.75	8.53
Ammonia	0	0	0	0	0	0	0	0	0
HAP (total)	0.096	0.10	0.24	0.24	0.24	0.092	0.056	2.4E-01	2.4E-01
Formaldehyde	0.016	0.004	0.004	0.004	0.004	0.020	0.039	2.0E-02	3.9E-02

SUMMARY OF MEETING
BETWEEN SAFE HARBOR ENERGY
AND U.S. ENVIRONMENTAL PROTECTION AGAENCY
APRIL 4, 2006

On April 4, 2006, representatives of Safe Harbor Energy Project (Safe Harbor) held a pre-filing meeting with representatives of the U.S. Environmental Protection Agency (EPA), Region 2 to discuss air emissions issues.

Introduction by John Filippelli (NEPA Coordinator)-and head of EPA Project team

Sources of Project Air Emissions – Presentation by Fred Pope (ENSR)

Attendees	Organization
Steven Riva	EPA/APB
Fred Pope	ENSR
Glenn Almquist	ASIG
Sheila Jones	Akin Gump Strauss Hauer & Feld LLP
John Filippelli	EPA – Strategic Planning
Mike Moltan	EPA – Air Programs Mobile Source Team
Reema Loutan	EPA – Air Programs Mobile Source Team
Frank Jon	EPA – Air Programs
Ray Werner	EPA – Client Air Programs Branch
Joe Siegel	EPA – Office of Regional Counsel

1. Four natural gas fired engine/generators - 3 working, 1 backup. Only power source for the island. Each system will be rated at 8.4 MW. SCR will be provided on the engine.

2. Three process heaters each rated at 106 MMBtu per hr (smaller than they were). 9 ppm for NO_x. Will be used November-March but not in summer.

3. Two backup generators – diesel – used as backup for island. 1.5 MW each. No. 2 0.2% sulfur oil. Client evaluating biodiesel.

4. Diesel fired-pump engines – emergency use – will run engines for approximately 0.5 to 1hr per week. For the PTE calculation, ASIG is assuming no need to include emissions that arise from emergency situations.

5. Emergency vent – will be used only when boil-off gas (methane) needs to be vented during abnormal situation, i.e., when normal operations are not

possible. The expectation is that the emergency vent will be used infrequently if at all.

Steve Riva – questioned the advisability of venting methane because, although not a regulated VOC, it is a greenhouse gas. Wants to know the expected frequency of use and expected volume released. Will the methane be above the ignition temperature when released? Riva expressed the view that the emergency vent has to be located away from sources of ignition.

6. LNG tankers. Size will vary. Most use Bunker C oil (heavy oil). Sulfur content varies.

Ray Werner: Do the ships use propulsion engines to pump the LNG when the ships are docking or other engines/power source?

Fred Pope/Glenn Almquist: The facility might be visited by either type of ship – those with separate engines/power sources and those that don't have separate power sources. There are approximately 180 ships in use today.

Ray Werner: Have you thought about cold-ironing?

Fred Pope: In order for ships to "cold-iron" they have to be designed to take power from the facility – if they are not so designed "requiring" cold ironing does not work. ASIG cannot "require" cold - ironing because there is no dedicated fleet for the facility. Also, based on the information we have obtained, most ships are not designed to allow them to cold-iron.

There was further discussion on cold-ironing that focused on whether cold-ironing of LNG tankers would be permissible under USCG rules and policies.

Sheila Jones: We will find out if there are safety concerns and thus prohibitions on cold-ironing of LNG tankers.

7. Mobile Sources

a) Supply ships

b) Motor vehicles on the island

c) Tugs - one standby for fire fighting

<u>Thresholds for Regulatory Applicability</u>

- Confirm that the LNG terminal is not a fuel conversion plant – EPA agrees.

- Discussed the process heaters. ASIG does not believe the process heaters are “boilers” for purposes of the PSD regulations.

- Steve Riva: “Boilers” are a listed category. If process heaters are boilers, then the PSD source threshold is 100 tpy. Are any of the other sources of air emissions on the island “supporting sources” to the process heaters? Under the PSD regulations, the emissions from such sources should be added to projected emissions from the process heaters in order to determine if the 100 tpy standard is triggered.

- Steve Riva: LAER for the process heaters will be SCR.

- To summarize, EPA’s view is the process heater is a “boiler.” ASIG does not agree but in an effort to achieve a consensus agreed to look at the definitions of “boiler” in the air regulations and to review the operations of the process heaters in light of those definitions. ASIG also agreed to review the facility process in order to determine which of the other emission sources, if any, “support” the process heaters.

<u>NNSR – Threshold</u>

Steve Riva: The State is not planning to change the thresholds for NO_x and VOC (currently the threshold is 25 tpy) even though the ozone standard is changing (8 hr. vs. 1 hr. ozone standard issue).

All parties agreed the non-attainment pollutants are: PM-2.5 and ozone (NO_x , VOC).

Source Impact Analysis modeling– Steve Riva stated that Fred Pope should address his questions to Anna Marie (EPA’s modeler) first and if other people need to be involved calls will be set up.

PTE – EPA’s view is that ASIG should include LNG tanker unloading emissions and only emissions from sources 1,2, 3 and 4 (described at the beginning of the meeting) in the source impact analysis. Tugs and supply boats not part of the PSD analysis and the air quality impact analysis.

Increments: EPA’s view is that “stationary source” and LNG tanker unloading emissions must be modeled to determine the facility increment consumption.

Discussed NY State law relating air pollution that is not part of the SIP. The question: Is it “applicable” law under the Deepwater Port Act? Limited discussion of this issue – no resolution. Sheila Jones and Joseph Siegel to discuss further.

<u>Conformity</u>

- Discussed ozone precursor threshold for Conformity.

- General Conformity analysis – update still not done, so the PM-2.5 threshold will be the same as the threshold for PM-10.

- State has not yet specified any PM 2.5 sources as “significant.”

- Discussed the potential to trigger the conformity analysis obligation by virtue of construction activities. EPA’s view - sequence the construction activity over the period of construction. If you trigger conformity in year 2 then you can explore sequencing the activities and thereby avoid triggering the obligation to conduct a conformity analysis. If you nonetheless exceed the trigger, then you will have to mitigate to zero – you can use offsets to mitigate but you must have offsets available in the year that you exceed the conformity trigger.

- Modeling not required for conformity.

- What constitutes an indirect emission? – look to the regs for definition.

B.7. LNG Unloading (Vessel Emissions)

The "LNG Unloading from Vessels" worksheet identifies short-term emissions and exhaust gas characteristics from the various LNG vessel types. As shown in Appendix A5 and discussed in Section 3.2 of this application, there are four different LNG tanker types considered, three of which are capable of firing either oil or gas to generate electricity.

All vessels will be unloading at a rate of 14,000 m^3 LNG/hr, which is estimated to require approximately 4,300 kW of electrical power.

B.7.1 Fuel Consumption and Emissions

Entec (2002)[2] developed fuel consumption factors and emission factors (all expressed in g/kWh) for oil-fired marine vessels, and these data were also used by Starcrest (2003) to develop a marine vessel emissions inventory for the New York/Northern New Jersey/Long Island nonattainment area.[9] Entec's report included separate factors for main engines (underway), main engines (in port/maneuvering), and auxiliary engines; factors for main engines (in port/maneuvering) from Table 2.9 of that report were used for the ST/RO, MSD/DO, and GT/DO cases. For the SSD/RO case, the main engines are mechanical-drive engines, and therefore factors for auxiliary engines were used (Table 2.10 of the Entec report). Because the Entec report did not include CO emissions, CO emission factors from the Starcrest report (Table D.9) were used. Emission factors for total HAP and formaldehyde were calculated based on fuel consumption per kWh and emission factors from EPA's AP-42 publication, as shown in the worksheets labeled "HAP Emission Factor Calculation Sheet – Residual Oil Combustion (External)", "HAP Emission Factor Calculation Sheet – Oil-Fired Turbines", and the previously mentioned "HAP Emission Factor Calculation Sheet – Large Stationary Diesel Engines".

For the cases in which the ST, MSD, and GT technologies fire gas instead of oil, fuel consumption (g/kWh) was estimated on an equivalent heat-content basis: for example, in the case of the ST, Entec estimated fuel consumption of 336 g/kWh for the oil-fired case. The fuel consumption for the gas-fired case was estimated based on the relative heat contents of the oil (17,608 Btu/lb) and gas (23,544 Btu/lb): i.e.,

$$\text{Fuel consumption} = (336\ \text{g/kWh})(17{,}608\ \text{Btu/lb})/(23{,}544\ \text{Btu/lb}) = 251\ \text{g/kWh}. \qquad \text{(B-7)}$$

For the GT/gas case, a NO_x emissions factor of 2 g/kWh was used, based on data for Wärtsilä 50 DF (see Appendix A6). For the other gas-fired cases, emission factors in g/kWh were calculated based on emission factors from EPA's AP-42 publication and the calculated fuel consumption per kWh.

Emissions of total HAP and formaldehyde were calculated based on data from EPA's AP-42 publication (as shown in the worksheet labeled "HAP Emission Factor Calculation Sheet – Natural Gas-Fired Turbines" and the previously referenced worksheet labeled "HAP Emission Factor Calculation Sheet – Natural Gas Combustion (External)". For the MSD/gas case, AP-42 does not provide HAP emission factors, and HAP emissions were conservatively assumed to be the same as for the MSD/oil case.

For all technology/fuel combinations, SO_2 emissions were conservatively calculated based on 100% conversion of the maximum sulfur content to SO_2.

B.7.2 Exhaust Gas Parameters

Exhaust gas parameters were calculated based on the total loads that the fuel-burning sources would actually be operating at; i.e., loads associated with both unloading and hotelling. Estimates of hotelling

[9] Starcrest Consulting Group (2003), "The New York, Northern New Jersey, Long Island Nonattainment Area Commercial Marine Vessel Emissions Inventory," April.

USCG Comment #10*:

Air Quality Analysis: With respect to the Air Quality Analysis portion of the Application, we have the following comments:

1. **The air quality modeling input and output files from AERMOD and OCD were not submitted as part of the permit application. Therefore we are unable to confirm any of the modeling input, results and conclusions. Please submit a copy of the air quality analysis on a diskette or other appropriate electronic storage device, with clearly named input and output files including the meteorological data. Please retain the model's filename extension.**

Response:

Input and output files from AERMOD and OCD as well as the processed meteorological data will be provided on disk to EPA.

2. **The application did not address the comments EPA made previously including those provided in the letter dated April 19, 2007 to William VanHerwarde. Please include a response to these comments as well as other earlier comments in future applications. Of particular note is the comment regarding the sensitivity analysis of the model's mixing height. The application alludes to such a sensitivity analysis but the documentation and results were not provided. In addition, EPA's letters on the Project specified that the Fish & Wildlife Service's Federal Land Manger for Brigantine Bay and Marsh must be notified and consulted regarding impacts to endangered wildlife. To our knowledge, this notification and consultation has not happened to date. If the FLM has been notified, please provide evidence of the notification and copies of all correspondence related to this topic.**

Response:

The application addressed most of comments provided by EPA in the April 19, 2007 letter to ASIG (Steve Riva, 4/19/07 letter to William Vanderwarde Re: Addendum to the Air Quality Evaluation and Modeling Protocol for the Safe Harbor Energy LNG Offshore Facility). A mixing height sensitivity analysis was conducted and described in Volume 2, Exhibit X, Section 6.3.2 of the air permit application, including the modeling of several fixed mixing heights (40, 150, 250, 350, and 500 meters). In addition, overland meteorological data were used in the OCD model to evaluate shoreline locations (also described in Section 6.3.2 of the air application). Regarding the Brigantine National Wildlife Refuge in New Jersey, as requested, the air permit application will be submitted to the US Fish and Wildlife Service's Federal Land Manager

4. **A PSD increment analysis was not addressed for any pollutant. Thus far, an examination of the air impacts of the facility alone indicates that the 24-hour SO2 PSD increment is already exceeded. This exceedance must be addressed in order to receive an air permit. Note, according to federal regulations major and minor sources consume increment. NYSDEC also requires the assessment of the increment from minor sources. Therefore, please address increment whether the Project will be a major or minor source.**

Response:

ASIG has requested a meeting with EPA to discuss this comment. After consultation with EPA, a response will be provided.

5. The NAAQS analysis was not complete. It did not include the cumulative impacts from other nearby sources such as the mobile sources on the Safe Harbor Energy Island or the on-shore sources that could impact the significant impact area.

Response:

Background sources have been accounted for by adding a conservative ambient measured concentration to maximum model-predicted impact concentrations to demonstrate compliance. As indicated in EPA's April 19, 2007 letter to ASIG (Steve Riva, 4/19/07 letter to William Vanderwarde Re: Addendum to the Air Quality Evaluation and Modeling Protocol for the Safe Harbor Energy LNG Offshore Facility), this procedure is acceptable to EPA provided it is demonstrated that measured background is indeed conservative and representative of the type of emission from sources within Safe Harbor Energy's Significant Impact Area. The conservativeness and representativeness of selected background concentration data are described in the response to USCG Comment #18.

6. An Environmental Justice analysis, examining all aspects of the proposed project, should be part of the application. For guidance, we recommend visiting EPA's website which contains EPA Region 2's Interim Policy on Environmental Justice. Please submit an analysis consistent with the EPA guidance.

Response:

A complete environmental justice analysis, pursuant to the requirements defined in Executive Order 12898, entitled Federal Actions to Address Environmental Justice in Minority Populations, and EPA Region 2's Interim Environmental Justice Policy has been included in Volume Three, Part One – Topic Report Five, Section 5.3.6. As stated in Section 5.3.6 none of the proposed facilities, staging areas, or shore base will be located in areas where the minority populations exceed either the national or EPA Region 2 thresholds. Kings County, New York, one of the potential locations under consideration for the proposed staging area, is the only county in which the low-income population (23.8 percent) exceeds the national threshold of 22.7; but falls below the EPA Region 2 threshold of 24.8 percent. However, as further stated in Section 5.3.6, while construction and operation of the Project could result in minor increases in noise and or/air emissions, these impacts will be short-term and localized. In addition, activities at the selected staging areas or shore base would be consistent with the sites existing use. As such, construction and operation activities would not likely result in increased impacts to minority and low-income populations in Kings County or any other proposed staging area and/or shore base locations.

8. A Net Air Quality Benefit Analysis must be included as part of the nonattainment application. Please see NYSDEC's 6NYCRR Part 231 regulation for further details on this requirement.

Response:

ASIG has requested a meeting with EPA to discuss this comment. After consultation with EPA, a response will be provided.

9. The April 5, 2005 memorandum from Steve Page, Director of OAQPS does not state that if the PM10 NAAQS are met, that the PM2.5 NAAQS are met. This memorandum refers to the nonattainment requirements regarding applicability thresholds and offsets. Please clarify this language in the application as stated in Exhibit X, Page X-31.

Response:

ASIG has requested a meeting with EPA to discuss this comment. After consultation with EPA, a response will be provided.

10. The impacts from startups and shutdowns must be assessed to be in compliance with the applicable ambient air quality standards (e.g., USEPA, NYSDEC, or NJDEP, where applicable). Please submit an analysis that includes emissions and impacts from start up and shutdown.

Response:

ASIG has requested a meeting with EPA to discuss this comment. After consultation with EPA, a response will be provided.

11. The load analysis which leads to the worse case air quality impacts must be part of the air quality impact analysis in the application.

Response:

Volume Two, Exhibit X, Section 6.2 of the Air Permit Application (included as Attachment 10.11-1) describes the emission parameters and operating scenarios evaluated with air quality dispersion modeling. To ensure that maximum potential combined impact concentrations were determined for the various Project emission sources under various load conditions, several conservative assumptions were made for the modeling analysis. To ensure an evaluation of worst-case conditions, for some sources it was conservatively assumed that the maximum emissions case was combined with the worst-case stack exhaust flow conditions (i.e. minimum flow and temperature conditions).

*The USCG comments did not reference 10.3 and 10.7, therefore our response only includes 10.1, 10.2, 10.4-10.6, and 10.8-10.11.

Attachment 10.11-1

- Volume Two, Exhibit X, Section 6.2

6.2 EMISSION SOURCE PARAMETERS AND OPERATING SCENARIOS

Pollutant emission rates for all Project emissions sources are provided in Tables 3-1 through 3-6. Detailed emission calculations and source data are provided in Appendix B. Source location and stack parameters for the Safe Harbor Energy emission sources are provided in Table 6-1. To ensure that maximum potential combined impact concentrations were determined for the various Project emission sources and possible load conditions, several conservative assumptions were made for the modeling analysis. The load condition for the LNG tanker emission sources is governed by the LNG unloading rate of 14,000 m^3/hr and the corresponding demand of 4,300 kW for the unloading pumps. These rates correspond to different emissions and stack exhaust characteristics for the various types of tanker vessels that may serve the Project (see emission calculation spreadsheet in Appendix B for LNG unloading from vessels). To ensure an evaluation of worst-case conditions, it was conservatively assumed that the maximum emissions case for each pollutant (by vessel and fuel type) was combined with the worst-case stack exhaust flow conditions (minimum flow and temperature conditions). The modeling also conservatively assumes all potential LNG tanker emissions will be emitted from the stack of a single vessel, while these emissions will actually be emitted from one of two stack positions (dock locations) over the course of a year.

The Wartsila gas engine generators will typically operate between 100 percent and 75 percent load. Maximum operating load will typically be served by three units operating at 100 percent load, but because four units operating at 75 percent load could also satisfy this load, the four-unit, 75 percent load case condition was evaluated for modeling to provide the worst case for exhaust flow conditions combined with emissions. The three gas heater units will also operate between 100 percent and 75 percent load. Total load will never exceed 246 MMBtu/hr combined, which corresponds to one unit operating at 100 percent load with two units operating at 75 percent load. However, to ensure maximum impacts are predicted for these units, the emissions at 100 percent load were modeled with the worst-case exhaust flows conditions for 75 percent load for the three units. Both the emergency diesel generator and the fire pump engines were modeled in a similar way, with emissions corresponding to 100 percent load conservatively modeled with part load exhaust flow conditions.

These conservative assumptions were made to reduce the number of load conditions that would need to be evaluated in the modeling analysis.

USCG Comment #11:

Volume 3, Part 2, Appendix C, Modeling Protocol: Please verify that the surface characteristic to be used for the AERMET analyses include seasonal components of water and ice conditions.

Response:

This is confirmed. The surface characteristics used in the AERMET dispersion modeling were the seasonal frequency values for water as recommended in the AERMOD User's Guide**.**

USCG Comment #12:

Volume 3, Part 2, Appendix C, Modeling Protocol: Please address why the first six sources are included in Tables 2-5b and 2-5c? The emissions from these sources are included in the emission totals being compared to the general conformity thresholds, but should be excluded from the general conformity applicability analysis because they are already included in the facility's PTE (Table 2-5a).

Response:

It is correct that the first six sources listed on Tables 2-5b and 2-5c of the modeling protocol should not be included in the project-related emissions totals compared to general conformity thresholds. They were not included in project-related emissions compared to conformity thresholds in the general conformity technical support document (Volume Five, Part One – Attachment 2-1 General Conformity). Tables 2-5b and 2-5c of the modeling protocol were intended to list sources to be modeled in the NEPA-related dispersion modeling analyses and Table 2-5b was introduced as such on page 2-5 of the modeling protocol text (Table 2-5c was not referenced in the text). However, the listing of the conformity applicability thresholds on these tables made them confusing.

USCG Comment #13:

Volume Three, Part One, Topic Report Eight. We have not found Greenhouse Gas (GHG) emission estimates for the Project (Construction, Operations and Decommission phases) in the Application materials submitted to date. Please provide GHG emissions estimates (or identify where we can find them) for Project emissions. If the impacts of GHG emitted by the Project have been evaluated (including cumulative impacts), please provide descriptions of the analyses and results.

Response:

Greenhouse Gas (GHG) emissions will consist primarily of carbon dioxide (CO_2) emissions with a lesser quantity of methane (CH_4) emissions from combustion sources. Yearly GHG emissions from all of the project sources listed in Volume Three, Part One – Topic Report Eight, Table 8-5 have been estimated to total 150,642 tons of CO_2 and 781 tons of CH_4. This is equivalent to 151,521 metric tons of CO_2 - equivalent GHG emissions annually from the Project.

GHG emissions have not been quantified by or for the other actions considered for cumulative assessment listed in Table 1 of Volume Five, Part One, Attachment 7-1. However, for reference, commercial shipping emissions in the New York region have been estimated in two studies at 6.2 million metric tons per year and 8.75 million metric tons per year of CO_2 equivalent GHG emissions (Mayor's Office of Operations 2007; ICF Consulting 2005). Project GHG emissions would therefore be less than 2.5 percent and 1.8 percent of these commercial shipping totals, respectively.

Reference:

Mayor's Office of Operations, Office of Long-Term Planning and Sustainability. "Inventory of New York City Greenhouse Gas Emissions," April 2007. Available online at http://www.nyc.gov/html/om/pdf/ccp_report041007.pdf .

ICF Consulting. "Estimating Transportation-Related Greenhouse Gas Emissions and Energy Use in New York State." March 18, 2005. Available online at http://climate.dot.gov/publications/estimating_greenhouse_ny/pdf/entire.pdf.

USCG Comment #14:

Volume Three, Part One, Topic Report Eight. The application should address the fuel mix used in LNG tanker ships from the time the vessels enter the Exclusive Economic Zone (EEZ) of the U.S. Please include discussion of how LNG ships serving the terminal will comply with recent changes to MARPOL Annex VI regulations and proposed GHG reduction initiatives endorsed by the Marine Environment Protection Committee (MEPC) of International Maritime Organization (IMO).

Response:

The application addressed the fuel mix used in LNG tanker ships from the time that they enter the Safety Zone. There are numerous LNG vessels being operated by many different entities within the U.S. Exclusive Economic Zone (EEZ). ASIG cannot readily obtain information about the fuel mix being used by those vessels. The best that it can do is record any relevant legal requirements and report any trends in the shipping industry.

ASIG has no control or jurisdiction over the vessels from the time that they enter the EEZ to the time that they are picked up by tugs just outside the Safety Zone; ASIG cannot provide information regarding how the various operators plan to comply with the recent changes in the MARPOL Annex VI regulations (or whether they would comply with proposed GHG reduction initiatives before they are finalized/ratified). However, in association with cooperating LNG operators, ASIG will develop a procedure for tracking and maintaining records with respect to which fuels are fired by the vessels within the Safety Zone.

USCG Comment #15:

Volume Three, Part One, Topic Report Eight. Discuss the regulatory implications to the Project of the revised 8-hour ozone standard.

Response:

The area was designated as an ozone nonattainment area and is expected to remain an ozone nonattainment area under the revised 8-hour ozone standard. Thus, there are no regulatory implications associated with the revised standard. As stated on page 8-10 of Volume Three, Part One – Topic Report Eight (see Attachment 15-1), "New York has proposed an update to 6 NYCRR 231 to incorporate the 8-hour standard designations, and the major source thresholds for the New York-Long Island-Northern New Jersey area remain unchanged. As shown in Section 8.3.1 of Volume Three, Part One – Topic Report Eight, total emissions from Safe Harbor Energy's Island-based sources will exceed 25 tpy VOC and 25 tpy NO_x. Therefore, the air permit application (included as Volume Two, Exhibit X-Preconstruction Air Permit Application) was drafted assuming that NNSR applies to the Project."

Attachment 15-1

- Volume Three, Part One – Topic Report Eight, page 8-10

area, a "major source" is one with the potential to emit 25 tpy or more of VOC or NO_x, whereas in the remainder of the state "major" sources are those with the potential to emit 50 tpy or more of VOC, or 100 tpy or more of NO_x [6 NYCRR 231-2.12]. Although these major source thresholds were based on the 1-hour ozone NAAQS (which was revoked for all areas in New York effective June 15, 2005), New York has proposed an update to 6 NYCRR 231 to incorporate the 8-hour standard designations, and the major source thresholds for the New York-Long Island-Northern New Jersey area remain unchanged. As shown in Section 8.3.1, total emissions from Safe Harbor Energy's Island-based sources will exceed 25 tpy VOC and 25 tpy NO_x. Therefore, the air permit application (included as Volume Two, Exhibit X – Preconstruction Air Permit Application) was drafted assuming that NNSR applies to the Project.

The permit application requirements identified in 6 NYCRR 231-2.4(a) (2) are as follows and Project compliance with these requirements is addressed in the preconstruction permit application contained in Volume Two, Exhibit X – Preconstruction Air Permit Application:

(1) Certify that all emission units which are part of any major facility located in New York State and under the applicant's ownership or control (or under the ownership or control of any entity which controls, is controlled by, or has common control with the applicant) are in compliance, or are on a schedule for compliance, with all applicable New York air pollution emission limitations and standards.

(2) Submit an analysis of alternative sites, sizes, production processes, and environmental control techniques which demonstrates that benefits of the proposed facility significantly outweigh the environmental and social costs imposed as a result of its location or construction within New York State (although, as stated previously, this Project is not being located within New York State).

(3) Submit a LAER analysis.

(4) Prior to permit issuance, the Project will also be required to submit a list of offset sources, submit a "Use of Emission Reduction Credits Form," submit a copy of each modified permit establishing ERCs for any future reductions and comply with contribution demonstration requirements [6 NYCRR 231-2.4(b)]. (These submittals will be made to EPA Region 2 at a later date.)

For $PM_{2.5}$, EPA issued an NSR implementation policy in April 2005, noting that "the absence of a final PM-2.5 implementation rule makes administering a PM-2.5 nonattainment major NSR program infeasible. Accordingly, until we promulgate the PM-2.5 major NSR regulations, States should use a PM-10 nonattainment major NSR program as a surrogate to address the requirements of nonattainment major NSR for the PM-2.5 NAAQS."[2] Specifically, sources are assumed to be major for $PM_{2.5}$ if they have potential PM_{10} emissions of 100 tpy. (Although EPA issued a final $PM_{2.5}$ implementation rule on April 25, 2007, they have not yet promulgated $PM_{2.5}$ major NSR regulations.) As shown in Section 8.3.1, total combined PM emissions from Safe Harbor Energy's Island-based sources and vessel unloading will not exceed 100 tpy; therefore, NNSR regulations do not apply to Safe Harbor Energy with respect to $PM_{2.5}$.

EPA's PSD regulations apply to "major" stationary sources located in attainment (or unclassifiable) areas, where "major" stationary sources are those with the potential to emit 250 tpy or more of any pollutant, or—in the case of fossil fuel-fired steam electric plants with heat input rates of 250 MMBtu/hr or more, or combinations of fossil fuel-fired boilers with a combined heat input rate of 250 MMBtu/hr or more—the potential to emit 100 tpy or more of any pollutant. New York's proposed revisions to Part 231 regulations identify these same major source thresholds. The combined heat input rate of the process heaters is less than 250 MMBtu/hr. Furthermore, as shown in Section 8.3.1, potential emissions from all Island-based sources and vessel unloading are below 100 tpy for all pollutants. Therefore, the Project is not subject to PSD regulations.

[2] Stephen Page (EPA), "Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas," memorandum, April 5, 2005.

area, a "major source" is one with the potential to emit 25 tpy or more of VOC or NO_x, whereas in the remainder of the state "major" sources are those with the potential to emit 50 tpy or more of VOC, or 100 tpy or more of NO_x [6 NYCRR 231-2.12]. Although these major source thresholds were based on the 1-hour ozone NAAQS (which was revoked for all areas in New York effective June 15, 2005), New York has proposed an update to 6 NYCRR 231 to incorporate the 8-hour standard designations, and the major source thresholds for the New York-Long Island-Northern New Jersey area remain unchanged. As shown in Section 8.3.1, total emissions from Safe Harbor Energy's Island-based sources will exceed 25 tpy VOC and 25 tpy NO_x. Therefore, the air permit application (included as Volume Two, Exhibit X – Preconstruction Air Permit Application) was drafted assuming that NNSR applies to the Project.

The permit application requirements identified in 6 NYCRR 231-2.4(a) (2) are as follows and Project compliance with these requirements is addressed in the preconstruction permit application contained in Volume Two, Exhibit X – Preconstruction Air Permit Application:

(1) Certify that all emission units which are part of any major facility located in New York State and under the applicant's ownership or control (or under the ownership or control of any entity which controls, is controlled by, or has common control with the applicant) are in compliance, or are on a schedule for compliance, with all applicable New York air pollution emission limitations and standards.

(2) Submit an analysis of alternative sites, sizes, production processes, and environmental control techniques which demonstrates that benefits of the proposed facility significantly outweigh the environmental and social costs imposed as a result of its location or construction within New York State (although, as stated previously, this Project is not being located within New York State).

(3) Submit a LAER analysis.

(4) Prior to permit issuance, the Project will also be required to submit a list of offset sources, submit a "Use of Emission Reduction Credits Form," submit a copy of each modified permit establishing ERCs for any future reductions and comply with contribution demonstration requirements [6 NYCRR 231-2.4(b)]. (These submittals will be made to EPA Region 2 at a later date.)

For $PM_{2.5}$, EPA issued an NSR implementation policy in April 2005, noting that "the absence of a final PM-2.5 implementation rule makes administering a PM-2.5 nonattainment major NSR program infeasible. Accordingly, until we promulgate the PM-2.5 major NSR regulations, States should use a PM-10 nonattainment major NSR program as a surrogate to address the requirements of nonattainment major NSR for the PM-2.5 NAAQS."[2] Specifically, sources are assumed to be major for $PM_{2.5}$ if they have potential PM_{10} emissions of 100 tpy. (Although EPA issued a final $PM_{2.5}$ implementation rule on April 25, 2007, they have not yet promulgated $PM_{2.5}$ major NSR regulations.) As shown in Section 8.3.1, total combined PM emissions from Safe Harbor Energy's Island-based sources and vessel unloading will not exceed 100 tpy; therefore, NNSR regulations do not apply to Safe Harbor Energy with respect to $PM_{2.5}$.

EPA's PSD regulations apply to "major" stationary sources located in attainment (or unclassifiable) areas, where "major" stationary sources are those with the potential to emit 250 tpy or more of any pollutant, or—in the case of fossil fuel-fired steam electric plants with heat input rates of 250 MMBtu/hr or more, or combinations of fossil fuel-fired boilers with a combined heat input rate of 250 MMBtu/hr or more—the potential to emit 100 tpy or more of any pollutant. New York's proposed revisions to Part 231 regulations identify these same major source thresholds. The combined heat input rate of the process heaters is less than 250 MMBtu/hr. Furthermore, as shown in Section 8.3.1, potential emissions from all Island-based sources and vessel unloading are below 100 tpy for all pollutants. Therefore, the Project is not subject to PSD regulations.

[2] Stephen Page (EPA), "Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas," memorandum, April 5, 2005.

USCG Comment #16:

Volume Three, Part One, Topic Report Eight. Update applicable tables summarizing NAAQS to reflect the revised NAAQS for PM2.5 and ozone.

Response:

The current NAAQS for $PM_{2.5}$ and ozone were provided in Table 8-4 of Volume Three, Part One – Topic Report Eight, Table 8-4 and are provided as Attachment 16-1 for convenience.

Attachment 16-1

- Volume Three, Part One – Topic Report Eight, Table 8-4

Table 8-4 National and New York Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS[1] Primary ($\mu g/m^3$)	NAAQS[1] Secondary ($\mu g/m^3$)	NYAAQS[2] ($\mu g/m^3$)
O_3	8-hour[3]	157	157	157
NO_2	Annual[4]	100	100	100
CO	8-hour[5]	10,000	None	10,000
	1-hour[5]	40,000	None	40,000
SO_2	Annual[4]	80	None	80
	24-hour[5]	365	None	365
	3-hour[5]	None	1,300	1,300
PM_{10}	24-hour[5]	150	150	250
$PM_{2.5}$	Annual[6]	15	15	15[7]
	24-hour[8]	35	35	65[7,9]
Pb	3-month[4]	1.5	1.5	None[9]

(1) National Ambient Air Quality Standards, as defined in 40 CFR 50.

(2) New York Ambient Air Quality Standards, as defined in 6 NYCRR 257. New York's regulations also include pollutants other than those listed here (settleable particulates, nonmethane hydrocarbons, fluorides, beryllium, and hydrogen sulfide) but these standards do not influence regulatory applicability.

(3) NAAQS is rolling average; standard is met when the 3-year average of fourth-highest daily maximum 8-hour average ozone concentration is at or below this concentration. NYAAQS is a 1-hour average standard for photochemical oxidants (including O_3, peroxyacyl nitrates (PAN), organic peroxides, and other oxidants measured by the potassium iodide method).

(4) Not to be exceeded.

(5) Not to be exceeded more than once per year. (For the PM_{10} NAAQS, this standard is determined as per 40 CFR 60, Appendix K.)

(6) To attain this standard, the 3-year average of the weighted annual mean $PM_{2.5}$ concentrations from single or multiple community-oriented monitors must not exceed 15.0 $\mu g/m^3$.

(7) Per NYSDEC policy CP-33 on $PM_{2.5}$ (December 2003).

(8) To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at population-oriented monitors must not exceed the value shown.

(9) The latest federal standards have not yet incorporated into 6 NYCRR 257.

USCG Comment #17:

Volume Three, Part One, Topic Report Eight. Although hazardous air pollutant emissions have been quantified for some sources, we could not find documentation of compliance with NYSDEC Policy DAR-1: Guidelines for the Control of Toxic Ambient Air Contaminants, including an air quality impact analysis. ASIG should address this issue, report consultations with appropriate state agencies and update emission and ambient impact tables as necessary.

Response:

ASIG has requested a meeting with EPA to discuss this comment. After consultation with EPA, a response will be provided.

USCG Comment #18:

Volume Three, Part One, Topic Report Eight. Table 8-3. More recent ambient air quality data are now available than 2002 to 2005. The most recent three years of data should be identified and summarized, and more detailed information should be provided for the monitoring locations. Also, for purposes of establishing ambient background concentrations representative of the proposed Safe Harbor Energy offshore location and for use in the air quality impact analyses, provide the rationale for using data from the selected monitoring stations.

Response:

Table 8-3 has been revised for the most recent four years of available monitoring data (2004 – 2007) and it is attached as Attachment 18-1. In addition, the monitoring stations selected to determine these background concentrations have been revised. New stations were selected since the original stations (Eisenhower Park and Elizabeth Lab) have discontinued monitoring some pollutants (PM_{10} and CO) for the most recent period, and because it was determined that other monitoring stations are more representative of the project location. The new monitoring stations, and the rationale for their selection, are described below.

The selection of monitoring stations was based on their location relative to the Project site and the prevailing wind directions. As shown on Figure 6-1 on page X-52 of the air permit application, the prevailing wind directions in the Project site area are generally from the south-southwesterly, southwesterly, and westerly sectors. Therefore, these directions (winds from New Jersey towards the Project site) were reviewed to determine representative stations. Other factors considered include proximity to Project site, and proximity to the shore. Stations closest to the Project site and shore in the prevailing wind directions were selected. The monitoring stations used to determine background concentrations are as follows:

- Perth Amboy (site #34022203) – for SO2 and CO;
- Rutgers Univ. (site # 340230011) – for NO2;
- Toms River (site #340230011) – for PM2.5;
- Atlantic City (site #340011006) – for PM10

In addition to being spatially representative as discussed above, these monitoring sites are located in areas that are largely developed and would be influenced by the emissions of both mobile sources (e.g., trucks, cars, ferries, and ship traffic), and stationary sources (e.g. power generating facilities and other industrial plants, and residential sources). The urban plume (air mass) that would most typically traverse the Project site comes from the direction of the prevailing winds. The Project site is expected to have few proximate sources contributing to pollution over a significant duration (i.e., 24 hours) since virtually all commercial and recreational vessels are in transit. The island is outside the commercial shipping lanes. Therefore, pollution advection from the onshore sources is considered the primary component to background concentrations, and therefore use of monitoring data from these land-based stations as background is conservative.

The Project will use background concentrations based on the second-highest 1-hour concentrations, second-highest 3-hour concentrations, second-highest 8-hour concentrations, second-highest 24-hour concentrations (except for $PM_{2.5}$) and annual average concentrations (except for $PM_{2.5}$) over the 4 year period of 2004 through 2007. Background concentrations for 24-hour $PM_{2.5}$ will be based on the 3 year average of the 98th percentile values and annual $PM_{2.5}$ will be based on the 3 year average of annual average values. These assumptions for background concentration values are consistent with the NAAQS for these pollutants.

Attachment 18-1

- Volume Three, Part One, Topic Report Eight, Table 8-3 (revised)

Table 8-3 Summary of Ambient Air Quality Data Measured Near the Project (revised)

Pollutant	Averaging Period	Standard ($\mu g/m^3$)	Year	Concentration ($\mu g/m^3$)
SO_2	3-hour (2nd high)	1,300	2004	77.2
			2005	**106.5**
			2006	58.6
			2007	45.3
	24-hour (2nd high)	365	2004	47.9
			2005	**55.9**
			2006	37.3
			2007	24.0
	Annual	80	2004	10.6
			2005	**10.6**
			2006	8.0
			2007	8.0
NO_2	Annual	100	2004	32.5
			2005	**34.4**
			2006	26.8
			2007	26.8
$PM_{2.5}$	24-hour (98th %)	35	2004	30.9
			2005	32.2
			2006	29.3
			3 year average	**30.8**
			2007	28.5
			3 year average	30.0
	Annual	15	2004	10.4
			2005	11.8
			2006	10.2
			3 year average	**10.8**
			2007	10.2
			3 year average	10.7
PM_{10}	24-hour (2nd high)	150	2004	32
			2005	**50**
			2006	35
			2007	42
	Annual	50	2004	19
			2005	**23**
			2006	20
			2007	21
CO	1-hour (2nd high)	40,000	2004	**4076.5**
			2005	3494.2
			2006	3377.7
			2007	2329.5
	8-hour (2nd high)	10,000	2004	**2562.4**
			2005	2213.0
			2006	1863.6
			2007	1747.1

Source: EPA Airs Data: 2004, 2005, 2006, and 2007 (derived from NJDEP monitoring data)

(1) Concentrations listed in the table are the second-highest 1-hour concentrations, second-highest 3-hour concentrations, second-highest 8-hour concentrations, second-highest 24-hour concentrations (except for $PM_{2.5}$) and annual average concentrations. 24-hour $PM_{2.5}$ concentrations are based on the 98th percentile values.

(2) Concentrations in bold represent the highest measured value to be used to represent background.

(3) SO_2, NO_2 and CO concentrations are reported by the NJDEP in parts per million (ppm). These concentrations were converted to $\mu g/m^3$ with the following formula: ppm x M / 0.02404 = $\mu g/m^3$, where M is the pollutant molecular weight

(4) Monitoring data compiled from the following monitoring NJDEP sites: Perth Amboy #34022203 (SO_2 and CO); Rutgers Univ. # 340230011 (NO_2); Toms River #340230011 ($PM_{2.5}$), Atlantic City #340011006 (PM_{10})

USCG Comment #19:

Volume Three, Part One, Topic Report Eight. Address the applicability of OSHA's Process Safety Management (PSM) regulations to the Project.

Response:

Response to this data request will be provided on or before January 31, 2009.

USCG Comment #20:

Volume Three, Part One, Topic Report Eight. Discuss the feasibility of cold-ironing the ships at berth. Include a discussion on air quality, safety, and the anticipated availability/fleet options that would be capable of cold-ironing. Identify how this would affect emergency situations and the number of standby tugs that would be required in addition to those required when not cold-ironing. Include a comparison of the emissions from the tanker if not cold-ironing (assuming non-US fuels) and the tugs required for standby (assuming US fuels) that would additionally be required beyond normal operation because of cold-ironing.

Response:

Response to this data request will be provided on or before January 31, 2009.

USCG Comment #21:

According to NYSDEC, the air permit application inaccurately states that the protocol used in the application modeling was submitted to NYSDEC, and suggests that DEC approved it. Please provide evidence that the protocol was submitted and approved or describe plans for its submittal.

Response:

The permit application does not state that the protocol used in the application modeling was submitted to NYSDEC. As EPA is the lead agency, the final protocol was submitted to EPA and not NYSDEC. Volume Two, Exhibit X, Section 6.3.2 and Appendix D of the application both refer to EPA comments on the protocol. However, NYSDEC did comment on an earlier version of the protocol—i.e., Leon Sedefian of NYSDEC identified comments in a May 9, 2006 letter to Fred Pope of ENSR and identified additional issues in a June 5, 2006 conference call with ASIG and its consultants. Pertinent correspondence included with the modeling protocol is provided in Attachment 21-1.

Attachment 21-1

- Volume Three, Part Two, Appendix C Air Quality Evaluation and Modeling Protocol, Note to Reader

- Volume Three, Part Two, Appendix C Air Quality Evaluation and Modeling Protocol, Appendix A-1 L. Sedefian of New York State Department of Environmental Conservation (NYSDEC) to F. Pope of ENSR Corporation dated May 9, 2006

- Volume Three, Part Two, Appendix C Air Quality Evaluation and Modeling Protocol, Appendix A-3 Summary of June 5, 2006 Conference Call with NYSDEC

Appendix C
Air Quality Evaluation and Modeling Protocol

May 2007

Prepared for:
Atlantic Sea Island Group LLC

NOTE TO READER

This appendix contains the **Air Quality Evaluation and Modeling Protocol** submitted to the U.S. Environmental Protection Agency (EPA) Region 2 and the New York State Department of Environmental Quality (NYSDEC) in **September of 2006**. Also contained in this appendix is a February 13, 2007 addendum letter to the September 2006 protocol.

The September protocol has been included here only for historical purposes to illustrate that the project modeling approach was presented formally to the regulators and to show the feedback on the proposed approach from the regulators.

The September 2006 protocol represents an update to a prior version of the protocol (April 2006) to address EPA and NYSDEC comments shown in Appendices A-1, A-2, and A-3 of the protocol. In addition, EPA Region 2 has provided comments on the September 2006 protocol and February addendum. Atlantic Sea Island Group LLC's responses to EPA's comments and the EPA comment letter are contained Volume Two, Exhibit X - Preconstruction Air Permit, Appendix D.

The project design has progressed since the September 2006 protocol so some of the information contained in the Project Overview and Source Description sections of the protocol and Figure 2-1are no longer accurate. In addition, the regulatory applicability section and modeling results sections of this protocol have been superseded

All current project-related data and figures are contained in updated sections in Exhibit X (the Preconstruction Air Permit Application) and Volume Three, Part One - Topic Report 8.

Air Quality Evaluation and Modeling Protocol

Safe Harbor Energy

September 2006

Appendix A-1

L. Sedefian of New York State Department of Environmental Conservation (NYSDEC) to F. Pope of ENSR Corporation dated May 9, 2006

New York State Department of Environmental Conservation
Division of Air Resources
Bureau of Stationary Sources, 2rd Floor
625 Broadway, Albany, New York 12233-3254
Phone: (518) 402-8403 • **FAX:** (518) 402-9035
Website: www.dec.state.ny.us

Denise M. Sheehan
Commissioner

May 9, 2006

Mr. Frederick B. Pope
Senior Regional Program Manager
ENSR Corporation
2005 Cabot Blvd., Suite 100
Langhorne, PA 19047-1810

Dear Mr. Pope,

I have reviewed the *Air Quality Evaluation and Modeling Protocol* submitted on 4/16/06 for the proposed LNG terminal facility known as Safe Harbor Energy Project in waters south of Long Island, N.Y. As noted in the protocol, certain emissions (e.g. LNG tanker emissions) and physical parameters (e.g. stack height) are still to be finalized. In addition, it is asserted that certain EPA regulations such as PSD are not applicable to the project. I have not reviewed the emissions data and defer to EPA Region II on the determination of PSD and other regulatory applicability and, to the extend that there are final emissions and determinations which effect the protocol and the air quality assessments, a revised protocol should be submitted.

In the meantime, I will provide comments and recommendations on the proposed modeling methodologies and related regulatory references in the protocol:

1) We recommend that an assessment of the accidental release of contained ammonia be done in the Environmental Assessment document (as noted in Section 3.6.1) even if the percent concentration is just below the Section 112(r) threshold. Also, we presume particulate emissions contain condensible materials regardless of the Subpart 227-1 limits noted in Section 3.8.2 and that the regulatory thresholds noted in Section 3.9 for Ozone nonattainment should be the current values until Subpart 231-2 is officially revised. Lastly, the annual impact threshold for PM2.5 noted in Section 3.11 and Table 4-1 should be 0.3 and not 1.0 ug/m^3 per our Commissioner's Policy CP-33.

2) For offshore sources, Section 6 of EPA modeling guidelines recommends the use of the OCD model and not AERMOD, as proposed in Section 4.0 of the protocol. Thus, all near field impacts should be based on OCD predictions. However, for the calculation of structure downwash effects on the plume, the AERMOD model should be used for determination of close in impacts since the OCD model's downwash algorithm does not include the latest recommended formulations, nor all potential structure effects.

3) The reference to IMPASS model in Sections 4.0 and 4.2.4 should be corrected to INPUFF and the purpose of the latter and it's approach should be detailed.

4) For the proper application of the OCD model, the mandatory meteorological parameters should be collected with better than 90% recovery rate. Based on the data recovery rates presented in Tables 4-5 and 4-6 for the Buoy 44025 and Ambrose Light stations, respectively, we agree that the former contains much more useable data especially for the necessary temperatures. As such, we believe that an adequate data base can be generated for the years 1999, 2002, and 2003-2005, instead of the proposed consecutive 2001-2005 period. We do not recommend substitution of JFK dew point data for the year 2001 as proposed (or any other year) since there could be significant differences from over water conditions. In addition, there do not appear to be any years in which Ambrose Light data can be augmented with adequate dew point data from Buoy 44025 which would render the former site more desirable. We request that a wind rose comparison of the years noted above be made between the Buoy 44025 and Ambrose light data.

Prior to approval of the specific data base for use in all modeling assessments, however, we need the following details on the data collected and the instrumentation: a)comparison of the instrument specifications and thresholds to those recommended in EPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications* document (EPA-454/R-99-005, revised February 2000) and quality assurance procedures used in collecting the data; and b) description of the sampling rates and averaging times for each parameter.

5) The receptor grid proposed in section 4.4 beyond the "safety zone" should be modified to be refined down to a 100m interval, not 250m. In addition, receptors at the boundary of the "ambient air" distance from the facility should be further refined to assure a radial distance corresponding to no larger than a 10 degree interval. Lastly, receptors should be placed at the nearest shoreline distances along New York.

6) Any operational restrictions noted in Section 4.5 which are used in the model calculations will become permit restrictions and, thus, should be better defined.

7) If modeling results confirm the preliminary impacts above significance levels, a cumulative assessment will be necessary in accord with DEC program policy DAR-10 and Air Guide- 36.

If you have any questions, please let me know.

Sincerely

Leon Sedefian
Air Pollution Meteorologist V
Division of Air Resources

cc: J. Ferguson, W. Little R. Orr
A. Coulter, EPA Region II

Appendix A-3

Summary of June 5, 2006 Conference Call with NYSDEC

(Draft 06/08/06)

Safe Harbor Energy

Air Quality Evaluation and Modeling Protocol

Discussion with NYSDEC Staff on June 5th Call

Attendees: L Sedefian and P Galvin – NYSDEC
G Almquist, R Hessel and F B Pope - SHE

The following items, some referenced to NYSDEC's May 9th correspondence, were discussed during the call:

Meteorological Database

- Consensus was reached that meteorological data from Buoy 44025 will be used for input to the air quality modeling. The years 1999, 2002 through 2005 will comprise the 5 year database. Data for year 2003 will be supplemented by substituting Ambrose Light data for missing periods of meteorological parameters. Since January 1 through 26 are missing meteorological data in 1999, data for January 2000 will be substituted such that the annual cycle will run February 1999 through January 2000. Since the database is not consecutive nor purely Buoy 44025 data, the highest modeled impacts will be presented for comparison with SILs, ambient standards and possibly other regulatory levels (as opposed to the highest-2nd highest modeled impacts for ambient standards if an appropriate meteorological database was available).

- NYSDEC indicated that the sensor thresholds and specifications, the sampling techniques and averaging periods, and the quality control procedures for the Buoy data were acceptable based on an initial review of the information obtained from the National Data Buoy Center and provided to NYSDEC. In addition, NYSDEC acknowledged that the windroses provided for Buoy 44025 and Ambrose Light are similar including the relatively low frequency of calm conditions.

- NYSDEC recommended that the AERMOD model be run for downwash and that the mixing heights specified by AERMOD be used as input to the OCD model as opposed to using OCD default mixing height values. NYSDEC noted that the USEPA is investigating the use of mixing heights generated by CALMET. This discussion failed to identify the suitable upper air station (Atlantic City or Brookhaven). Based on a previous project, Brookhaven upper air may be more appropriate.

Inventory of Major SO_2 Sources

SHE requested an SO_2 inventory from NYSDEC that would apply to a new source that had significant impacts but did not trigger a PSD analysis (Guidance in AG-36). Specifically, the SEF project inventory (a former Article X power project in NYC that had an approved AG-36 inventory) was requested. NYSDEC committed to providing an SO_2 inventory of other major sources and suggested that SHE contact New Jersey DEP for major SO_2 sources in NJ. NYSDEC suggested that a demonstration of non-significant concentration gradients in the Project SIA may eliminate the need to model mainland based SO_2 sources.

PM2.5 Policy

NYSDEC stated that the NYS policy guideline of 0.3 ug/m^3 annual impact should be used as the SIL for the PM2.5 modeling analysis. NYSDEC also indicated that the policy may not apply at the island location and the

offshore area at the Island location may not need to be considered nonattainment for PM2.5. USEPA should make the determination on both these matters.

NYSDEC Information Request

NYSDEC requested the following information as well during the call:

- The contact for the National Data Buoy Center;
- Wind roses for Buoy 44025 and Ambrose Light for 1999, 2003 and 2004 (when both stations have > 90 percent recovery); and
- An updated protocol document containing all changes generated in response to NYSDEC and USEPA comments including more details on the sources modeled for the NEPA analysis, information as discussed about the meteorological database and the use of the INPUFF model.

USCG Comment #22:

Tables 2.5b and 2.5c of the modeling protocol and Attachment 2.1 (General Conformity) of Volume 5 show relatively large emissions of certain pollutants from the tugs while at berth and during LNG unloading. On the other hand, Tables 3-5 to 3-7 of the permit application document do not include these emissions as part of the facility, nor are these included in the modeling results of Table 6-4 of the application.

For a complete analysis, please include the ambient air quality impacts from all the Project's emissions, which include emissions from the carriers and tugs, when stationary, to be addressed for air quality analysis purposes. This requirement is consistent with similar guidance in EPA's Draft 1990 NSR Workshop Manual (Section A.II.B.4, Secondary Emissions), and pursuant to 6NYCRR Subparts 200.6 and 257. Ambient concentrations of criteria air pollutants will be impacted by the Project and must be evaluated for compliance with the NAAQS. All emissions must be included in the NAAQS analysis and discussed in terms of backup information and possible mitigation.

Response:

ASIG has requested a meeting with EPA to discuss this comment. After consultation with EPA, a response will be provided.

USCG Comment #23:

Section 3 of the permit application indicates that the particulate emissions from the generators include only the filterable portion; the application states this is per EPA policy. This is inaccurate: to the contrary, EPA has indicated that PM10 emissions must include condensibles. EPA is yet to finalize their new source review regulations for PM2.5, but EPA's final SIP rule for fine particulates indicates that for the purposes of developing emission inventories and attainment demonstrations, the condensable fraction should be included. As EPA notes, this is especially important for combustion sources. Thus, the condensable portion of the PM10 and PM2.5 emissions need to be included with the filterable emissions for the purpose of both applicability and impact analysis.

In addition, section 3.2 of the application does not indicate whether the PM emissions from oil firing in the vessels include condensables. If not, this correction must be made to the vessel unloading emissions as well.

Response:

We are aware that historically EPA has required that PM emissions quantification include so-called "condensable" emissions measured per EPA Method 202, and in all cases where EPA PM emission factors were referenced, we utilized the sum of the filterable and condensable factors (or, in the case of the gas engine generators, we conservatively estimated twice that sum). However, EPA has also more recently recognized that there are concerns with this measurement method and the degree to which its results can be used for purposes of determining ambient PM impacts. Most recently, EPA's finalization of $PM_{2.5}$ nonattainment NSR regulations (73 FR 28321, May 16, 2008, see Attachment 23-1) states that

> "In recognition of...concerns [regarding measurement methods for condensable PM emissions and other issues surrounding condensable PM], both as they apply to the NSR program and the broader air program, we have adopted a transition period during which NSR permits need not address limits of condensable $PM_{2.5}$ emissions." (73 FR 28335, May 16, 2008)

For commercial marine vessels, PM emission factors were from "The New York, Northern New Jersey, Long Island Nonattainment Area Commercial Marine Emissions Inventory" (Starcrest Consulting Group, 2003). Although the extent to which condensables are or aren't included is not specifically identified, we understand that these factors are being used by NYSDEC for its emissions inventory and are therefore the most appropriate ones to use.

Attachment 23-1

- EPA 73 FR 28334 - 73 FR 28335

programs are subject to notice and comment rulemaking procedures.

Numerous commenters supported our proposal to set significant emissions rates for $PM_{2.5}$ precursors at the levels already used for other purposes in the NSR program. One commenter indicated that since roughly half or more of ambient $PM_{2.5}$ is derived from precursors, 10 tpy would be an appropriate significant emissions rate for $PM_{2.5}$ precursor emissions. Another commenter suggested a significant emissions rate of 4 tpy for SO_2 and 2 tpy for NO_X, based on the percentage of $PM_{2.5}$ that is typically derived from these precursors and the ratios between the existing significant emissions rates for these pollutants and the SO_2 and NO_2 annual NAAQS. Since the ambient concentrations of $PM_{2.5}$ vary across the country and since significant emissions rates have not been developed as a ratio of the NAAQS, we do not believe that the suggested approach is appropriate.

As discussed in the proposal, the use of existing significant emission rates where the $PM_{2.5}$ precursor is also regulated under NSR as a separate criteria pollutant harmonizes the NSR program for $PM_{2.5}$ with the NSR programs for those other criteria pollutants. This enables a source to determine the NSR impacts of proposed modifications by reference to a single significant emissions rate for each pollutant, and enables streamlining of determinations regarding the applicable control technology and analysis of air quality impacts into a single and comprehensive decision making process for both $PM_{2.5}$ and other criteria pollutants that also cover $PM_{2.5}$ precursors. This also follows precedent. When ozone became a criteria pollutant, EPA used the NO_X significant emissions rate from the NO_2 program.

The burden imposed is not the only factor to consider when setting the significant emission rates for precursors—the process for determining the significant emission rates must also take into account the accuracy and certainty with which we can predict the effect of the precursors on $PM_{2.5}$ concentrations. It is difficult to determine the ambient air quality effects that result from a single source of emissions of $PM_{2.5}$ precursors. There are conservative screening models for predicting impacts of large NO_X and SO_2 sources on ambient $PM_{2.5}$ concentrations. We conducted a range of modeling analyses to determine the amount of $PM_{2.5}$ precursor emissions needed to show an increase in ambient $PM_{2.5}$ concentrations. These analyses showed that precursor emissions probably have some localized impacts, but that most impact is farther downwind as precursors have the time to convert to $PM_{2.5}$. In addition, the modeling available at this time does not provide sufficient information to estimate impacts of emissions from individual sources of ammonia and VOC on ambient $PM_{2.5}$ concentrations. While we know that precursors contribute to the formation of $PM_{2.5}$ in the ambient air, the degree to which these individual precursors contribute to $PM_{2.5}$ formation in a given location is complex and variable. There are competing chemical reactions taking place in the atmosphere, and meteorological conditions play a significant role in the size and characteristics of particle formation. For these reasons, we do not believe that we have adequate data on the impacts of precursor emissions from individual sources to override the administrative advantages of setting the significant emissions rates for SO_2, NO_X, and VOC for purposes of the $PM_{2.5}$ NSR program at the same levels that are already used for other purposes in the major NSR program.

E. Condensable PM Emissions

In this final NSR rule, EPA will not require that States address condensable PM in establishing enforceable emissions limits for either PM_{10} or $PM_{2.5}$ in NSR permits until the completion of a transition period, as described herein. In response to significant comments on the variability of test methods available for measuring condensable emissions, we have adopted this transition period approach to allow us to assess the capabilities of the test methods and possibly revise them to improve performance. The transition period will end January 1, 2011 unless EPA advances this date through the rulemaking process described below.

Subsequent to the completion of the test methods assessment, EPA will be conducting a notice and comment rulemaking to codify new or revised test methods. Once these new or revised test methods are in place, States will have the tools necessary to issue NSR permits addressing condensable PM. Thus, as part of the test methods rulemaking, we will take comment on an earlier closing date for the transition period in the NSR program if we are on track to meet our expectation to complete the test methods rule much earlier than January 1, 2011. In the meantime, however, we are establishing January 1, 2011 as the latest possible end date for the NSR transition period because this is also the end of the transition period for SIP purposes as described in the Clean Air Fine Particle Implementation Rule (*see* section II.L in 72 FR 20586, April 25, 2007). Prevention of Significant Deterioration and NA NSR permits issued after the effective date of this NSR implementation rule but prior to the end of the transition period for the NSR program are not required to account for condensable emissions in $PM_{2.5}$ or PM_{10} emissions limits. After January 1, 2011 (or any earlier date established in the upcoming rulemaking codifying test methods), EPA will require that NSR permits include limits of condensable emissions, as appropriate. Prior to this date, States are not prohibited from establishing emissions limits in NSR permits that include the condensable fraction of direct $PM_{2.5}$.

As noted in the proposal preamble, certain commercial or industrial activities involving high temperature processes (*e.g.*, fuel combustion, metal processing, and process cooking operations) emit gaseous pollutants into the ambient air, some of which rapidly condense into particle form. The constituents of these condensed particles include, but are not limited to, organic materials, sulfuric acid, and metals and metal compounds. We consider such condensable emissions to be a component of direct PM emissions. Specifically, direct PM emissions consist of both the ''filterable fraction'' which already exist in particle form at the elevated temperature of the exhaust stream, and the ''condensable fraction'' which exist in gaseous form under exhaust stream conditions but condenses rapidly in the ambient air.

Because condensable PM emissions exist almost entirely in the 2.5 micrometer range and smaller, these emissions are inherently more significant for $PM_{2.5}$ than for prior PM standards addressing larger particles. Condensable PM emissions commonly make up a significant component of direct $PM_{2.5}$ emissions. Therefore, we believe that it is important that the air quality management of PM promote a comprehensive approach to the control of condensable PM.

We proposed on November 1, 2005 to clarify that condensable PM emissions must be included when determining whether a source is subject to the major NSR program. We noted in the proposal that our prior guidance [12] had clarified that PM_{10} includes condensable PM and

[12] Leter from Thompson G. Pace, Acting Chief, Particulate Matter Programs Branch, to Sean Fitzsimmons, Iowa Department of Natural Resources (Mar. 31, 1994) (available at *http://www.epa.gov/Region7/programs/artd/air/nsr.nsrmemos/cpm.pdf* and in the docket for this rulemaking, Docket ID No. EPA–HQ–OAR–2003–0062).

that, where States expect condensable PM emissions to be in higher amounts, States should use methods that appropriately measure condensable PM emissions. In addition, we pointed out that the 2001 consolidated emissions reporting rule (CERR) requires States to report condensable emissions in each inventory revision (*see* 67 FR 39602, June 10, 2001) and that Method 202 in appendix M of 40 CFR part 51 quantifies condensable PM. We also noted that States have not applied this existing guidance consistently.

We received a number of comments on whether NSR programs should account for condensable PM emissions in light of the current state of knowledge of and uncertainties around the measurement of direct $PM_{2.5}$. Several commenters supported our proposal to require the inclusion of condensable PM emissions in NSR applicability determinations. On the other hand, several other commenters expressed opposition to including condensables at this time and raised concerns about the availability and implementation of test methods and related issues about the uncertainties in existing data for condensable $PM_{2.5}$. As a result of the concerns, these commenters believed EPA would be premature in requiring a comprehensive evaluation of condensable $PM_{2.5}$, especially as it related to developing any new emissions limits for stationary sources.

One commenter noted that regulation of condensable PM at this time will impede, rather than facilitate, expeditious attainment of the $PM_{2.5}$ standard. Another commenter expressed concern about the potential for retroactive enforcement over applicability decisions made in good faith, and for retroactive application of the new test method to assert violations of an emission limit, where the applicability decision or the emission limit was originally based on flawed testing/estimating methodology. Several commenters raised serious concerns about the availability and implementation of accurate test methods and emissions factors for condensable $PM_{2.5}$. They further stated that regulation of condensable $PM_{2.5}$ emissions would be appropriate only after we have developed a workable transitional strategy that ensures existing major sources are not placed in ''NSR jeopardy'' for physical and operational changes undertaken before new test methods and other requirements for condensable $PM_{2.5}$ are established.

In recognition of these concerns, both as they apply to the NSR program and the broader air program, we have adopted a transition period during which NSR permits need not address limits of condensable $PM_{2.5}$ emissions. During this transition period, EPA will undertake a collaborative testing effort with industry, National Association of Clean Air Agencies (NACAA), and other stakeholders to assess and improve the effectiveness and accuracy of the available or revised test methods. The purpose of the stakeholder testing projects will be to collect new direct filterable and condensable $PM_{2.5}$ emissions data using methodologies that provide data more representative of sources' direct $PM_{2.5}$ emissions. The EPA, States, and others will use these data to establish or improve emissions factors and to define more representative source emissions limits in permits.

The EPA acknowledges the legitimate concerns raised by commenters concerning potential exposure to retroactive enforcement and has established rules to address this issue. The EPA will not revisit applicability determinations made in good faith prior to the end of the transition period, insofar as the quantity of condensable PM emissions are concerned, unless the applicable implementation plan clearly required consideration of condensable PM. Likewise, EPA will interpret PM emissions limitations in existing permits or permits issued during the transition period as not requiring quantification of condensable $PM_{2.5}$ for compliance purposes unless such a requirement was clearly specified in the permit conditions or the applicable implementation plan.

After the end of the transition period (January 1, 2011 or any earlier date established in the upcoming rulemaking codifying test methods), EPA will require that all NSR applicability determinations for $PM_{2.5}$ and PM_{10} address condensable emissions as applicable, and the source may not rely on calculations made for previous determinations that did not include an accurate accounting of condensables. Additionally, compliance with these limits must be determined using the promulgated validated test methods that are applicable after that date. Moreover, after that date, we expect that condensable PM emissions will be addressed in all other aspects of the major NSR program, such as impact analyses under PSD and offsets under NA NSR. *See* 72 FR 20586, April 25, 2007 for the discussion of the transition period as it applies to the other elements of the air program in the final Clean Air Fine Particle Implementation Rule.

Although EPA is not requiring that State NSR programs address condensable emissions of PM until the end of the transition period, States that have developed the necessary tools are not precluded from acting to measure and control condensable PM emissions in NSR permit actions prior to the end of the transition period, especially if it is required in an applicable SIP. To the extent that a State has the supporting technical information and test methods, the State may assess the capabilities of current control technologies, possible modifications to such technologies, or new technologies as appropriate relative to control of condensable $PM_{2.5}$ emissions. As an example, a specific approach for controlling condensable PM could be a change in control device operating temperature to improve emissions reductions. We also note that it is important that implementation of any new or revised emissions limits and test methods that account for condensable emissions should be prospective and clearly differentiated from existing NSR permit requirements. This will avoid confusion over the compliance status relative to existing PM emissions limits that were not developed considering the condensable portion.

Notwithstanding the issues and uncertainties related to condensable PM, we encourage States to begin immediately to identify measures for reducing condensable PM emissions in major NSR permit actions, particularly where those emissions are expected to represent a significant portion of total PM emissions from a source.

F. Prevention of Significant Deterioration (PSD) Program Requirements

To receive a permit for a new major source or a major modification, sources subject to PSD must:

- Install Best Available Control Technology (BACT).
- Conduct air quality modeling to ensure that the project's emissions will not cause or contribute to either—

—A violation of any NAAQS or maximum allowable pollutant increase (PSD increment); or

—An adverse impact on any Class I area ''air quality related value'' (AQRV).

- As required, comply with preconstruction monitoring requirements.

This final action regarding each of these elements is discussed in the following sections.

USCG Comment #24:

For demonstration of NAAQS compliance, Table 6-4 and 6-5 of Exhibit X indicate that PM10 compliance is used as a surrogate for PM2.5 NAAQS compliance. An explicit demonstration of PM2.5 compliance must be made, including the revised 24 hour standard for PM2.5. As indicated in the application, EPA is treating the Project area as if in nonattainment for PM2.5; thus, at a minimum, a modeled demonstration of compliance of the PM2.5 NAAQS from the Project must be shown.

Section 4.5.8.12 of the permit application notes that DEC staff had asked for implementation of Commissioner's policy on fine particulates (CP-33). Although Safe Harbor believes CP-33 does not apply to their project, impacts relative to the significance levels in CP-33 are nonetheless presented in Tables 6-4 and 6-5. These tables note that the impacts are below CP-33 levels only for the "terminal emission" and excluding the tankers. CP-33 requires the inclusion of all sources, including mobile sources in its implementation. Thus, Safe Harbor should provide revised impacts and address the minimization of particulate emissions from the project.

Response:

ASIG has requested a meeting with EPA to discuss this comment. After consultation with EPA, a response will be provided.

USCG Comment #25:

Section 4.4 of Exhibit X and Topic Report 8, section 8.1.1, in Volume 3 indicate that there will be limitations on the fuel sulfur content used by the LNG carriers and the types of carriers used for the project in order to keep emissions below the PSD thresholds. Safe Harbor should provide detailed description as to how these requirements will be monitored and demonstrated, given that the certain maritime requirements which the U.S. recognizes (e.g. IMO Annex VI) allow for much higher sulfur contents for the fuels used by vessels.

Response:

In cooperation with LNG vessel operators, ASIG will request records with respect to which fuels are fired by the vessels within the Safety Zone and will ask for fuel sulfur content analyses.

USCG Comment #26:

Section 5.1 of Exhibit X summarizes the nonattainment area requirements of Subpart 231-2.4(a)(2) with respect to alternative sites, sizes, and production processes and refers to Topic Report 9 in Volume 3 and Exhibit F of Volume 2 for more details on the alternatives and site selection criteria. These latter sections do not provide any additional information pertinent to air quality aspects of the project, nor with respect to the nonattainment requirements.

A detailed discussion should be presented in conformance with the "Three Prong" test used by DEC. The Interim Decision may be viewed on DEC's website at www.dec.ny.gov/hearings/ 11477.html.

Response:

ASIG has requested a meeting with EPA to discuss this comment. After consultation with EPA, a response will be provided.

USCG Comment #27:

Sections 6.4.4 and 6.4.5 of Exhibit X note that sample model outputs are provided in Appendix D.2 and D.3. All input and output files, including raw meteorological data used to generate AERMET and OCD input files, should be provided on a File or similar medium for review to assure projected impacts have been properly calculated.

Response:

Input and output files from AERMOD and OCD as well as the processed meteorological data will be provided on disk to EPA.

USCG Comment #28:

The General Conformity applicability evaluation is based on the 8-hr ozone nonattainment classification of moderate and the associated conformity thresholds for VOC and NOx of 100 tpy. In accordance with a December 22, 2006 US Court of Appeals decision (South Coast Air Quality Management District v. EPA, 472 F.3d 882 (D.C. Cir. 2007)), this document should reflect the 1-hr severe ozone nonattainment classification and the general conformity thresholds for NOx and VOC of 25 tpy.

The conformity discussion also separates the Project as emissions within 3 miles of shore and the safe zone (location of the island). NYSDEC believes the entire Project falls within the NYMA nonattainment area. Please provide the basis for your 3 mile determination.

Response:

The referenced Court of Appeals decision addressed transportation conformity (40 CFR 93, Subpart A), not general conformity (40 CFR 93, Subpart B). ASIG's consultant Tetra Tech spoke with EPA's General Conformity authority, Tom Coda, who confirmed that this is the case.

With respect to the geographic boundaries: three miles from shore is the state territorial boundary, and is also the boundary for the emissions inventory for commercial marine vessels that NYSDEC uses for its State Implementation Plan. The determination that the geographic boundaries include 3 miles from shore and the safety zone is consistent with past EPA general conformity determinations for the Northeast Gateway and Neptune projects off Massachusetts. For example, in EPA Region 1's November 22, 2006 comments on the Northeast Gateway Deepwater Port FEIS, EPA notes that for the general conformity determination,

> "The project emissions of concern are those occurring onshore in the 8-hour ozone nonattainment area, emission in Massachusetts' State territorial waters (adjacent to the designated nonattainment area), and emissions within the safety area (500 meters around the loading buoys)." (Varney 2006)

Pertinent supporting materials are included in Attachment 28-1 and 28-2.

References:

Varney, R.W. 2006. "Additional Comments on the Northeast Gateway Deepwater Port FEIS," enclosure to letter from Robert W. Varney (Regional Administrator, EPA Region 1) to Mark A. Prescott (USCG Deepwater Ports Standards Division), November 22, 2006.

Attachment 28-1

- December 22, 2006 US Court of Appeals Decision (South Coast Air Quality Management District v. EPA, 472 F.3d 882 (D.C. Cir. 2007))

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472 F.3d 882

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT, Petitioner
v.
ENVIRONMENTAL PROTECTION AGENCY, Respondent
National Environmental Development Association's Clean Air Regulatory Project, et al., Intervenors.

No. 04-1200.

No. 04-1201.

United States Court of Appeals, District of Columbia Circuit.

Argued October 12, 2006.
Decided December 22, 2006.

COPYRIGHT MATERIAL OMITTED COPYRIGHT MATERIAL OMITTED On Petitions for Review of a Final Rule of the Environmental Protection Agency.

David S. Baron argued the cause for the Environmental petitioners and South Coast Air Quality Management District. With him on the briefs were Howard I. Fox, Ann B. Weeks, Jonathan F. Lewis, Barbara B. Baird, and Adam Babich. Kurt R. Wiese entered an appearance.

William L. Pardee, Assistant Attorney General, Attorney General's Office of Commonwealth of Massachusetts, argued the cause for petitioner Commonwealth of Massachusetts, et al. With him on the briefs were Thomas F. Reilly, Attorney General; Richard Blumenthal, Attorney General, Attorney General's Office of the State of Connecticut, Kimberly Massicotte and Matthew Levine, Assistant Attorneys General; Carl Danbert, Attorney General, Attorney General's Office of the State of Delaware, Valerie S. Csizmadia, Deputy Attorney General; G. Steven Rowe, Attorney General, Attorney General's Office of the State of Maine, Gerald D. Reid, Assistant Attorney General; Robert J. Spagnoletti, Attorney General, Attorney General's Office of the District of Columbia, Todd S. Kim, Solicitor General, Edward S. Schwab, Deputy Attorney General, Donna M. Murasky, Senior Litigation Counsel; Eliot Spitzer, Attorney General, Attorney General's Office of the State of New York, J. Jared Snyder, David A. Munro, and Lisa S. King, Assistant Attorneys General; and Robert A. Reiley, Counsel, Commonwealth of Pennsylvania, Department of Environmental Protection.

John K. McManus, Assistant Attorney General, Attorney General's Office of State of Ohio, argued the cause for petitioner State of Ohio. With him on the briefs was Dale T. Vitale, Assistant Attorney General.

Frank S. Craig, III argued the cause for the Industry petitioners. With him on the briefs were Charles H. Knauss, Robert V. Zener, John B. King, Steven J. Levine, and Patrick O'Hara.

David J. Kaplan, Attorney, U.S. Department of Justice, argued the cause for

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respondent. With him on the brief were John C. Cruden, Assistant Attorney General, Natalia T. Sorgente, Attorney, and Jan M. Tierney, Attorney, U.S. Environmental Protection Agency. Eric G. Hostetler, Attorney, U.S. Department of Justice, entered an appearance.

David S. Baron and Howard I. Fox were on the brief of the Environmental intervenors.

Charles H. Knauss, Leslie S. Ritts, Lorane F. Hebert, Norman W. Fichthorn, Lucinda Minton Langworthy, Allison D. Wood, Leslie A. Hulse, Richard S. Wasserstrom, Maurice H. McBride, Ralph J. Colleli, M. Elizabeth Cox, Jan S. Amundson, and Quentin Riegel were on the brief of the Industry intervenors in support of Respondent.

Frank S. Craig, III, John B. King, Geraldine E. Edens, and Frederick R. Anderson were on the brief of amici curiae The Chamber of Greater Baton Rouge, et al. in support of Respondent.

Before: HENDERSON, ROGERS and BROWN, Circuit Judges.

Opinion for the Court filed by Circuit Judge ROGERS.

ROGERS, Circuit Judge.

This case consolidates challenges to the Final Phase 1 Rule To Implement the 8-Hour Ozone National Ambient Air Quality Standard, 69 Fed.Reg. 23,951 (Apr. 30, 2004) (codified at 40 C.F.R. parts 40, 51, 81) (hereinafter "2004 Rule"), promulgated by the Environmental Protection Agency pursuant to the Clean Air Act ("CAA" or "the Act"), 42 U.S.C. § 7401 *et seq*. Because EPA has failed to heed the restrictions on its discretion set forth in the Act, we grant the petitions in part, vacate the rule, and remand the matter to EPA for further proceedings.

I.

2 The earliest clean air laws date back to the nineteenth century, when industrial cities sought to reduce smoke emissions. *See* GARY C. BRYNER, BLUE SKIES, GREEN POLITICS: THE CLEAN AIR ACT OF 1990 AND ITS IMPLEMENTATION 98 (2d ed.1995). It was not until much later that the federal government became involved. The first Clean Air Act was passed in 1963, *see* Pub.L. No. 88-206, 77 Stat. 392 (1963), but this effort, supplying little more than research funding, bore little resemblance to the comprehensive scheme that Congress would later impose.

3 The Clear Air Act Amendments of 1970 introduced the now-familiar arrangement of state-federal cooperation. *See* Clean Air Act Amendments of 1970, Pub.L. No. 91-604, 84 Stat. 1676 (1970). EPA was to prescribe a primary national ambient air quality standard ("NAAQS") for airborne pollutants that was "requisite to protect the public health." *Id*. § 4(a), 84 Stat. at 1678-80 (codified at 42 U.S.C. § 7409). The NAAQS was to be attained by a state implementation plan ("SIP"), developed by the state and approved by EPA, that introduced sufficient pollution control techniques so as to reach attainment by 1975, with the possibility of a one-time extension of two more years. *Id*. § 4(a), 84 Stat. at 1680-82 (codified at 42 U.S.C. § 7410 (amended 1977)). This approach, which applied identically to all "criteria" pollutants, proved overly ambitious. Congress amended the Act in 1977, extending the attainment deadlines until December 31, 1987. Pub.L. No. 95-95, § 129(b), 91 Stat. 685, 746-47 (codified at 42 U.S.C. § 7502(a)(2) (amended 1990)).

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With the new deadline approaching and penalties looming for states yet to attain, Congress stepped in again. By this time, Congress was considering new approaches to deal with unclean air. *See* Henry A. Waxman, *An Overview of the Clean Air Act Amendments of 1990,* 21 ENVTL. L. 1721, 1731-33 (1991) (hereinafter "*Overview*"). The existing approach, which specified the ends to be achieved but left broad discretion as to the means, had done little to reduce the dangers of key contaminants. For example, Don Theiler, Director of the Wisconsin Bureau of Air Management, appearing on behalf of two national associations of state-and-local air-control agencies, testified that between August 1987 and February 1989, the number of areas violating the ozone NAAQS had increased, from seventy to ninety, exposing as many as 95 million people to unhealthy levels of ozone. *See Clean Air Act Standards: Hearing Before the Subcomm. on Health and the Environment of the H. Comm. on Energy and Commerce,* 101st Cong. 30 (1989). In light of such failures, Congress culminated nearly ten years of hearings and debates by enacting the 1990 Amendments to the Act. Pub.L. No. 101-549, 104 Stat. 2399 (Nov. 15, 1990). This version of the Act provides the backdrop for the petitions before the court.

The 1990 Amendments abandoned the discretion-filled approach of two decades prior in favor of more comprehensive regulation of six pollutants that Congress found to be particularly injurious to public health: ozone, carbon monoxide, small particulate matter, sulfur dioxide, nitrogen dioxide, and lead. *See* CAA §§ 181-192, 42 U.S.C. §§ 7511-7514a. The old ends-driven approach that had proven unsuccessful for these pollutants was redesignated Subpart 1 (of Part D of Title I), which Congress instructed "shall not apply with respect to nonattainment areas for which attainment dates are specifically provided under other provisions of this part." CAA § 172(a)(2)(D), 42 U.S.C. § 7502(a)(2)(D). In place of Subpart 1, Congress enacted Subpart 2 to deal with the specific problem of ozone. *See* CAA §§ 181-185B, 42 U.S.C. §§ 7511-7511f. Ozone, an essential presence in the atmosphere's stratospheric layer, is dangerous at ground level. There, ozone is formed by the chemical reaction of nitrogen oxides ("NO_x") with any of a number of volatile organic compounds ("VOCs"), in the presence of sunlight. *See West Virginia v. EPA,* 362 F.3d 861, 865 (D.C.Cir.2004). Ground-level ozone is a key component of urban smog and exposure to high concentrations "can cause lung dysfunction, coughing, wheezing, shortness of breath, nausea, respiratory infection, and in some cases, permanent scarring of the lung tissue." *Overview, supra,* at 1758; *see* S. REP. No. 101-228, at 6 (1989), *reprinted* in 5 COMM. ON ENV'T & PUB. WORKS, U.S. SENATE, A LEGISLATIVE HISTORY OF THE CLEAN AIR ACT AMENDMENTS OF 1990, at 8338, 8346 (hereinafter "LEGISLATIVE HISTORY").

No longer willing to rely upon EPA's exercise of discretion, Congress adopted a graduated classification scheme that prescribed mandatory controls that each state must incorporate into its SIP. Thus, as of the date of enactment of the 1990 Amendments, areas failing to reach attainment under the NAAQS would become, upon such designation by EPA, subject to Subpart 2 requirements by operation of law. *See* CAA § 181(a)(1), 42 U.S.C. § 7511(a)(1). Under Subpart 2, each area was to be classified according to its design value—the measured concentration of ground-level ozone. The statutory Table 1 provided that areas were to be classified as Marginal, Moderate, Serious, Severe, or Extreme depending upon how much the design value exceeded the NAAQS at the time of designation. CAA § 181(a) tbl.1, 42 U.S.C. § 7511(a) tbl.1. Areas with greater problems were given more time to attain the NAAQS but a harsher set of mandatory controls, including provisions for demonstrations of reasonable further progress, NO_x control, motor vehicle emissions control, and new source review. *See* CAA § 182, 42 U.S.C. § 7511a. Areas that failed to meet a deadline were to be reclassified to a higher classification automatically, thereby according

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more time to comply with the NAAQS while subjecting that area to more stringent mandatory controls. CAA § 181(b)(2), 42 U.S.C. § 7511(b)(2). This protocol was prescribed whether or not that area was closer to attainment when it missed the deadline than when it was originally classified. For Severe and Extreme areas that still had not reached attainment by November 15, 2005 or 2010, respectively, the Act called for the imposition of penalties to provide incentives for major polluters to reduce VOC emissions. *See* CAA § 185, 42 U.S.C. § 7511d. Under the 1990 Amendments, the NAAQS stood at 0.12 parts per million ("ppm"), measured as the maximum average concentration for a one-hour period during a calendar year. *See* 40 C.F.R. § 50.9(a) & app. H. This regulatory scheme remained in place until 1997.

Although Subpart 2 of the Act and its Table 1 rely upon the then-existing NAAQS of 0.12 ppm, measured over a one-hour period, elsewhere the Act contemplates that EPA could change the NAAQS based upon its periodic review of "the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health" that the pollutant may cause. CAA §§ 108(a), 109(d), 42 U.S.C. §§ 7408(a), 7409(d). The Act provides that EPA may relax a NAAQS, but in so doing, EPA must "provide for controls which are not less stringent than the controls applicable to areas designated nonattainment before such relaxation." CAA § 172(e), 42 U.S.C. § 7502(e). This provision protects against backsliding.

In 1997, citing a new scientific understanding that prolonged ozone exposure was more harmful to public health than the short-term exposure then regulated, EPA promulgated a rule setting a new NAAQS for ambient ozone. *See* NAAQS for Ozone, 62 Fed.Reg. 38,856 (July 18, 1997) (codified at 40 C.F.R. §§ 50.9, 50.10) (hereinafter "1997 Rule"). The new NAAQS replaced the one-hour, 0.12 ppm standard with an eight-hour, 0.08 ppm standard, now measured as the fourth-highest daily level in a calendar year. *Id.* The new standard thus both changed the measuring scheme and was marginally more stringent, as EPA recognized that an eight-hour level of 0.09 ppm would have "generally represent[ed] the continuation of the present level of protection." *Id.* at 38,858. Alongside its revised standard, EPA also announced an implementation "guidance" indicating its intention to phase out the one-hour standard only after "EPA determines that the area has air quality meeting the 1-hour standard," *id.* at 38,894 (codified at 40 C.F.R. § 50.9(b)), while implementing the eight-hour standard under the generic Subpart 1 of the Act, *id.* at 38,873.

9 On petitions for review, this court held, in relevant part, that under *Chevron*[1] Step 1 EPA could not use the discretion-filled Subpart 1. Congress had expressed its clear intent that the mandatory control scheme it set forth in Subpart 2 was to be used to regulate ozone. *Am. Trucking Ass'ns v. EPA*, 175 F.3d 1027, *amended on reh'g*, 195 F.3d 4 (D.C.Cir.1999). On certiorari, the Supreme Court agreed that Subpart 2 "unquestionably" "provide[s] for classifying nonattainment ozone areas under the revised standard," but disagreed that the case could be resolved exclusively under *Chevron* Step 1. *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 482-86, 121 S.Ct. 903, 149 L.Ed.2d 1 (2001). Instead, the Court recognized that

10 to the extent that the new ozone standard is stricter than the old one, the classification system of Subpart 2 contains a gap, because it fails to classify areas whose ozone levels are greater than the new standard (and thus nonattaining) but less than the approximation of the old standard codified by Table 1.

11 *Id.* at 483, 121 S.Ct. 903 (citations omitted). In addition to this classification gap, the Court also found a measurement gap and a timing gap: the one-hour averages could not well be used to evaluate eight-hour ozone concentrations and the deadlines set forth in Table 1 would "make no sense for areas that are first classified under a

12

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new standard after November 15, 1990." *Id.* at 483-84, 121 S.Ct. 903. The Court therefore indicated that "[t]hese gaps in Subpart 2's scheme prevent us from concluding that Congress clearly intended Subpart 2 to be the exclusive, permanent means of enforcing a revised ozone standard in nonattainment areas." *Id.* at 484, 121 S.Ct. 903. Thus, it "would defer to the EPA's reasonable resolution of that ambiguity" under *Chevron* Step 2. *Id.*

While recognizing the existence of these gaps, the Supreme Court was careful to emphasize their narrow scope. EPA was not "to render Subpart 2's carefully designed restrictions on EPA discretion utterly nugatory," nor could it "construe the statute in a way that completely nullifies textually applicable provisions meant to limit its discretion." *Id.* at 484-85, 121 S.Ct. 903. Because "Subpart 2 was obviously written to govern implementation for some time," EPA's 1997 approach, leaving Subpart 2 "abruptly obsolete," was "astonishing." *Id.* at 485, 121 S.Ct. 903. Thus, while EPA was invited to exercise its discretion as to the relationship between Subparts 1 and 2, the Court instructed that the range of reasonable interpretations was constrained.

13 In 2003, with the eight-hour NAAQS still awaiting implementation by EPA, several environmental groups sued seeking adherence by EPA to its obligation to designate nonattainment areas under section 107(d)(1) of the Act, 42 U.S.C. § 7407 (d)(1). *See* Air Quality Designations and Classifications for the 8-Hour Ozone NAAQS, 69 Fed.Reg. 23,858, 23,860 (Apr. 30, 2004). EPA entered into a consent decree requiring it to issue the designations by April 15, 2004. *Id.*

14 On April 30, 2004, EPA promulgated the implementation rule, 69 Fed.Reg. 23,951, which announced a new approach to ozone regulation. Reversing its 1997 position, EPA announced that the one-hour NAAQS would be withdrawn "in full," one year following the effective date of the eight-hour NAAQS designations. *Id.* at 23,954 (codified at 40 C.F.R. § 50.9(b)). Under the 2004 Rule, Subpart 2 would apply only to areas that were nonattaining under both the eight-hour standard and the now-revoked one-hour standard. *Id.* at 23,958. Subpart 1 would apply to the remaining eight-hour nonattainment areas (i.e., those with eight-hour design values greater than 0.08 ppm but one-hour design values no greater than 0.12 ppm). EPA reasoned that placing more areas under the "more flexible provisions of the CAA" would "provide the States and Tribes with greater discretion in determining the mix of controls needed to expeditiously attain the 8-hour NAAQS." *Id.* As a result, 76 of 122 nonattaining areas would be governed by Subpart 1. *See* Proposed Rule To Implement the 8-Hour Ozone NAAQS, 68 Fed.Reg. 32,802, 32,814 (June 2, 2003) (hereinafter "2003 NOPR").

15 In addition to this interpretation of the classification gap, the 2004 Rule also addressed the measurement and timing gaps. Whereas the 1990 Amendments prescribed classifying areas as of that date and starting the attainment clock on November 15, 1990, under the 2004 Rule, areas would be redesignated under the eight-hour standard as covered by Subpart 1 or one of the five categories of Subpart 2 (Marginal, Moderate, Serious, Severe, or Extreme) according to a regulatory translation of Table 1. *Id.* at 23,998 (codified at 40 C.F.R. § 51.903(a) tbl.1). EPA's translation meant that areas with the same percentage deviation from the one-hour NAAQS and the eight-hour NAAQS would be classified the same. *Id.* at 23,957. The deadlines for attainment set forth in Table 1 were interpreted to restart as of the date of classification under the new standard. *See id.* at 23,966-67. Because air quality had improved since 1990, the net effect of the new approach was that many areas would have a lower classification for eight-hour ozone than they had for one-hour ozone. Recognizing that this could result in areas being subjected to less stringent controls, EPA interpreted the anti-backsliding provision, section 172(e) of the Act,

16

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and reasoned that "if Congress intended areas to remain subject to the same level of control where a NAAQS was relaxed, they also intended that such controls not be weakened where the NAAQS is made more stringent." *Id.* at 23,972. As a result, the 2004 Rule mandates that all "controls" from the one-hour era must remain in place, including controls that a state was already obligated to adopt but as yet had not. *Id.* However, EPA determined that only certain of the programs established by Congress in Subpart 2 constituted applicable "controls"; the others would not need to be retained. So, the 2004 Rule authorized states to remove from their SIPs one-hour New Source Review ("NSR"), section 185 penalty provisions for Severe and Extreme areas, conformity demonstrations, and attainment contingency plans. *Id.* at 23,984-85.

II.

In these consolidated petitions, a host of parties challenge the 2004 Rule and related EPA decisions on rehearing.[2] No petitioner disputes that the eight-hour standard must be implemented; instead, they differ as to how quickly it must be attained and under what constraints. Parties with similar concerns were grouped for briefing purposes, leaving four principal opponents to various aspects of the 2004 Rule: the State petitioners,[3] the Environmental petitioners, the Industry petitioners, and the State of Ohio. A subset of the petitioners also intervened to support different aspects of the 2004 Rule to which other petitioners objected. To summarize the challenges: The State and Environmental petitioners contend that EPA's understanding of the interrelationship between Subpart 1 and Subpart 2 contravenes the Act and led to arbitrary and capricious choices reflected in the 2004 Rule. The State of Ohio contends that EPA erred by establishing an unreasonable timeframe for attainment. One Industry petitioner, the National Petrochemical & Refiners Association ("NPRA"), contends that EPA's translation of the statutory one-hour Table 1, CAA § 181(a) tbl.1, 42 U.S.C. § 7511(a) tbl.1, into a converted regulatory eight-hour Table 1, 40 C.F.R. § 51.903(a) tbl.1, is flawed and thus arbitrary and capricious. Another Industry petitioner, the Chamber of Greater Baton Rouge ("Baton Rouge"), contends that EPA lacks authority to continue to enforce any one-hour requirements against areas with lower eight-hour classifications. The State and Environmental petitioners, conversely, contend that EPA should have retained more of the one-hour control requirements to prevent backsliding, and the Environmental petitioners contend that EPA should not have revoked the one-hour standard at all.

Upon review of these challenges, the court may reverse any action found to be "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." CAA § 307(d)(9), 42 U.S.C. § 7607(d)(9). The court will defer to EPA's statutory interpretations in accordance with the two-step framework of *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 842-43, 104 S.Ct. 2778, 81 L.Ed.2d 694 (1984); *see Bluewater Network v. EPA*, 372 F.3d 404, 410 (D.C.Cir.2004). The court first asks "whether Congress has directly spoken to the precise question at issue." *Chevron*, 467 U.S. at 842, 104 S.Ct. 2778. If so, "that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress." *Id.* at 842-43, 104 S.Ct. 2778. However, if "the statute is silent or ambiguous with respect to the specific issue, the question for the court is whether the agency's answer is based on a permissible construction of the statute." *Id.* at 843, 104 S.Ct. 2778. Upon review of these challenges, for the following reasons, we dismiss Ohio's petition, grant the State petition, grant the Environmental petition in part, and deny the Industry petitions.

III.

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The State of Ohio petitions for review on the ground that the attainment dates for eight-hour ozone are unreasonably soon and favors waiting to impose the eight-hour standard until the one-hour standard has been achieved. The Act provides that an aggrieved party may petition for judicial review in this court as to any "nationally applicable regulations promulgated, or final action taken, by the Administrator under [the Act.]" CAA § 307(b)(1), 42 U.S.C. § 7607(b)(1). However, "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." CAA § 307(d)(7)(B), 42 U.S.C. § 7607(d)(7)(B). As a result, Ohio is barred from seeking relief from the 2004 Rule.

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In its petition for review, Ohio objects to the allegedly unreasonable attainment time-frame adopted by EPA. Ohio's comments during rulemaking, however, express a different view as to attainment deadlines: that "[EPA's] approach would be a reasonable interpretation of Subpart 2." Ohio EPA's Comments on the Proposed 8-Hour Ozone Implementation Plan 2. It is settled law that a party that presents a winning opinion before the agency cannot reverse its position before this court. *See S. Pac. Transp. Co. v. ICC,* 69 F.3d 583, 588 (D.C.Cir.1995).

Citing *Appalachian Power Co. v. EPA,* 135 F.3d 791 (D.C.Cir.1998), Ohio insists that it preserved its challenges in the cover letter to its comments, where it cautioned EPA that "[t]he surest way to develop an implementation plan that holds up to judicial scrutiny would be through an amendment to the Clean Air Act." Letter from Christopher Jones, Director, Ohio EPA, to Marianne L. Horinko, Acting Administrator, EPA (Aug. 1, 2003). Under *Appalachian Power,* commenters must be given some leeway in developing their argument before this court, so long as the comment to the agency was adequate notification of the general substance of the complaint. *Id.* at 817-18. Moreover, for aggrievement that reaches "key assumptions" of an agency, even the failure to object during the comment period is insufficient to bar review. *Id.* at 818. Here, Ohio cannot seriously claim that it put EPA on notice of its objections to the details of the 2004 Rule merely by expressing a general procedural preference in its cover letter. And even if the attainment deadlines constitute a "key assumption," nothing in *Appalachian Power* supersedes the principle that commenters may not reverse course after their preferred approach is adopted by the agency. Therefore, Ohio has forfeited its claims and we must dismiss its petition.

IV.

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The State and Environmental petitioners challenge EPA's resolution of the gap between Subpart 1 and Subpart 2 recognized by the Supreme Court in *Whitman,* 531 U.S. at 483, 121 S.Ct. 903. The State and Environmental petitioners contend that EPA has repeated the errors of the 1997 Rule by promulgating a regulation where 76 of 122 nonattaining areas are projected to be governed by Subpart 1. *See* 2003 NOPR, 68 Fed.Reg. at 32,814. They further contend that the Act does not support any ozone nonattainment areas being regulated exclusively under Subpart 1. Although *Whitman* forecloses the latter contention, we agree that the manner in which the 2004 Rule treats the relationship between Subpart 1 and Subpart 2 fails to adhere to the statutory scheme enacted by Congress in 1990 to address ground-level ozone in nonattainment areas.

A.

The purpose of the Clean Air Act has long been "to promote the public health and welfare and the productive capacity of [the Nation's] population." CAA § 101(b)(1),

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42 U.S.C. § 7401(b)(1). The promulgation of a primary NAAQS specifically addresses this first component, public health. CAA § 109(b), 42 U.S.C. § 7409(b); *see Am. Petroleum Inst. v. Costle,* 665 F.2d 1176, 1181 (D.C.Cir.1981). Because Congress recognized that it must attain this level of air-quality public health without resort to any "`magic' solutions," it adopted the comprehensive regulatory requirements of Subpart 2. H.R. REP. No. 101-490, pt. 1, at 147 (1990), *reprinted in* 2 LEGISLATIVE HISTORY, *supra,* at 3021, 3171.

Had there been no scientific advancements of moment in EPA's view since 1990, the one-hour standard would still be in place. Any area with a one-hour ozone level exceeding 0.121 ppm would be designated nonattainment and all such nonattainment areas would be regulated pursuant to the detailed protocols of Subpart 2. The 1997 Rule changed two aspects of the NAAQS: the measuring stick and the target. Changes in the former provide no basis for the displacement of Congress's well-considered approach for reaching its desired level of public health. EPA acknowledged that the level of public health achieved by 0.121 ppm of one-hour ozone is equivalent to the level of public health achieved by 0.09 ppm of eight-hour ozone. *See Whitman,* 531 U.S. at 483, 121 S.Ct. 903; 1997 Rule, 62 Fed.Reg. at 38,858. Any area failing to achieve the equivalent of Congress's chosen level of public health must be covered by Congress's chosen prophylactic scheme. Therefore, to the extent that the 2004 Rule regulates areas with an eight-hour design value exceeding 0.09 ppm under Subpart 1, EPA has misinterpreted the gap where it is authorized to exercise its discretion and has trespassed into areas where Subpart 2 unquestionably applies.

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The Supreme Court in *Whitman* recognized three gaps in the Act that were evident after the 1997 change in the NAAQS. The first gap was a measurement gap: "Using the old 1-hour averages of ozone levels . . . as Subpart 2 requires would produce at best an inexact estimate of the new 8-hour averages." *Whitman,* 531 U.S. at 483, 121 S.Ct. 903 (citations omitted). The second gap was a classification gap: "to the extent that the new ozone standard is stricter than the old one, the classification system of Subpart 2 contains a gap, because it fails to classify areas whose ozone levels are greater than the new standard (and thus nonattaining) but less than the approximation of the old standard codified by Table 1." *Id.* (citations omitted). The third gap was a timing gap: "Subpart 2's method for calculating attainment dates ... seems to make no sense for areas that are first classified under a new standard after November 15, 1990." *Id.*

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The State and Environmental petitioners read the classification gap quite narrowly. They maintain that this gap merely authorized EPA to adjust Table 1 to incorporate newly nonattaining areas into one of the Subpart 2 categories. Once EPA translated Table 1, its discretion was exhausted. Under this reading, however, all areas would be subject to Subpart 2 as a matter of *Chevron* Step 1. The Supreme Court in *Whitman* indicated otherwise. Although the Court referred to the gap as a "fail[ure] to classify," *Whitman,* 531 U.S. at 483, 121 S.Ct. 903, the Court later said that it could not "conclud[e] that Congress clearly intended Subpart 2 to be the exclusive, permanent means of *enforcing* a revised ozone standard in nonattainment areas." *Id.* at 484, 121 S.Ct. 903 (emphasis added).

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EPA interpreted the classification gap differently, indicating "that there was no gap in the statute for those areas with a 1-hour design value above 0.121 ppm." 2004 Rule, 69 Fed.Reg. at 23,957. This reasoning implies that EPA views the gap as a two-dimensional void bounded by 0.121 ppm of one-hour ozone and 0.08 ppm of eight-hour ozone. But this approach would mean that areas with air less healthful than what Congress thought it had addressed could be freed from Subpart 2. This is not

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the gap that the Supreme Court recognized. The Court characterized the gap as those "areas whose ozone levels are greater than the new standard (and thus nonattaining) but less than *the approximation of the old standard* codified by Table 1." *Whitman,* 531 U.S. at 483, 121 S.Ct. 903 (emphasis added). This statement was preceded by reference to EPA's assertion that the "8-hour standard of 0.09 ppm rather than 0.08 ppm would have `generally represent[ed] the continuation of the [old] level of protection.'" *Id.* (alterations in original) (quoting 1997 Rule, 62 Fed.Reg. at 38,858).

In other words, the gap identified in *Whitman* affords EPA discretion only to the extent that an area is nonattaining but its air quality is not as dangerous as the level addressed by the 1990 Amendments, which now translates to 0.09 ppm on the eight-hour scale. Thus, the gap extends only to the extent that the standard was *strengthened* and not to the extent that the measurement technique merely changed. Recall that when the Supreme Court assessed the 1997 Rule, it thought that the one- and eight-hour standards were to coexist. *Id.* at 478, 121 S.Ct. 903. But the Court nowhere indicated that the still-present threshold for one-hour compliance should be used to partition eight-hour nonattaining areas. To the contrary, considering the statements of the Court in context strengthens the conclusion that the regulation of the eight-hour standard is to be independent of the one-hour standard. Eight-hour nonattainment areas must be subject to Subpart 2 wherever they have air at least as unhealthful as Congress contemplated when enacting the 1990 Amendments. Because *Chevron* Step 1 controls the extent of the gap, we need not address the State and Environmental petitioners' further contentions that EPA's approach absurdly uses one-hour ozone levels—a metric that EPA concedes is no longer relevant—to determine how to fix eight-hour ozone nonattainment, and that this interpretation, by treating areas with similar eight-hour levels differently, is arbitrary and capricious.

B.

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For areas with ozone levels between 0.08 and 0.09 ppm, the 2004 Rule overlaps with the gap recognized in *Whitman*. To this extent, the question under *Chevron* Step 2 is whether EPA's interpretation, while not required to "represent[] the best interpretation of the statute," is reasonable. *Smiley v. Citibank (S.D.), N.A.,* 517 U.S. 735, 744-45, 116 S.Ct. 1730, 135 L.Ed.2d 25 (1996). Obviously, EPA's approach must be "based on a permissible construction *of the statute.*" *Chevron,* 467 U.S. at 843, 104 S.Ct. 2778 (emphasis added).

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In the 2004 Rule, EPA determined that for all areas where it need not impose Subpart 2 requirements, it will not do so. This conforms to "[o]ne of EPA's stated goals ... [,] to provide flexibility to States and Tribes on implementation approaches and control measures within the structure of the CAA." 2004 Rule, 69 Fed.Reg. at 23,958. EPA advances several reasons for its approach: first, "because subpart 2 was developed by Congress 13 years ago and our scientific understanding of the causes of ozone pollution and the transport of ozone and its precursors has significantly advanced," *id.* at 23,960; and second, "[b]ecause control requirements for marginal areas are similar to those for subpart 1 areas, and because most of these areas are projected to attain within 3 years, the distinction in regulatory category may make no practical difference for many of these areas," *id.* at 23,961. *See also* 2003 NOPR, 68 Fed.Reg. at 32,814. Even assuming (without deciding) for purposes of this appeal that the 2004 Rule would be a reasonable approach to reducing air pollution, it is not a reasonable interpretation of Congress's approach in the 1990 Amendments.

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The main thrust of EPA's interpretation is that Subpart 1 is best because it

32 maximizes EPA's ability to tailor a SIP to the situation of that state. But at no point does EPA explain how its interpretation fits with the 1990 Amendments, which Congress purposefully crafted to limit EPA discretion. *See Whitman,* 531 U.S. at 485, 121 S.Ct. 903. Further, to the extent EPA's rationale rests on the claims that technology has advanced since 1990, Congress considered this possibility by providing for periodic review of each NAAQS. *See* CAA § 109(d)(1), 42 U.S.C. § 7409 (d)(1). There are no comparable provisions providing that Subpart 2 requirements may be stripped away if EPA becomes convinced that it may achieve attainment more efficiently. "[I]t is generally presumed that Congress acts intentionally and purposely when it includes particular language in one section of a statute but omits it in another." *City of Chicago v. Envtl. Def. Fund,* 511 U.S. 328, 338, 114 S.Ct. 1588, 128 L.Ed.2d 302 (1994) (internal quotation marks omitted). The interpretation advanced by EPA cannot be squared with Congress's desire to limit EPA discretion by devising a plan that would reach far into the future. *See Whitman,* 531 U.S. at 485, 121 S.Ct. 903. As knowledge about the causes and cures of pollution has increased, Congress has not previously hesitated to step in and modify its approach. That Congress has not provided for an agency override of its methodology is telling.

Similarly, EPA's insistence that certain areas should not be subjected to Subpart 2 because they will soon attain the eight-hour NAAQS is untethered to Congress's approach. Congress considered the possibility of areas being classified nonattaining but missing the target by only a small amount. These are the Marginal areas that are required to introduce far less burdensome ozone controls than areas with more polluted air. *See* CAA § 181, 42 U.S.C. § 7511. Thus, even if "Subpart 1 is preferable to mandating unnecessary Subpart 2 controls," Brief for Respondent at 46, EPA cannot replace Congress's judgment with its own.

We therefore hold that the 2004 Rule violates the Act insofar as it subjects areas with eight-hour ozone in excess of 0.09 ppm to Subpart 1. We further hold that EPA's interpretation of the Act in a manner to maximize its own discretion is unreasonable because the clear intent of Congress in enacting the 1990 Amendments was to the contrary.

V.

33 Industry petitioner NPRA challenges the conversion of the one-hour Table 1, codified at 42 U.S.C. § 7511(a) tbl.1, to its eight-hour regulatory equivalent, 40 C.F.R. § 51.903(a) tbl.1. We first address EPA's contention that NPRA lacks Article III standing to pursue its claims before this court.

A.

34 The doctrine of standing enforces the limitations on the federal judiciary stemming from the Article III case-or-controversy requirement. *See* U.S. CONST. art. III, § 2; *Allen v. Wright,* 468 U.S. 737, 750-51, 104 S.Ct. 3315, 82 L.Ed.2d 556 (1984). A party's standing is a "predicate to any exercise of our jurisdiction." *Fla. Audubon Soc'y v. Bentsen,* 94 F.3d 658, 663 (D.C.Cir.1996) (en banc).

35 As an association, NPRA "has standing to bring suit on behalf of its members when: (a) its members would otherwise have standing to sue in their own right; (b) the interests it seeks to protect are germane to the organization's purpose; and (c) neither the claim asserted nor the relief requested requires the participation of individual members in the lawsuit." *United Food & Commercial Workers Union Local 751 v. Brown Group, Inc.,* 517 U.S. 544, 553, 116 S.Ct. 1529, 134 L.Ed.2d 758 (1996) (quoting *Hunt v. Wash. State Apple Adver. Comm'n,* 432 U.S. 333, 343, 97

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37 S.Ct. 2434, 53 L.Ed.2d 383 (1977)). Only the first element of standing can seriously be challenged here. An individual plaintiff has standing if it can demonstrate injury-in-fact that has been caused by the defendant and that is capable of being redressed by this court's order. *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs. (TOC), Inc.,* 528 U.S. 167, 180-81, 120 S.Ct. 693, 145 L.Ed.2d 610 (2000); *Lujan v. Defenders of Wildlife,* 504 U.S. 555, 560-61, 112 S.Ct. 2130, 119 L.Ed.2d 351 (1992).

EPA contests causation on the ground that because only the states are directly affected by the 2004 Rule, and because EPA has not specifically mandated controls, NPRA is only harmed through the intervening acts of the independent third-party states. *See Nat'l Wrestling Coaches Ass'n v. Dep't of Educ.,* 366 F.3d 930, 938 (D.C.Cir.2004). NPRA responds that it is inevitable that NPRA members will be affected by the 2004 Rule and will be required to install controls either not previously required or at an earlier date than previously anticipated.

In order for NPRA to have standing, there must be a "`substantial probability' that [EPA's] action `created a demonstrable risk, or caused a demonstrable increase in an existing risk, of injury to the particularized interests of'" NPRA. *Nat'l Parks Conservation Ass'n v. Manson,* 414 F.3d 1, 6 (D.C.Cir.2005) (quoting *Fla. Audubon,* 94 F.3d at 669). We have little difficulty concluding that NPRA has met this threshold. It is inconceivable that EPA's comprehensive reworking of an Act that specifically controls the requirements for industrial pollution would fail to affect the requirements of even a single NPRA member. *See Am. Library Ass'n v. FCC,* 406 F.3d 689, 696 (D.C.Cir.2005); *Bethlehem Steel Corp. v. EPA,* 723 F.2d 1303, 1306 (7th Cir.1983); *see also Natural Res. Def. Council, Inc. v. EPA,* 902 F.2d 962, 975 n. 33 (D.C.Cir.1990), *vacated in part on other grounds,* 921 F.2d 326 (D.C.Cir.1991); *Overview, supra,* at 1815.

B.

38 NPRA's petition bridges the classification and timing gaps referenced in *Whitman. See supra* Part IV.A. The court "defer[s] to the EPA's reasonable resolution of the ambiguity." *Whitman,* 531 U.S. at 484, 121 S.Ct. 903. The essence of NPRA's challenge is that while translating Table 1, EPA failed to acknowledge the differences between one-hour and eight-hour ozone. NPRA raises two main contentions: first, that eight-hour ozone is proportionally more difficult to reduce than one-hour ozone; and second, that EPA adopted the new approach aware that some areas would be unable to meet the prescribed guidelines, instead relying upon the states to reclassify themselves voluntarily.

1.

39 To create an updated version of Table 1, EPA considered a number of approaches for determining the proper deadlines and method of classification. With respect to maximum attainment dates, EPA recognized that "a strict application of Table 1 would produce absurd results for most areas" because most of the deadlines had already passed, and "promulgat[ed] a targeted revision of Table 1 to reflect attainment dates consistent with Congressional intent." 2004 Rule, 69 Fed.Reg. at 23,966. Because the original attainment dates were linked to the date on which most areas were designated and classified as a matter of law, EPA proposed to use the same time periods and to start the clock as of the time of designation for eight-hour ozone. 2003 NOPR, 68 Fed.Reg. at 32,808.

The other factor influencing attainment deadlines is the mapping of design values onto area classes. For this purpose, EPA proposed

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to translate the classification thresholds in Table 1 of section 181 from 1-hour values to 8-hour values in the following manner: Determine the percentage by which each classification threshold in Table 1 of section 181 exceeds the 1-hour ozone standard and set the 8-hour threshold value at the same percentage above the 8-hour ozone standard. For example, the threshold separating marginal and moderate areas in Table 1 is 15 percent above the 1-hour standard, so we would set the 8-hour moderate area lower threshold value at 15 percent above the 8-hour standard.

Id. at 32,812. In response to comments, EPA introduced additional alternatives and reopened the comment period. Under the new Alternative A, the range of the one-hour Table 1 was narrowed so that the eight-hour table used

50 percent (instead of 100 percent) of the percentages that the classification thresholds were above the 1-hour NAAQS in our proposed June 2003 translation of Table 1. In other words, since the moderate threshold for the 1-hour NAAQS is 15 percent above the 1-hour NAAQS, we would adjust the moderate threshold for purposes of the 8-hour NAAQS to be 7.5 percent above ... the lowest level in Table 1 for [this alternative].

44 2004 Rule, 69 Fed.Reg. at 23,957[4] ; *see also* Proposed Rule To Implement the 8-Hour Ozone NAAQS, 68 Fed.Reg. 60,054, 60,059 (Oct. 21, 2003). The effect of this approach would be to place more areas in higher classes, giving them more time to attain (while subjecting them to additional mandatory controls).

45 NPRA maintains that EPA should have adopted the fifty-percent approach or some other approach that delayed attainment deadlines it considered to be unreasonable. The basis for this objection is data provided in the rulemaking comments of the American Petroleum Institute ("API"). *See* Comments of the American Petroleum Institute on the Proposed Rule To Implement the 8-Hour Ozone National Ambient Air Quality Standard 7, 13-14. API presented data suggesting that eight-hour ozone levels fell at only half the rate of one-hour ozone levels during the twenty years ending 2001. *Id.* However, EPA did not find these data compelling, explaining that "[p]rograms designed to address the 1-hour ozone NAAQS were not necessarily designed to reduce 8-hour ozone levels at some prescribed rate." Memorandum from Fred Dimmick, Group Leader, Air Quality Trends Analysis Group, on API Comments Regarding Relation Between Ozone 1-Hour and 8-Hour Trends 2 (Feb. 11, 2004). So the historical data (for which EPA also contested the methodology) are not truly predictive of the relative difficulty in reducing one- and eight-hour ozone. Indeed, EPA's own data suggest that the ratio between eight-hour and one-hour ozone is converging toward a constant proportion, eight-tenths. *See id.* at 2, 4 fig.3. This implies that reducing one-hour and eight-hour ozone levels by the same percentage would be equally difficult. In light of these data, NPRA fails to show that EPA was arbitrary or capricious in adopting the percentage-deviation approach.

2.

46 NPRA's second objection is that EPA acknowledged that its classification scheme may result in some areas that will not be able to attain by the deadline prescribed for their category. For these "misclassified" areas, EPA has decided to rely upon the voluntary bump-up provision of section 181(b)(3).[5] *See* 2004 Rule, 69 Fed.Reg. at 23,959-60. NPRA contends that by resorting to section 181(b)(3), EPA is shirking its classification responsibility, leaving these decisions to the states contrary to Congress's intent. Taken to the extreme, section 181(b)(3) could damage Congress's approach. However, Congress understood that the classification system would not be error-proof and merely chose "outside limits intended to provide a reasonable target

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for a large class of nonattainment areas." H.R. REP. No. 101-490, pt. 1, at 229, *reprinted in* 2 LEGISLATIVE HISTORY, *supra*, at 3253.

NPRA maintains that EPA anticipates fifteen areas, including major metropolises, will be unable to attain within the time allowed. However, EPA found that its chosen option "provides sufficient time for most areas." 2004 Rule, 69 Fed.Reg. at 23,959. Moreover, its modeling did not incorporate future technological advances. EPA's "repeated experience over the past three decades is that market forces stimulated by the CAA have repeatedly led to technological advances and learning through experience, making it possible over time to achieve greater emissions reductions at lower costs than originally anticipated." *Id.*

In light of the nature of the classification scheme, the availability of section 181(b)(3) bump-ups, and the prospects for future technological improvements credited by EPA, we deny NPRA's petition.

VI.

49 The final set of challenges concerns what remains of the old one-hour standard. The Environmental petitioners contend that EPA's revocation of the one-hour standard was unlawful and arbitrary. Short of that, they join the State petitioners in contending that the 2004 Rule violates the anti-backsliding provisions of the Act. Industry petitioner Baton Rouge contends that EPA lacks authority to require any anti-backsliding provisions that do not relate to the eight-hour NAAQS.

A.

50 In 1997, EPA determined that, while it was replacing the one-hour NAAQS with an eight-hour NAAQS, it would continue to enforce the one-hour NAAQS until "a determination by the EPA that an area has attained air quality that meets the 1-hour standard." Implementation Plan for Revised Air Quality Standards, 62 Fed.Reg. 38,421, 38,424 (July 18, 1997); *see Whitman*, 531 U.S. at 478, 121 S.Ct. 903; 1997 Rule, 62 Fed.Reg. at 38,873, 38,894-95. In the 2004 Rule, EPA reversed course, opting instead to "revoke the 1-hour standard in full, including the associated designations and classifications, 1 year following the effective date of the designations for the 8-hour NAAQS." 2004 Rule, 69 Fed. Reg. at 23,954. The Environmental petitioners contend that because Congress "codified" the one-hour standard, EPA cannot revoke it. In the alternative, they contend that EPA was arbitrary and capricious in revoking the standard, because maintaining the one-hour standard would also help to reduce eight-hour ozone levels. EPA responds that any challenge to its 1997 Rule is time-barred, and, in any event, its actions are reasonable.

1.

The judicial review provision of the Act provides aggrieved parties sixty days in which to petition for review. CAA § 307(b), 42 U.S.C. § 7607(b). Were the Environmental petitioners challenging the revocation of the one-hour standard, which occurred in the 1997 Rule revising the standard, its petition would be out of time and the court could not entertain it. However, we read their petition to challenge only the revocation of the one-hour standard prior to its attainment, as their reply brief makes clear. This objection is timely. *Cf. Clean Air Implementation Project v. EPA*, 150 F.3d 1200, 1204 (D.C.Cir. 1998).

Because the EPA indicated in the 1997 Rule that it had no intention of withdrawing the one-hour standard before all areas had reached attainment, *see*

53 1997 Rule, 62 Fed.Reg. at 38,873, Environmental petitioners had no reason to lodge their challenge in 1997. The 1997 Rule did not reflect a finding that one-hour ozone was unimportant and that continued regulation was unnecessary. *See id.* at 38,872. As the Environmental petitioners observe, it was only when EPA switched course in the 2004 Rule, opting to revoke the one-hour standard without awaiting attainment, that their challenge became ripe. This is not a case like *Environmental Defense v. EPA,* 467 F.3d 1329 (D.C.Cir.2006), where EPA did not change its 1997 regulation when promulgating a 2004 rule. *Id.* at 1333. Because the Environmental petitioners' challenge is timely, we turn to the merits.

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2.

Section 109(d)(1) of the Act provides that "at five-year intervals . . ., the Administrator shall complete a thorough review of the ... national ambient air quality standards promulgated under this section and shall make such revisions in such ... standards as may be appropriate." 42 U.S.C. § 7409(d)(1). The anti-backsliding provision, section 172(e), provides that in the event "the Administrator relaxes a [primary NAAQS] after November 15, 1990, the Administrator shall ... provide for controls which are not less stringent than the controls applicable to areas designated nonattainment before such relaxation." 42 U.S.C. § 7502(e).

The Environmental petitioners contend that the one-hour standard cannot be withdrawn because Congress "codified" the one-hour standard in Subpart 2. Congress contemplated, however, the possibility that scientific advances would require amending the NAAQS. Section 109(d)(1) establishes as much, and section 172(e) regulates what EPA must do with revoked restrictions. While certain other provisions in Subpart 1 are explicitly rendered inapplicable to ozone when regulated under Subpart 2, *see* CAA § 172(a)(1), (2), 42 U.S.C. § 7502(a)(1), (2), Section 109(d)(1) is not. *See Am. Trucking Ass'ns,* 175 F.3d at 1047. Therefore, EPA retains the authority to revoke the one-hour standard so long as adequate anti-backsliding provisions are introduced. Additionally, EPA was not, as the Environmental petitioners contend, arbitrary and capricious in withdrawing the one-hour requirements, having found in 1997 that the eight-hour standard was "generally even more effective in limiting 1-hour exposures of concern than is the current 1-hour standard." 1997 Rule, 62 Fed.Reg. at 38,863. The only remaining requirements as to the one-hour NAAQS are the anti-backsliding limitations.

B.

55 Baton Rouge takes the opposite position and contends that no remnants of the one-hour rule may be retained, except to the extent that controls are already incorporated into SIPs. These controls, however, could be removed pursuant to section 110(*l*) of the Act once the state demonstrates that their removal will not "interfere with any applicable requirement concerning attainment and reasonable further progress" toward the eight-hour standard. 42 U.S.C. § 7410(*l*).

56 Baton Rouge has suffered from a history of near-misses in ozone attainment. In 1990, the area was classified Serious under Table 1, providing until 1999 to attain. When Baton Rouge missed attainment, by just 0.002 ppm, it was bumped up to Severe status by the terms of the Act. *See* CAA § 181(b)(2), 42 U.S.C. § 7511(b)(2). Baton Rouge had not finished implementing the controls for a Severe area when the eight-hour standard was put into place. Based on its eight-hour design value, Baton Rouge was reclassified under Subpart 2 as Marginal. 40 C.F.R. § 81.319.

57 Baton Rouge objects to the 2004 Rule insofar as it requires the implementation of

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Severe controls not yet implemented that it claims do not constitute "applicable requirements" that must be included in SIPs. 40 C.F.R. § 51.900(f); *see* CAA § 172(c)(7), 42 U.S.C. § 7502(c)(7). It contends that it should be subjected only to the requirements for a Marginal eight-hour area, both because these requirements reflect the improved quality of Baton Rouge's air and because they now constitute the "applicable requirements" under the prevailing NAAQS. It is undisputed, of course, that Baton Rouge would be subject to all of the Severe requirements but for the change in the NAAQS. Baton Rouge's contention is the counterintuitive claim that the strengthening of the NAAQS entitles it to a weaker regulatory regime.

At the center of this dispute is EPA's interpretation of the anti-backsliding provision, section 172(e), 42 U.S.C. § 7502(e). By its terms, Section 172(e) applies only when EPA "relaxes" a primary NAAQS, *id.*, but EPA interpreted it to apply here, reasoning that "if Congress intended areas to remain subject to the same level of control where a NAAQS was relaxed, they also intended that such controls not be weakened where the NAAQS is made more stringent." 2004 Rule, 69 Fed.Reg. at 23,972. Considered as a whole, the Act reflects Congress's intent that air quality should be improved until safe and never allowed to retreat thereafter. Even if EPA set requirements that proved too stringent and unnecessary to protect public health, EPA was forbidden from releasing states from these burdens. *See* CAA § 172(e), 42 U.S.C. § 7502(e). Even areas that attained were not allowed to remove controls. At most, an attaining area was allowed to shift controls from active enforcement to the contingency plan that would be automatically triggered should air quality again deteriorate. CAA § 175A, 42 U.S.C. § 7505a. And EPA was to enforce a high threshold for removing controls from a SIP—no mandatory controls could be removed and nothing could be done that would hinder an area's ability to achieve prescribed annual incremental emissions reductions. CAA § 110(*l*), 42 U.S.C. § 7410(*l*). As a result, Baton Rouge's position that Congress intended to allow the scenario it prefers does not withstand scrutiny.

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Similarly, Baton Rouge's position that it need not implement one-hour Serious requirements that were not a part of its SIP when the NAAQS changed fails. A mandatory control that a state is obligated to implement is "applicable" notwithstanding the state's delay in compliance with the requirement. *See* 2004 Rule, 69 Fed.Reg. at 23,972. The Act placed states onto a one-way street whose only outlet is attainment. That Baton Rouge has found attainment more difficult than it apparently expected does not entitle it to reverse course. EPA's interpretation of section 172(e) is to this extent consistent with Congress's expressed intent and therefore is reasonable.

C.

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After interpreting section 172(e) to apply to the strengthening of the ozone NAAQS, EPA proceeded to limit the scope of its interpretation. Finding ambiguity in the word "controls," EPA determined that one-hour NSR, which it characterized as a growth measure, need not be continued. 2004 Rule, 69 Fed.Reg. at 23,985. The State and Environmental petitioners challenge this reinterpretation, as well as EPA's treatment of one-hour penalties, rate-of-progress milestones, contingency plans, and motor vehicle conformity demonstrations. We conclude that each of these measures is a "control[]" and that withdrawing any of them from a SIP would constitute impermissible backsliding.

1.

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NSR. NSR is a permitting process that restricts major modifications and new

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construction based on an area's air-quality classification. *See New York v. EPA,* 443 F.3d 880, 883 (D.C.Cir.2006). As relevant, NSR requires major facilities to include technology consistent with the lowest achievable emissions rate ("LAER") and to offset any increased emissions with greater reductions elsewhere. *See* CAA § 173, 42 U.S.C. § 7503. As with the rest of the Act, the severity of NSR restrictions increases as the nonattainment classification worsens. Moving up a classification results in a narrower definition of a "major" facility and imposes a greater offset ratio for any increased VOC emissions. *See* CAA § 182, 42 U.S.C. § 7511a. Areas yet to attain the one-hour NAAQS were classified at best Severe prior to the revocation of the standard. Under one-hour NSR, they must achieve LAER for any source exceeding 25 tons per year of VOC emissions and must offset any increase in VOC emissions by a decrease of 1.3 times that amount. CAA § 182(d), 42 U.S.C. § 7511a(d).

EPA decided that one-hour NSR requirements are no longer required under the Act and that areas should be constrained only by the NSR requirements for their eight-hour classification. 2004 Rule, 69 Fed.Reg. at 23,985. This marked a change from its 2003 NOPR, in which EPA indicated that "the major source applicability cut-offs and offset ratios continue to apply to the extent that the area has a higher classification for the 1-hour standard than for the 8-hour standard[, because w]e see no rationale under the CAA . . . why the existing NSR requirements should not remain `applicable requirements.'" 2003 NOPR, 68 Fed.Reg. at 32,821. On reconsideration, EPA affirmed the revocation of one-hour NSR. *See* NSR Reconsideration, 70 Fed.Reg. 39,413.

The result of this change is to subject fewer areas to LAER and to offset requirements that themselves are weakened. EPA maintains that this is proper because NSR is not a "control." Instead, EPA defines controls as "mandatory control measures that can be quantified and relied upon in a modeling demonstration to show how the measure helps an area reach attainment." Brief for Respondent at 95; *see also* Nonattainment Major NSR Implementation Under 8-Hour Ozone NAAQS: Reconsideration, 70 Fed.Reg. 17,018, 17,-021-23 (Apr. 4, 2005). By this reasoning, because NSR does not provide *a priori* quantifiable emissions reductions, it is not a control. This interpretation does not withstand scrutiny. By attempting to redefine what is a "control" circularly as a subset of itself, EPA violates logic, its own past practice, and the Act's plain meaning.

EPA maintains that States do not rely upon NSR to actively reduce their ozone levels and that NSR was not introduced to achieve emissions reductions. But this is beside the point because EPA nowhere claims that if NSR were not present, there would be no effect on ozone levels. Its arbitrary distinction between actively reducing levels and merely limiting growth finds no support in the nature of "control." Past and current practice confirms that NSR is a control. The Act itself provides that the NSR permit program involves "controls" when section 108(h) requires EPA to "make information regarding emission control technology available to the States and to the general public through a central database" and indicates that "[s]uch information shall include all control technology information received pursuant to State plan provisions requiring permits for sources." 42 U.S.C. § 7408(h). EPA has consistently found NSR to be a control. In its No_x SIP Call, 63 Fed.Reg. 57,356, 57,442 tbl.IV-2 (Oct. 27, 1998), EPA included NSR in its list of "controls." In a proposed rule regarding particulate matter, EPA sought to apply two statutory clauses because they "apply to [SIP] provisions and control requirements, which include NSR programs." Proposed Rule To Implement the Fine Particle NAAQS, 70 Fed.Reg. 65,984, 66,035 (Nov. 1, 2005); *see also id.* at 66,037. In a turbine regulation earlier this year, it stated that "emission control programs such as . . . NSR already promote or require

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emission controls that would effectively prevent emissions from increasing." Standards of Performance for Stationary Combustion Turbines, 71 Fed.Reg. 38,482, 38,491 (July 6, 2006). In addition, the court has previously characterized NSR as imposing "control requirements." *New York,* 443 F.3d at 883; *see also Sierra Club v. Costle,* 657 F.2d 298, 338 (D.C.Cir.1981) (quoting Standards of Performance for New Stationary Sources, 45 Fed.Reg. 8210, 8220 (Feb. 6, 1980)). Furthermore, the House Report introducing the permit program lists NSR as a "control" at least twice. *See* H.R. REP. No. 101-490, pt. 1, at 166, 168 fig. 1, *reprinted in* 2 LEGISLATIVE HISTORY, *supra,* at 3190, 3192 fig. 1 ("Modification Offsets").

EPA tries to find ambiguity by interposing section 110(a)(2)(A) against (C) and section 172(c)(1) and (6) against (5). The Sixth Circuit credited this approach in *Greenbaum v. EPA,* 370 F.3d 527 (6th Cir.2004). However, *Greenbaum* involved a different ultimate question, namely, whether NSR is required for *attainment* areas, and required that court to determine the meaning of a different term, "measures." Because the term "measures" was used in the provision providing for redesignation to attainment, the Sixth Circuit found it appropriate to refer to other instances of "measures" elsewhere in the Act and concluded that NSR was not a "measure." *Id.* at 535-38. This has no bearing on whether NSR is a "control." In light of abundant other evidence that NSR is a control, EPA's attempt to conjure up ambiguity by referring to provisions involving a different noun is unavailing.

We therefore conclude that there is no ambiguity as to the meaning of "control" in Section 172(e), the anti-backsliding provision. Something designed to constrain ozone levels is a "control," and this would include NSR. To conclude otherwise would mean that Congress considered its carefully-crafted and well-calibrated graduated restrictions on new and modified sources less important than other provisions. If anything, the Act and its legislative history reflect the opposite position. *See New York,* 443 F.3d at 887 (citing 42 U.S.C. § 7411(a)(4)); S. REP. No. 101-228, at 24-25 (1989), *reprinted* in 5 LEGISLATIVE HISTORY, *supra,* at 8364-65.

2.

67 *Penalties.* The 1990 Amendments took a long-horizon approach to the problem of ozone pollution. Recognizing that some areas would struggle long into the future, the 1990 Amendments extended attainment dates as late as 2005 and 2010. Beyond those deadlines, the 1990 Amendments provided for penalties, CAA § 185(a), 42 U.S.C. § 7511d(a),[6] to encourage areas still yet to attain. Because EPA promulgated the 2004 Rule before the first penalties would have been required in 2005, the provision has never been enforced. EPA uses this convenient timing to argue that the section 185(a) penalties are therefore excluded from the reference in the anti-backsliding provision, section 172(e), to "controls applicable . . . before . . . relaxation." 42 U.S.C. § 7502(e).

68 EPA reasons that the Act "does not mandate that controls be as stringent as those that could not be required to be imposed until a date after the previous NAAQS no longer exists." 2004 Rule Reconsideration, 70 Fed.Reg. at 30,593. This assertion is untenable. By EPA's reading, the standards could be changed every fourteenth year—just prior to the attainment date—and a state could go unpenalized without ever attaining even the original NAAQS referenced in the 1990 Amendments. The Supreme Court in *Whitman* instructed that

69 Subpart 2 was obviously written to govern implementation for some time. . . . A plan reaching so far into the future was not enacted to be abandoned the next time the EPA reviewed the ozone standard—which Congress knew could happen at any

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time, since the technical staff papers had already been completed in late 1989.

531 U.S. at 485, 121 S.Ct. 903.

As Congress set the penalty deadline well into the future, giving states and industry ample notice and sufficient incentives to avoid the penalties, they were "applicable" before they actually were imposed. For a provision to be "applicable" in this context, it need not be currently enforceable. Congress designed section 185(a) to influence state action prior to 2005, and in this sense, it has long been "applicable." If a group of petitioners believed that the penalties were unlawful and would force the implementation of unnecessary changes, they would have had a ripe claim long ago under *Abbott Laboratories v. Gardner,* 387 U.S. 136, 148-49, 153, 87 S.Ct. 1507, 18 L.Ed.2d 681 (1967). *Accord Chamber of Commerce v. Reich,* 57 F.3d 1099, 1101 (D.C.Cir.1995). Because these penalties were designed to constrain ozone pollution, they are controls that section 172(e) requires to be retained. While EPA maintains that it would be impractical to enforce these penalties because EPA will no longer make findings of attainment and conformity assessments as to the one-hour standard, *see* 2004 Rule, 69 Fed.Reg. at 23,985, section 172(e) does not condition its strict distaste for backsliding on EPA's determinations of expediency; EPA must determine its procedures *after* it has identified what findings must be made under the Act. For these reasons, section 185 penalties must be enforced under the one-hour NAAQS.

3.

72 *Milestones.* Rate-of-progress milestones apply to areas categorized Moderate and above and require annual percentage reductions in ozone-precursor emissions. CAA § 182(b)(1), (c)(2)(B), (d), (e), 42 U.S.C. § 7511a(b)(1), (c)(2)(B), (d), (e). Serious areas must develop adequate plans to attain three-percent annual reductions over each three-year period until attainment. CAA § 182(c)(2)(B), 42 U.S.C. § 7511a(c)(2)(B); *see Sierra Club v. EPA,* 356 F.3d 296, 299 (D.C.Cir.2004).

73 The Environmental petitioners sought review of EPA's treatment of these provisions, believing them no longer to apply to one-hour ozone levels under the 2004 Rule. EPA responded that petitioners had misinterpreted the 2004 Rule and that rate-of-progress plans continue in force as "applicable requirements" based on the one-hour standard. Because there is no dispute here, we merely take note of EPA's interpretation of its rule. *See Alaska Prof'l Hunters Ass'n v. FAA,* 177 F.3d 1030, 1033-34 (D.C.Cir.1999).

4.

Contingency Plans. Each SIP must include "specific measures to be undertaken if the area fails to make reasonable further progress, or to attain the national primary ambient air quality standard by the attainment date." CAA § 172(c)(9), 42 U.S.C. § 7502(c)(9); *see* CAA § 182(c)(9), 42 U.S.C. § 7511a(c)(9) (contingency plans for Serious areas); *Sierra Club v. EPA,* 294 F.3d 155, 164 (D.C.Cir.2002). EPA determined that "[w]here contingency measures have not yet been triggered, we believe it is consistent with Congressional intent to allow areas to remove those measures (or to modify the trigger for such measures to reflect the 8-hour standard)." 2004 Rule Reconsideration, 70 Fed.Reg. at 30,599.

EPA can point to no aspect of Congress's approach that suggests that the one-hour ozone levels specifically addressed by statute can be allowed to deteriorate. Even if EPA had determined that ozone was not nearly as damaging as previously believed

76 and that a level of 100 ppm was acceptable, section 172(e) would still require the automatic imposition of contingency measures if an area were to miss the preexisting threshold of 0.12 ppm. This is precisely the type of backsliding contemplated by the Act. As discussed with respect to penalties, EPA's emphasis on whether the controls have been "triggered" is a red herring. To conform to Congressional intent, one-hour contingency plans must remain in place even after transitioning away from the one-hour standard.

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5.

Motor Vehicle Emission Budgets. In enacting the 1990 Amendments, Congress was particularly concerned with pollution arising from automobile emissions. *See* S. REP. No. 101-228, at 85-86, *reprinted in* 5 LEGISLATIVE HISTORY, *supra,* at 8425-26. As a result, it strengthened efforts to ensure that local transportation planning conforms to pollution controls in approved SIPs by adding section 176(c)(2)(A), 42 U.S.C. § 7506(c)(2)(A).[7] *See Envtl. Def. Fund v. EPA,* 167 F.3d 641, 643-44 (D.C.Cir.1999). Conformity, in turn, requires a finding that anticipated emissions will not frustrate a SIP's purpose nor contribute additional violations or delays in any area. CAA § 176(c)(1), 42 U.S.C. § 7506(c)(1). EPA implemented this mandate by establishing motor vehicle emissions budgets not to be exceeded by Metropolitan Planning Organizations. *See* 40 C.F.R. § 93.118.

In the 2004 Rule, EPA determined that "conformity determinations [would] no longer [be] required for the 1-hour NAAQS." 69 Fed.Reg. at 23,985; *see also* Transportation Conformity Rule Amendments for the New 8-Hour Ozone and $PM_{2.5}$ NAAQS, 69 Fed.Reg. 40,004, 40,009 (July 1, 2004) (hereinafter "Transportation Conformity Rule Amendments"). EPA acknowledged that "the majority of commenters that addressed this issue objected to EPA's proposal," 2004 Rule, 69 Fed.Reg. at 23,986, but concluded that the Act "specifically states that conformity applies only in" nonattainment and maintenance areas, *id.* at 23,987.

78 Although section 176 provides a floor above which conformity determinations are required, EPA cannot conclude that conformity determinations are unnecessary without confronting section 172(e). Because one-hour conformity determinations constitute "controls" under section 172(e), they remain "applicable requirements" that must be retained. EPA cannot well respond to commenters' concerns that removing one-hour conformity demonstrations would "allow large increases in motor vehicle emissions" by acknowledging that "requiring conformity for both ozone standards at the same time would be overly burdensome and confusing." Transportation Conformity Rule Amendments, 69 Fed.Reg. at 40,009-10. EPA is required by statute to keep in place measures intended to constrain ozone levels—even the ones that apply to outdated standards—in order to prevent backsliding. This principle encompasses conformity determinations.

VII.

79 Consistent with *Whitman* and the Act, we grant the State petition and the Environmental petition, except with respect to the withdrawal of the one-hour NAAQS; we also deny the Industry petitions and we dismiss the Ohio petition. Accordingly, we vacate the 2004 Rule and remand the matter to EPA.

Notes:

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Chevron U.S.A. Inc. v. Natural Res. Def. Council, Inc., 467 U.S. 837, 842-43, 104 S.Ct. 2778, 81 L.Ed.2d 694 (1984) (employing two-step analysis).

2

After limited reconsideration proceedings also challenged here, EPA reaffirmed the 2004 Rule as to NSR,*see* Nonattainment Major New Source Review Implementation Under 8-Hour NAAQS: Reconsideration, 70 Fed.Reg. 39,413 (July 8, 2005) (hereinafter "NSR Reconsideration"), and made additional findings as to penalties, timing, contingency measures, and attainment demonstrations, *see* Phase 1 Implementation of the 8-Hour Ozone NAAQS: Reconsideration, 70 Fed.Reg. 30,592 (May 26, 2005) (hereinafter "2004 Rule Reconsideration").

3

The State petitioners are Connecticut, Delaware, Maine, Massachusetts, New York, and the District of Columbia

4

Alternative A also utilized a different approach for distinguishing between Subpart 1 and Subpart 2 areas. All areas with eight-hour design values exceeding 0.091 ppm were categorized under Subpart 2.2004 Rule, 69 Fed.Reg. at 23,957;*see supra* Part IV.A.

5

Section 181(b)(3) of the Act provides:

The Administrator shall grant the request of any State to reclassify a nonattainment area in that State in accordance with [Table 1] to a higher classification. The Administrator shall publish a notice in the Federal Register of any such request and of action by the Administrator granting the request.

42 U.S.C. § 7511(b)(3).

6

Section 185(a) of the Act provides:

Each implementation plan revision required [for Severe and Extreme ozone nonattainment areas] shall provide that, if the area to which such plan revision applies has failed to attain the [primary NAAQS] for ozone by the applicable attainment date, each major stationary source of VOCs located in the area shall, except as otherwise provided under subsection (c) of this section, pay a fee to the State as a penalty for such failure . . . .

42 U.S.C. § 7511d(a).

7

Section 176(c)(2)(A) provides that

no transportation plan or transportation improvement program may be adopted by a metropolitan planning organization . . . or be found to be in conformity by a metropolitan planning organization until a final determination has been made that emissions expected from implementation of such plans and programs are consistent with estimates of emissions from motor vehicles and necessary emissions reductions contained in the applicable implementation plan.

42 U.S.C. § 7506(c)(2)(A).

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Attachment 28-2

- Teleconference Record, Construction Emissions/General Conformity, Kevin McGarry (NYSDEC) and Todd Tamura (TtEC), May 23, 2007

- The New York, Northern New Jersey, Long Island Nonattainment Area Commercial Marine Vessel Emissions Inventory, Volume One – Report, Starcrest Consulting Group, LLC, April 2003, pages 13-15

- EPA Region comments on the Northeast Gateway Deepwater Port FEIS, November 22, 2006

CONFIDENTIAL
Date/Time: 5/23/07, 7 AM
Participants: Kevin McGarry (NYSDEC), Todd Tamura
Project: Safe Harbor
Topic: Construction emissions/general conformity

Kevin confirmed that (a) NYSDEC uses EPA's NONROAD model to estimate construction emissions—i.e., they don't add in any emissions from fugitive dust, etc.—and (b) NYSDEC is using the Starcrest inventory for commercial marine vessel emissions, and that therefore any analyses based on that document is consistent with their SIP. (He confirmed that he is the correct contact for all nonroad emissions including commercial marine vessels—Ona Papagiorgio, who Ron Stannard identified as the CMV inventory person, is in the stationary source section.)

(I did not mention the Safe Harbor project name or Tetra Tech EC's name, just said I was a consultant.)

The New York, Northern New Jersey, Long Island Nonattainment Area Commercial Marine Vessel Emissions Inventory

Volume 1 - Report

Prepared for:
The Port Authority of New York & New Jersey
United States Army Corps of Engineers, New York District

April 2003

THE PORT AUTHORITY OF NEW YORK & NEW JERSEY

Prepared by:
Starcrest Consulting Group, LLC

Under Contract to: Hatch Mott MacDonald

SECTION 3 GEOGRAPHICAL DELINEATION

This section discusses the geographical area included in the CMVEI and provides an overview on the systems and subsystems which were established to best estimate emissions within the NYNJLINA.

3.1 Geographical Area Studied

As agreed upon by the Regional Air Team (RAT)[7], the study area includes the counties within the NYNJLINA, which has been designated a severe ozone nonattainment area. The counties included in the study were those counties that have a significant commercial marine vessel presence, as listed in Table 3.1 and presented in Figure 3.1.

Table 3.1: New York and New Jersey Counties Evaluated

New York Counties	New Jersey Counties
Richmond (Staten Island)	Ocean
Kings	Monmouth
Queens	Middlesex
New York	Union
Nassau	Hudson
Bronx	Essex
Suffolk	Bergen
Westchester	
Rockland	
Orange (partial)	

As agreed by the RAT, the study includes emissions out to the three nautical mile demarcation line off the eastern coast of the United States (U.S.). Within the counties listed above there are several distinct areas that have been delineated to focus on their specific marine vessel transit characteristics. These are:

- The New York – New Jersey Harbor System (NYNJHS), which is the Port Boundary (see Figure 3.2) encompassing the predominant CMV activity area within the region.
- The Hudson River System (HRS), which connects the NYNJHS to the Port of Albany (not included within the study area).
- The Outer Long Island System (OLIS), which is predominantly a CMV transit system connecting the NYNJHS with Connecticut ports and other northeastern ports.
- The New Jersey Coast System (NJCS), which is the area within three miles of the coastline, is not transited by OGVs or towboats, and therefore no emissions are associated with the NJCS.

[7] The NYSDEC, NJDEP, EPA R2, PANYNJ, and USACE are the founding members of the RAT. The RAT has expanded and includes other regional entities such as the New York City Department of Transportation.

Figure 3.1: New York and New Jersey Counties Evaluated

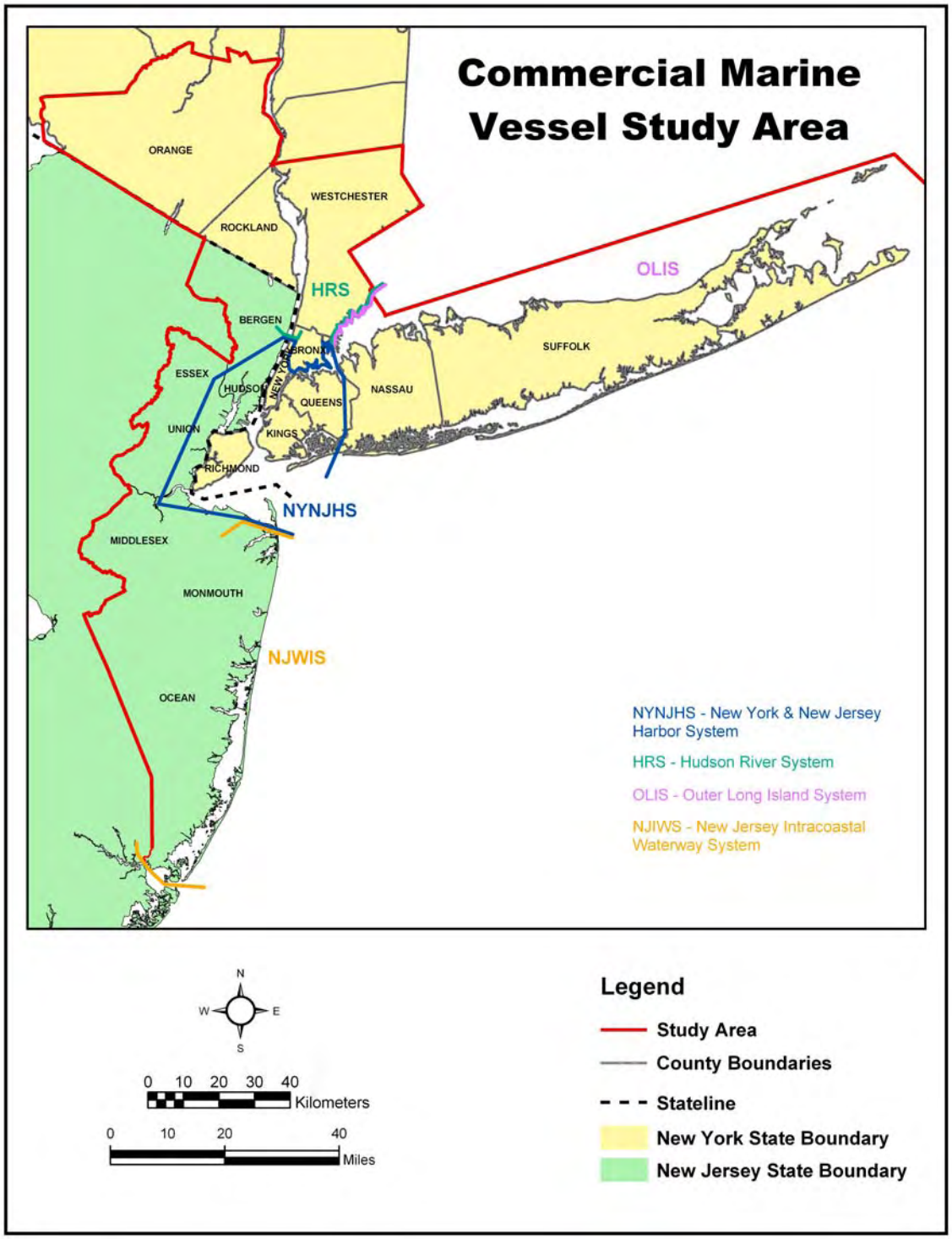

Figure 3.2: New York-New Jersey Harbor System

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 1
1 CONGRESS STREET, SUITE 1100
BOSTON, MASSACHUSETTS 02114-2023

OFFICE OF THE
REGIONAL ADMINISTRATOR

November 22, 2006

Mark A. Prescott
USCG Deepwater Ports Standards Division (G-PSO-5)
U.S. Coast Guard Headquarters
2100 Second Street, SW
Washington, DC 20593-0001

RE: USCG Final Environmental Impact Statement/Environmental Impact Report for the Northeast Gateway Energy Bridge, L.L.C. Liquefied Natural Gas Deepwater Port License Application, DOT Docket Number: USCG-2005-22219, CEQ# 20060441

Dear Mr. Prescott:

In accordance with our responsibilities under the National Environmental Policy Act (NEPA) and Section 309 of the Clean Air Act, the U.S. Environmental Protection Agency (EPA) has reviewed the U. S. Coast Guard's (USCG) Final Environmental Impact Statement (FEIS) for the Northeast Gateway Energy Bridge (Northeast Gateway or NEG), L.L.C. Liquefied Natural Gas Deepwater Port proposed in Massachusetts Bay.

The FEIS details the Northeast Gateway proposal to construct and operate a deepwater port to import liquefied natural gas (LNG) to New England. The proposed port would be located in Massachusetts Bay approximately 13 miles south-southeast of Gloucester, Massachusetts. The deepwater port would consist of two subsea submerged turret loading buoys that would connect to a 16.1 mile long, 24-inch-diameter pipeline that would deliver natural gas to the existing subsea Hubline pipeline which connects to shore. LNG would arrive at the port in Energy Bridge Regasification Vessels and would then be vaporized to natural gas using a shipboard closed-loop process. Following vaporization the natural gas would be transferred from the vessel through the loading buoys to the proposed pipeline. The proposed port would be located in federal waters. Northeast Gateway proposes to begin service by the winter of 2007-2008.

In addition to our environmental review role in this case, EPA is responsible for administering applicable provisions of the Clean Air Act and Clean Water Act. EPA also has cooperated with the Maritime Administration (MARAD) and the USCG in preparing this FEIS to fulfill all of the federal licensing agencies' NEPA compliance responsibilities. EPA has also assisted the USCG and MARAD, the lead agencies, in consultations that federal licensing and permitting agencies are required to conduct with the National Oceanographic and Atmospheric Administration (NOAA) under the Endangered Species Act, National Marine Sanctuaries Act, Marine Mammal Protection

Act, and Magnuson-Stevens Act. EPA is currently reviewing applications filed by Northeast Gateway for permits under the Clean Air Act and Clean Water Act and expects to make draft permits available for public review and comment.

The Northeast Gateway proposal is one of two proposed LNG deepwater ports currently under review by this office, the Neptune LNG deepwater port being the other. As we have indicated in the past, EPA recognizes that New England's air quality has benefited greatly from the increased use of natural gas for electricity generation. EPA also recognizes the need to bring additional natural gas supplies into New England to meet growing energy demands and to maintain the environmental benefits gained over the last ten years. We continue to believe that a well-sited LNG facility, that provides a new supply of natural gas to the region in an environmentally-responsible manner, can make a substantial contribution to maintaining our recent air quality gains.

We appreciate the efforts of the USCG and its consultants to respond to our comments on the Draft EIS and interim FEIS. Based on our review of the FEIS, EPA has no environmental objection to the FEIS. We will continue to work closely with the USCG and the applicant on air and water permits for the project. The enclosure to this letter contains several additional comments that we believe can be addressed in the Record of Decision and the remainder of the licensing process for the project. We continue to encourage the USCG to work closely with NOAA to minimize and mitigate any unavoidable impacts to marine organisms during the construction and operation of the Northeast Gateway port.

Thank you for the opportunity to offer comments on the FEIS for the Northeast Gateway project. Please feel free to contact Timothy Timmermann of the Office of Environmental Review at 617-918-1025 if you have any questions about these comments.

Sincerely,

Robert W. Varney
Regional Administrator

Enclosure

Additional Comments on the Northeast Gateway Deepwater Port FEIS

Generally, the FEIS addresses air and water quality impacts and compliance with the Clean Air Act (CAA) and Clean Water Act (CWA) consistent with EPA's prior comments. EPA does have clarifying comments to offer on the subject of the conformity determination and miscellaneous issues under the CAA.

Conformity under the CAA

Section 176(c) of the CAA prohibits federal entities from taking actions in nonattainment or maintenance areas which do not conform to the applicable implementation plan for the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS). A conformity determination is required in the case of the Northeast Gateway Port because the Deepwater Port Act (DPA) provides that the port is generally subject to the law applicable in the nearest adjacent coastal state. The project emissions of concern are those occurring onshore in the 8-hour ozone nonattainment area, emissions in Massachusetts' State territorial waters (adjacent to the designated nonattainment area), and emissions within the safety area (500 meters around the loading buoys). A general conformity determination is required "for each pollutant where the total of direct and indirect emissions in a nonattainment or maintenance area caused by a Federal action would equal or exceed" specified thresholds. 40 CFR § 93.153(b). Table 4-40, "Total NOx and VOC Emissions Subject to Conformity" on page 4-154 of the FEIS, indicates that project emissions in calendar year 2007 will exceed the applicability thresholds for both NOx (100 tons per year threshold for a moderate ozone nonattainment area in an ozone transport region) and VOC (50 tons per year threshold for a moderate ozone nonattainment area in an ozone transport region). The calendar year 2007 project emissions subject to general conformity are currently calculated as 268 tons of NOx and 50.2 tons of VOC.

EPA is pleased that the USCG and MARAD, prior to issuance of a license under DPA, will issue a draft general conformity determination for Agency and public review, followed by a final general conformity determination. EPA understands that USGC and MARAD intend to demonstrate conformity by requiring the applicant to fully offset calendar year 2007 NOx and VOC emissions (268 tons and 50.2 tons, respectfully) through the purchase of discrete emission reduction credits (ERCs) and/or New Source Review (NSR) offsets (rate-based ERC's) equivalent in time, location and quantity to the emissions from the project in 2007. Operational emissions in calendar year 2008 and later are projected at 59 tons per year of NOx and 18 tons per year of VOC, which are both below the conformity thresholds.

In regard to the General Conformity determination using offsets, the regulations require that these offsets are enforceable at both the state and federal levels. See, 40 C.F.R. 93.152 and 93.158(a)(2). The DPA license can be used to enforce the offset commitments on which the general conformity determination will rely. EPA recommends that MARAD include any necessary conditions of the conformity determination in the Record of Decision (ROD) and include these conditions in the

license, consistent with the written commitments the applicant has provided to support the conformity determination. EPA looks forward to continuing its assistance to USCG in its preparation of its draft General Conformity Determination document.

Section 176(c) of the CAA requires EPA to evaluate independently the applicability of general conformity in connection with our issuance of a CAA Preconstruction Permit and a CWA National Pollution Discharge Elimination System (NPDES) Permit for the Northeast Gateway Port Facility. EPA plans to join USCG and MARAD in circulation of the draft conformity determination, and make our own conformity finding based on the conformity documents and commitments developed by USCG and MARAD. Other Cooperating Federal Agencies including the Federal Energy Regulatory Commission (FERC) and the U.S. Army Corps of Engineers (ACOE) may also need to make independent general conformity determinations. EPA recommends that USCG and MARAD facilitate the conformity process by including all these cooperating agencies in the USCG and MARAD conformity determination process.

Port Access for Compliance Inspections

As EPA moves forward with its air permitting responsibilities for NEG, the Agency will need access to the port vessels to conduct compliance inspections in order to confirm compliance with air emission limits. Preliminary conversations with the USCG in Boston have indicated that the USCG will assist EPA with such access, including opportunities for transport to and from the port such that EPA compliance inspections could be conducted concurrent with USCG activities. EPA commits to working with the USCG to coordinate any EPA inspection trips to the vessels while at port with USCG inspections of the port. In addition, EPA recommends that the ROD and the resulting DPA license specifically provide that the port operator grant access to EPA inspectors who present Agency credentials to allow for inspections on and in the vessels to determine compliance with EPA-issued environmental permits. To that end, we are providing the following draft language which parallels the accessibility language we expect to include in EPA-issued air permits. EPA recommends that this language be included in the ROD and the DPA license.

> The [permittee] shall allow all authorized representatives of the Administrator of the U.S. Environmental Protection Agency, upon presentation of credentials, to enter upon or through any premises of [the permittee], including vessels and other facilities and areas where records required under this permit are kept. The [permittee] shall allow such authorized representatives, at reasonable times, to access and copy any records that must be kept under this permit, to inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit, and to sample or monitor substances or parameters for the purpose of assuring compliance with this permit.

Specific Comments

Page ES-24: It appears that the project will now include the placement of acoustic detection buoys during calendar year 2007. The emissions from the placement of these buoys should be accounted for as indirect emissions in the conformity determination for 2007.

Page ES-31, paragraphs 12 and 13; Page 4-155 under FERC staff recommends; Page 4-162 paragraph 12; and Page 4-163 paragraph 13: EPA notes that the correct citation to the applicable conformity regulations is 40 CFR part 93. Part 51 presents the minimum requirements for a state's conformity program, whereas part 93 contains the federal program that applies in the absence of an approved state program. Here the agencies are addressing the federal program under part 93.

Page ES-38, Second paragraph under Air Quality, ". . . offsets are required for NOx and VOC construction emissions;" and Page 4-155, end of first paragraph: EPA notes that offsets are required for both operational *and* construction emissions that exceed thresholds in calendar year 2007.

Page 1-20, under General Conformity: As discussed in our general comments above, the basis for applying the General Conformity program to this project is that the Deepwater Port Act generally makes the law of the nearest adjacent coastal state applicable to the port. Here, the port, including any portions within state waters and the exclusion zone in federal waters, is included in the conformity program applicable throughout Massachusetts. While the discussion in the FEIS concerning the Ozone Transport Region and Massachusetts Department of Environmental Protection's (MDEP) inventory supporting its ozone attainment demonstration is a useful explanation for the environmental importance of the conformity demonstration, it is EPA's view that these considerations are not the basis for requiring the demonstration.

Page 4-144, Mixing height: EPA continues to recommend that the 24-hour impacts modeling conducted using a mixing height of 500 meters should include model runs with mixing heights limited to 300 meters and 100 meters, because lower mixing heights may prevail and affect pollutant concentrations near the port. Rather than add these additional mixing height runs, the FEIS discusses adding receptors at 100 and 300 meters from the port. This presentation of ambient air impacts appears to be sufficient for the purposes of satisfying the more general requirement under NEPA to explain the project's environmental impacts. But the applicant should be sure to address the mixing height issue, consistent with EPA modeling guidance, in the modeling supporting its application to EPA for air permits under the CAA.

Page 4-145, 4-146 Mobile Sources: This discussion suggests that only vessel navigation emissions and the other listed "minor" emission sources are subject to a general conformity analysis. The discussion appears to assume that operational emissions addressed by the minor new source review permit will not have to be included in the general conformity determination. Stationary emissions from the tankers while moored also need to be evaluated in the conformity process. Stationary source emissions are

exempt from conformity review only if subject to a *major* NSR/Prevention of Significant Deterioration (PSD) permit.

Page 4-152: The FEIS states that "the addition of a new heater at Weymouth Meter Station would not cause the existing station source to exceed any major source NSR/PSD thresholds.... The new heater at the Weymouth station would require a minor source permit from MDEP." EPA agrees that the new heater will have to address applicable air permitting requirements administered on-shore by MDEP. The first part of this discussion, however, suggests that the Weymouth heater is part of the "deepwater port." The port does not extend on-shore under the DPA, and EPA does not believe that emissions from the Weymouth Station would be counted as part of the port's emissions for CAA permitting purposes.

Page 4-154: Table 4-40 correctly shows construction and operation emissions in 2007 exceed the applicable general conformity thresholds (2007 NOx emissions of 268 (267.69) tpy and 2007 VOC emissions of 50.2 (50.16) tpy). EPA wishes to clarify the discussion preceding this table explaining why a conformity determination for carbon monoxide (CO) is not necessary. A CO analysis is not necessary because of the localized impacts of CO emissions in the on-shore areas designated as maintenance areas for CO and MDEP's determination that CO need not be evaluated at the project location. The fact that the project area is at sea does not necessarily exempt it from conformity requirements for CO because the DPA makes the designation of the nearest adjacent coastal state potentially applicable. But in this case, MDEP has concluded that the designation of the relatively isolated CO maintenance areas does not need to be applied through the DPA to the port. EPA also notes that the conformity analysis should also include any indirect emissions caused by the placement of the acoustic detection buoys during 2007.

Page 6-38, lines 42-44: EPA wishes to clarify that determining this project's emissions are consistent with regional air quality requirements depends on a finding of conformity.

Page 6-39, lines 32 through 48 continuing on page 6-40: EPA wishes to clarify that USCG submitted to EPA a *preliminary* draft General Conformity determination for comment, as well as our understanding that the USCG will issue that draft determination for public comment in which EPA expects to join and that the final general conformity determination will be made before issuance of the DPA license.

USCG Comment #29:

Construction emissions exceed 25 tpy of NOx in 2009, 2010, 2011, and 2012 within what is described as state territorial boundaries. With construction of the Island, there are exceedances in 2013 and 2014. Total emissions from 2009 through 2014 for construction are estimated as 222, 531, 469, 324, 172, and 115 tpy, respectively. The operation emissions are 45 tpy in what is termed territorial waters and 204 tpy in the safety zone, both of which exceed the threshold. The application needs to make a clear demonstration that these are included in the New York State Implementation Plan (SIP). In addition, in the event that general conformity is triggered in NJ and/or PA as a result of emissions from assembly of concrete caissons in and transport from Philadelphia, the same demonstration needs to be made with respect to the NJ and PA SIPs.

For the SIP, the discussion of General Conformity makes comparisons to the NYMA projections. While the construction emissions on a daily basis are less than the inventory provided, it will require further review and more documentation on ASIG's part to determine if the project is in the SIP; for example, looking at all sectors of the inventory on an individual basis. For Safe Harbor to be assumed in the SIP, emissions from the Commercial Marine Vessels (CMV) need to be compared to the SIP CMV inventory and from the county where the emissions will originate.

Response:

Response to this data request will be provided on or before January 31, 2009.

USCG Comment #30:

Volume 5, 2.1: The given oxygen content input of 0.0 on p. A-1 is incorrect. 10% ethanol, which is average for most of New York, equates to about 3.5% oxygen by weight. Please revise the analysis as necessary to correct this.

Response:

There are very few pieces of equipment that are using gasoline, and therefore any corrections in emissions associated with a 3.5% oxygen content have a negligible impact.

The only gasoline-fueled nonroad equipment being proposed for use are the 4-stroke 50 hp pieces of equipment used during pipeline construction in 2012. EPA's NONROAD model predicts that emissions of VOC and CO are lower when oxygen is present in the fuel than when it is not, and therefore the current analysis (assuming 0% oxygen in nonroad gasoline) is conservative with respect to those pollutants. With respect to emissions of NO_x, total emissions from all of the gasoline-fueled equipment (assuming 0% oxygen in nonroad gasoline) are 0.7 tons. EPA predicts that the use of 10% ethanol/90% gasoline instead of 100% gasoline increases NO_x emissions in 4-stroke nonroad equipment by 40% (EPA 2005); if this correction were applied to all of the gasoline-powered nonroad equipment, this would increase the 2012 emissions by just 0.3 tons and have no impact on the results of the analysis.

Emissions from nonroad gasoline-fueled vehicles are even lower than from the nonroad gasoline-fueled equipment, and for these vehicles EPA has identified oxygen content as having a minor (< 5%) impact on all criteria pollutant emissions (EPA 2002). Pertinent portions of supporting documents are included in Attachment 30-1.

References:

EPA (U.S. Environmental Protection Agency). 2002. Sensitivity Analysis of MOBILE6.0, EPA420-R-02-035. Available at http://www.epa.gov/otaq/models/mobile6/r02035.pdf.

EPA. 2005. Exhaust Emission Effects of Fuel Sulfur and Oxygen on Gasoline Nonroad Engines, EPA420-R-05-016. Available at http://www.epa.gov/otaq/models/nonrdmdl/nonrdmdl2005/420r05016.pdf.

Attachment 30-1

- EPA Exhaust Emission Effects of Fuel Sulfur and Oxygen on Gasoline Nonroad Engines (NR-003c), EPA420-R-05-016, December 2005, page 5.

- EPA Sensitivity Analysis of MOBILE6.0, EPA420-R-02-035, December 2002, pages iii, iv, 45, 48-55.

EPA420-R-05-016
December 2005

Exhaust Emission Effects of Fuel Sulfur and Oxygen on Gasoline Nonroad Engines

NR-003c

Assessment and Standards Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

NOTICE

This technical report does not necessarily represent final EPA decisions or positions. It is intended to present technical analysis of issues using data that are currently available. The purpose in the release of such reports is to facilitate the exchange of technical information and to inform the public of technical developments which may form the basis for a final EPA decision, position, or regulatory action.

Results

Four Stroke Engines

The oxygen level for the 10 engines in the Gabele study was 2.3 and for the three engines in the Lindhjem and Charmley study was 2.0 weight percent. The average oxygen level for the 13 engines is then considered to be 2.2 weight percent by averaging the oxygen content for all of the engines.

This study calculates the effect by weighting the emission rates (g/kW-hr) by the power level of the engines shown in Table 1 to calculate an average emission rate for the engines tested on base and oxygenated fuels. The NONROAD model assumes that any given engine operates at a constant fraction of available power; therefore, to consistently reflect the overall effect on emissions, each engine in this study is assumed to also operate at a constant fraction of available power.

The effect of adding 2.2% oxygen to the fuel is calculated to reduce HC by 9.8%, increase NOx by 25.2%, and reduce carbon monoxide by 13.6%. The effect per percent of fuel oxygen is then estimated to be -4.5% for HC, +11.5% for NOx, and -6.2% for CO.

Two Stroke Engines

The percent change for the 2.7 and 3.4 weight percent oxygen is shown in Table 4. The overall effect of oxygen on two stroke gasoline engines per percent of fuel oxygen is estimated to be -0.6% for HC, +18.6% for NOx, and -6.5% for CO.

Table 4: The Effect of Fuel Oxygen on the Two Stroke Engine's Exhaust Emissions

Fuel Used	**HC (%/%Oxygen)**	**NOx (%/%Oxygen)**	**CO (%/%Oxygen)**
2.7% Oxygen	-0.4	18.4	-0.4
3.4% Oxygen	-0.8	18.8	-12.5

EPA420-R-02-035
December 2002

Sensitivity Analysis of MOBILE6.0

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TABLE OF CONTENTS

LIST OF FIGURES v

LIST OF TABLES vii

Section

INTRODUCTION 1

METHODS 2

RESULTS. 4

A. PARAMETERS WITH MAJOR EFFECTS ON EMISSIONS (GREATER THAN 20% CHANGES) 5

A.1 HC Emissions
- Registration Distribution Command
- Average Speed Command
- Min/Max Temperature Command
- Speed VMT command
- Fuel RVP (Reid Vapor Pressure)

A.2 CO Emissions
- Min/Max Temperature
- Fuel RVP (Reid Vapor Pressure)
- Registration Distribution command
- Average Speed Command

A.3 NOx Emissions
- Registration Distribution command
- Average Speed Command
- Min/Max Temperature Command

A.4 Major Parameter Summary

B. PARAMETERS WITH INTERMEDIATE EFFECTS ON EMISSIONS (5% TO 20%) 27

B.1 HC Emissions
- Altitude
- Speed VMT Command
- Starts per Day

B.2 CO Emissions
- Air Conditioning
- Altitude
- Mileage Accumulation

Vehicle Starts Per Day

B.3 NOx EMISSIONS
Absolute Humidity
Air Conditioning
Altitude
Mileage Accumulation

C. PARAMETERS WITH MINOR EFFECTS ON EMISSIONS
(LESS THAN 5%) 45

CONCLUSIONS 46

APPENDIX 47

REFERENCES 56

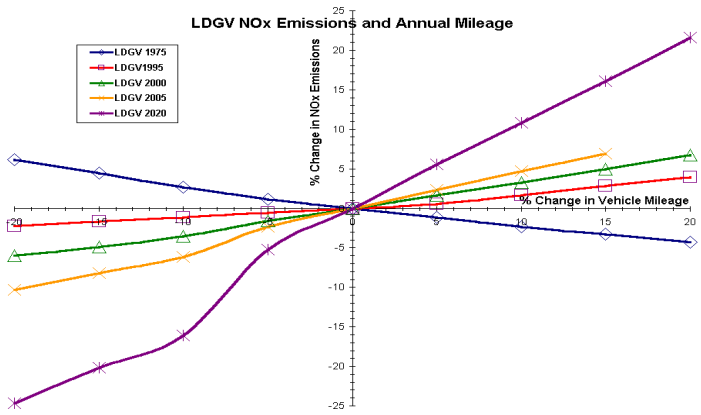

Figure 70. Percent change in LDGV NOx emissions as the default mileage is changed. Figure 53 illustrates how the mileage changed from the MOBILE6 LDGV default mileage.

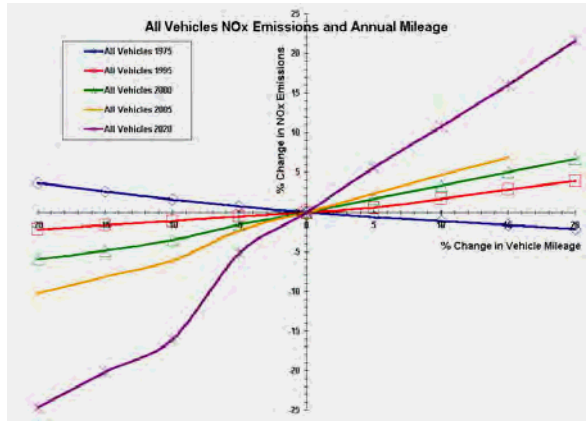

Figure 71. Percent change in All Vehicle NOx emissions as the default mileage is changed for All Vehicle types. See Figure 53 for an illustration of how the mileage were varied relative to the MOBILE6 default values.

C. PARAMETERS WITH MINOR EFFECTS ON EMISSIONS (LESS THAN 5%)

The third and last category of MOBILE6 parameters which have a "minor" (i.e., less than 5%) effect on emissions are listed in Table 3 below. A complete list of the MOBILE6 commands and a description of how the inputs were changed is listed in the Appendix, Table A.2. Because of the relatively small emissions effects the general trends are listed in the table but are not graphically illustrated.

Table 3. List of low level MOBILE6 commands or parameters

HC Emissions :	CO Emissions :	NOx Emissions :
Absolute Humidity	Absolute Humidity	Facility VMT
Air Conditioning	Facility VMT	Fuel Program/Sulfur Content*
Facility VMT	Fuel Program/Sulfur Content*	Fuel RVP
Fuel Program/Sulfur Content*	Hourly Temperature	Hourly Temperature
Hourly Temperature	Oxygenated Fuels	Oxygenated Fuels
Mileage Accumulation	Sulfur Content*	Sulfur Content*
Oxygenated Fuels	Start Distribution	Start Distribution
Sulfur Content*	Temperature Cycles	Temperature Cycles
Start Distribution	Temperature and Humidity	Temperature and Humidity
Temperature Cycles		
Temperature and Humidity		

* In MOBILE6 sulfur content of fuel can be changed in two different calendar year ranges, (1) calendar years less than or equal to 1999 and (2) calendar years greater than 1999. The Fuel Program/Sulfur Content command is used for post 1999 calendar years and the Sulfur Content is used for calendar years1999 and earlier. Sulfur content deteriorates the catalyst. Its effects on hydrocarbon, carbon monoxide, and nitrogen oxide emissions are small. However, it enables the production of sulfur oxides and particulate matter which is not within the scope of this report.

Table A.1. Summary of the LDGV results. (Continued)

COMMAND	Change in Input		Change in Hydrocarbon emissions	Change in CO emissions	Change in Oxides of Nitrogen emissions
Fuel Reid Vapor Pressure(RVP) (The RVP was increased from 6.5lb/in^2 to 11.5lb/in^2 for a number of calendar years between 1975 and 2050 with minimum and maximum temperatures 72°F and 92°F, respectively. Percent differences were determined relative to 7.5lb/in^2)	min.	6.5lb/in^2	approx. -5% (1975-2025)	0% (1975-2025)	approx. 0% (1975-2025)
	max.	11.5lb/in^2	70%(2025) to 40%(1975)	107%(2025) to 2%(1975)	5%(2025) to 0%(1985)
Mileage Accumulation(increase and decrease mileage accumulation relative to the MOBILE6 defaults)	min.	20% decrease	(NMHC) 3%(1980) 5%(2005) 1%(2015) -2%(2020)	-2.5%(1985) to -11%(2020)	0%(1990) to -24%(2020)
	max.	20% increase	(NMHC) 1%(1990) -2%(2000) -3%(2005) 2%(2020)	1%(1980) to 9%(2020)	1%(1990) to 22%(2020)
Oxygenated Fuels (ether concentration from 1% to 2.7%; market share variations from 5% to 50%)	min.	5% mkt, 1%ether, 0% alcohol	(NMHC) 0%(2005&2020)	Approximately 0% (all years)	0%
	max.	50% mkt, 0%ether, 2.7% alcohol	(NMHC) -2% (2000) to -2%(2020)	-5%(2000) to -3%(2020)	0%
Oxygenated Fuels (alcohol concentration from 0.7% to 3.5%; market share variations from 5% to 50%)	min.	50% mkt, 0%ether, 0.7% alcohol	(NMHC) 1% (2000) to 2%(2020)	0.3%(2000) to 2%(2020)	0%
	max.	50% mkt, 0%ether, 3.5% alcohol	(NMHC) Approximately 0% (all years)	-5%(2000) to -2.5%(2020)	0%
Registration Distribution(decrease newer vehicle fractions and increase older vehicle fractions)	min.	5% age shift	(NMHC) 4%(1985) to 25%(2015)	2%(1980) to 16%(2000)	0%(1985) to 14%(2020)
	max.	20% age shift	(NMHC) 12%(1975) to 80%(2015)	7%(1975) 52%(1995) 24%(2020)	-1%(1980) to 50%(2020)
Speed VMT (Arterial; -3% - null low speed vehicle fractions 9% - equal vehicle fractions for all speeds 14% - increase low speed vehicle fraction by 10% 21% - increase low speed vehicle fraction by 20% 29% - increase low speed vehicle fraction by 30%)	min.	-3% (free-flow/ all day non-rush hour speeds)	(NMHC) -3%(all years)	3% (all years)	-1% to 0% (all years)
	max.	29%(congested traffic flow,i.e., 30% more vehicles at the lower speeds)	(NMHC) 32%(1985) to 44%(2050)	-2%(2005) to +3%(1975)	5%(1975) to 8%(2050)
Speed VMT (Freeway; reduce fraction of vehicles from high speeds to lower speeds)	min.	-50% (equal distribution of speeds)	(NMHC) +13%(1975) to 5%(2050)	3%(1975) to -2%(2005)	-1.1%(2050) to -0.5%(1985)
	max.	10%(most vehicles at the higher speeds)	(NMHC)- 3.5%(1975) to -1%(2010)	< 0% and >-2%	+1.6%(1985) to 2%(2050)
Starts Per Day(change the number of starts per day from -50% to +50% in increments of 10% for each vehicle type)	min.	-50%	(NMHC) -17%(2025) to -12%(1975)	-15%(1975) to -11%(2025)	-13%(1975) to -7%(2025)
	max.	50%	(NMHC) 17%(2025) to 12%(1975)	11%(2025) to 15%(1975)	13%(1975) to 7%(2025)

Table A.1. Summary of the LDGV results. (Continued)

COMMAND	Change in Input		Change in Hydrocarbon emissions	Change in CO emissions	Change in Oxides of Nitrogen emissions
Start Distribution	compare emissions with default hourly start fractions to a constant fraction of starts for each hour of the day		(NMHC) 4.5%(1975) to 0.4%(2025)	3%(1975) to 0%(2025)	3%(1975) to 1%(2025)
Sulfur Content (calendar years 1999 and earlier)	min. (300ppm)	0%	(NMHC) 0% (1975) to -0.5%(1999)	0%(1975) to -1%(1999)	0%(1975) to -1%(1999)
	max. (30ppm)	-90%	(NMHC) 0% (1975) to -3.5% (1999)	0%(1975) to -1%(1999)	0%(1975) to -7%(1999)
Temperature, Average Daily (standard temperature cycle and vary average daily temperature 12 F to 107 F)	min.	12 F	(NMHC) 10%(2025) 37%(1995) -13%(1975)	-6%(1975) to 216%(2025)	49%(1975) to 19%(2025)
	max.	107 F	(NMHC) 0%(2025) 24%(1995) -34%(1975)	63%(1975) to 2%(2025)	-19%(1975) to 15%(2025)
Temperature Cycles (keep average daily temperature a constant and vary the standard temperature cycle)	min.	constant temperature (-100%)	(NMHC) -3%(1975,102 F) -2%(1975,42 F) 14%(2025,102 F) -1%(2025,42 F) -8%(2005,82 F)	-11%(1975,102 F) -2%(1975,42 F) -0.5%(2025, 102 F) 5%(2025,42 F) 5%(2005,42 F)	5%(1975,102 F) 1%(1975,42 F) -1.4%(2025,102 F) 1%(2025,42 F) -8%(2025,75 F)
	max.	34 F temperature range (+42%)	(NMHC) 3%(1975,102 F) 2%(1975,42 F) 3%(2025,102 F) 2%(2025,42 F) 6%(2005,82 F)	4%(1975,102 F) 1%(1975,42 F) -0.3%(2025, 102 F) -2%(2025,42 F) -2%(2005,42 F)	-1%(1975,102 F) -1%(1975,42 F) -1%(2025,102 F) -1%(2025,42 F) 8%(2025,75 F)
Temperature, Hourly (hourly temperatures using temperature cycle variations: The percent differences here are for a given hour of the day and model year. They are not results which have been averaged over an entire day. The daily averages tend to lessen the effects.)	min.	constant temperature (-100%)	(NMHC) 12% to -13% (102 F)	-35%((102 F) to 27%(92 F)	-24%(102 F) to 11%(92 F)
	max.	34 F temperature range (+42%)	(NMHC) -5%(102 F) to 3%(72 F)	-11%(92 F) to 7%(72 F)	-5%(92 F) to 4%(72 F)
Temperature, Average Daily and Humidity [For each of a set of daily average temperatures (42, 72, 82, 92, 102, and 107 F) with a 24 F temperature range (the difference between the minimum and maximum temperatures is 24 F) variations of absolute humidity are made. Emission results are determined and compared for each of these average daily temperatures with the absolute humidity set to 53.7, 75, 98.5, 107, and 149.5 grains/lb. for a range of calendar years.]	min.	-28% (54grains/lb)	(NMHC) –1% to 0% (all temperatures and all years)	–2% to 0% (all temperatures and all years)	6%(2025) 7%(2005) 7%(2000) 7%(1975)
	max.	100% (150grains/lb)	(NMHC) 0% to 1% (all temperatures and all years)	0% to 6% (all temperatures and all years)	-14%(2025) -15%(2005) -15%(2000) -16%(1975)

Table A.2. All Vehicle Summary

COMMAND	Change in Input		Change in Hydrocarbon emissions	Change in CO emissions	Change in Oxides of Nitrogen emissions
Absolute Humidity [Use high and low humidity values from August morning and afternoon average relative humidity values from Atlanta and Tucson (National Weather Service data).]	min.	-28% (54grains/lb)	(NMHC) approx. 0%	-1%	5%(1975) 3%(2005)
	max.	100% (149grains/lb)	(NMHC) approx. 0%	3%(1975) 4%(2000) 1%(2025)	-11%(1975) -7%(2005) -11%(2025)
Air Conditioning	Differences Due to MOBILE6 Air Conditioning Correction		(NMHC) 1%(1975) 1%(2005) 0%(2050)	11%(1975) 13%(2005) 4%(2050)	3%(1975) 4%(2005) 8%(2050)
Altitude	Emission Differences Between High Altitude and Low Altitude		(NMHC) 26%(1975) 10%(1995) 7%(2005)	41%(1975) 17%(1995) 10%(2005)	-25%(1975) -3%(1995) -1%(2005)
Average Speed (Arterial roadways)	min.	10mph	(VOC) 69%(2000) 75%(2025)	43%(1975) 26%(2000) 32%(2025)	22%(1975) 20%(2000) 32%(2025)
		35mph	-11%	-11%	-5%(1975) -12%(2000) -8%(2025)
	max.	65mph	(VOC) -28%(1975) -24%(2025)	0%(1975) 17%(2000) 15%(2025)	13%(1975) 23%(2000) 17%(2025)
Average Speed (Area Wide roadways)	min.	10mph	(VOC) 72%	40%(1975) 23%(2000) 28%(2025)	17%(1975) 24%(2025)
	max.	35mph	(VOC) -10%	-4%(1975) 0%(2005) 0%(2025)	-2%
Average Speed (Freeways)	min.	10mph	(VOC) 75%(1975) 68%(2005) 72%(2025)	39%(1975) 26%(2000) 28%(2025)	16%(1975) 25%(2000) 21%(2025)
		35mph	-9%	-8%	-5%(1975) 0%(2000) -6%(2025)
	max.	65mph	(VOC) -26%(1975) -22%(2025)	0%(1975) 17%(2000) 13%(2025)	10%(1975) 29%(2000) 14%(2025)
Facility VMT (Add and subtract fraction of vehicles to/from freeways and arterials: new_freeway + new_ramp=(old_freeway + old_ramp) + x*old_arterial new ramp= 0.08*(new_ramp + new_freeway) new_freeway=(0.92/0.08) * new_ramp new_arterial=(1-x)*old_arterial	min.	subtract 40% from arterials	(NMHC) -1%(1975) -0.5%(2020)	1%(1975) 3%(2025)	1%(1975) 5%(2000) 2%(2020)
	max.	add 40% to arterials	(NMHC) 1%(1975) 0%(2007)	-2%(1975) -3%(2025)	-1%(1975) -5%(2000) -2%(2020)
Fuel Program/Sulfur Content (calendar years 2000 and later; for default conventional eastern program reduce sulfur content by 10%, 20%, and 30%)	min.	-10%	(NMHC) 0% (2010) to -0.5%(2000)	-0.2%(2010) to -1.3%(2000)	-0.4%(2000) to -0.5%(2025)
	max.	-30%	(NMHC) -0.05%(2010) to -1.4%(2000)	-0.7%(2010) to -4%(2000)	-1%(2000) to -2%(2025)
Fuel Reid Vapor Pressure(RVP) (The RVP was increased from 6.5lb/in^2 to 11.5lb/in^2 for a number of calendar years between 1975 and 2050 with minimum and maximum temperatures 72°F and 92°F, respectively. Percent differences were determined relative to 7.5lb/in^2)	min.	6.5lb/in^2	-3%(1985) to -6%(2005)	0% (1975-2050)	approx. 0%
	max.	11.5lb/in^2	77%(2005) to 38%(1985)	101%(2050) to 2%(1975)	3%(2050) to -0.6%(1985)

Table A.2. All Vehicle Summary (Continued)

COMMAND	Change in Input		Change in Hydrocarbon emissions	Change in CO emissions	Change in Oxides of Nitrogen emissions
Mileage Accumulation(increase and decrease mileage accumulation relative to the MOBILE6 defaults)	min.	20% decrease	(NMHC) 3%(1980) 4%(2005) 3%(2015) 0.2%(2020)	–1.7%(1985) to -7.9%(2020)	3%(1990) to -12%(2020)
	max.	20% increase	(NMHC) 1%(1990) -1%(2000) 1%(2005) 3%(2020)	3%(1990) to 11%(2020)	-2%(1980) to 13%(2020)
Oxygenated Fuels (ether concentration from 1% to 2.7%; market share variations from 5% to 50%)	min.	5% mkt, 1%ether, 0% alcohol	(NMHC) approx. 0%	approx. 0%	0%
	max.	50% mkt, 0%ether, 2.7% alcohol	(NMHC) -2% (2000)to -3%(2020)	-5%(2000) to -3%(2020)	0%
Oxygenated Fuels (alcohol concentration from 0.7% to 3.5%; market share variations from 5% to 50%)	min.	50% mkt, 0%ether, 0.7% alcohol	(NMHC) approx. 1% (2000)to (2020)	<1% (2000) to (2020)	0%
	max.	50% mkt, 0%ether, 3.5% alcohol	(NMHC) -0.5% (2000)to -1%(2020)	-5%(2000) to -2%(2020)	0%
Registration Distribution(decrease newer vehicle fractions and increase older vehicle fractions)	min.	5% age shift	(NMHC) 5%(1985) to 31%(2015)	3%(1980) to 21%(2000)	1%(1985) to 12%(2020)
	max.	20% age shift	(NMHC) 13%(1975) to 74%(2015)	9%(1975) 47%(1995) 22%(2020)	1%(1980) to 38%(2020)
Speed VMT (Arterial; -3% - null low speed vehicle fractions 9% - equal vehicle fractions for all speeds 14% - increase low speed vehicle fraction by 10% 21% - increase low speed vehicle fraction by 20% 29% - increase low speed vehicle fraction by 30%)	min.	-3% (free-flow/ all day non-rush hour speeds)	(NMHC) -3%	approx. -1%	-3% to -0.5%
	max.	29%(congested traffic flow ;i.e., 30% of rush hour "free-flow" vehicles at the lower speeds)	(NMHC) 35%(1975) 33%(1985) 39%(2050)	21%(1975) 13%(2005) 15%(2020)	5%(1975) to 8%(2050)
Speed VMT (Freeway; reduce fraction of vehicles from high speeds to lower speeds)	min.	-50% (equal distribution of speeds)	(NMHC) 12%(1975) 10%(2020) 11%(2050)	+3%(1975) -1%(2000) 0%(2050)	0%(1975) -1%(1995) -2%(2005) 0%(2050)
	max.	10%(most vehicles at the higher speeds)	(NMHC) -4%(1975) -3%(1985) -4%(2050)	-3%(1975) -2%(1995) -1%(2020)	approx. -1%
Starts Per Day(change the number of starts per day from -50% to +50% in increments of 10% for each vehicle type)	min.	-50%	(NMHC) -17%(2025) to -13%(1975)	-16%(1975) to -13%(2025)	-10%(1975) to -7%(2025)
	max.	50%	(NMHC) 17%(2025) to 14%(1975)	14%(2025) to 15%(1975)	10%(1975) to 7%(2025)
Start Distribution	compare emissions with default hourly start fractions to a constant fraction of starts for each hour of the day		(NMHC) 0%(1975) to 3%(2025)	1%(1975) to 3%(2025)	2%(1975) to 1%(2025)

Table A.2. All Vehicle Summary (Continued)

COMMAND	Change in Input		Change in Hydrocarbon emissions	Change in CO emissions	Change in Oxides of Nitrogen emissions
Sulfur Content (calendar years 1999 and earlier)	min.	10%	(NMHC)-0.2% (1999) to 0%(1975)	-14%(1999) to 0%(1975)	3%(1999) to0%(1975
	max.	-90%	(NMHC)-4% (1999) to 0% (1975)	0.8%(1999) to 0% (1975)	0.3%(1999) to 0%(1975)
Temperature, Average Daily (standard temperature cycle and vary average daily temperature 12 to 107) F)	min.	12° F	17%(2025); 34%(1995) -6%(1975)	0%(1975) to 162%(2025)	41%(1975) to 22%(2025)
	max.	107° F	11%(2025) 26%(1995) 31%(1975	56%(1975) to 3%(2025)	-15%(1975) to7%(2025)
Temperature Cycles (keep average temperature a constant and vary the standard temperature cycle)	min.	constant temperature (-100%)	(NMHC) -3%(1975,42 °F) -2%(1975,102 °F) -8%(2000,82°F) 1%(2025,42 °F) 3%(2025,102°F)	-11%(1975, 102°F) -1%(1975,42 °F) 6%(2025,42 °F) -1%(2025,102 °F)	1%(1975,42°F) 4%(1975,102°F) -1%(2025,102°F)
	max.	34° F temperature range (+42%)	1%(1975,42 °F) 2%(1975,102 °F) 6%(2005,82 °F) 1%(2025,42 °F) 3%(2025,102 °F)	0%(1975,42 °F) 5%(1975,72 °F) 3%(1975,102 °F) -2%(2025,42°F) 0%(2025,102 °F)	1%(1975,82°F) to -1%(2025,72°F)
Temperature, Average Daily and Humidity [For each of a set of daily average temperatures (42, 72, 82, 92, 102, and 107) F) with a 24) F temperature range (the difference between the minimum and maximum temperatures is 24) F) variations of absolute humidity are made. Emissions results are determined and compared for each of these average daily temperatures with the absolute humidity set to 53.7, 75, 98.5, 107, and 149.5 grains/lb.]	min.	-28% (54grains/lb)	(NMHC) <0% and >-1%(all temperatures and all years)	<1% and >-1%(all temperatures and all years)	5%(2025) 3%(2005) 3%(2000) 5%(1975)
	max.	100% (150grains/lb)	(NMHC) >0% and <1% (all temperatures and all years)	<4% and >0%(all temperatures and all years)	-12%(2025) -7%(2005) -6%(2000) -12%(1975)

Table A.3. Affects of the relative proportion Heavy and Light Duty Trucks (VMT MIX command) on emissions from Heavy and Light Duty Vehicles

COMMAND	Change in Input		Change in Hydrocarbon emissions	Change in CO emissions	Change in Oxides of Nitrogen emissions
VMT Mix (Effects on Light-Duty Trucks Emissions Only) (The vehicle miles traveled fractions for light-duty trucks 2 were increased and decreased while holding the total proportion of vehicle miles traveled by all light-duty trucks constant and equal to the MOBILE6 default values for calendar years 1975, 2000, 2005, 2007, and 2020)	Min.	all LDT vehicle miles traveled fractions equal (approx. a 55% decrease in LDT2 fractions)	(NMHC) LDGT 8%(1975) 13%(2020) LDDT 0%(1975) -21%(2000) 0%(2020)	LDGT 5%(1975) 12%(2000) 5%(2020) LDDT 0%(1975) -19%(2000) 0%(2020)	LDGT 4%(1975) 5%(2000) 18%(2020) LDDT 0%(1975) 4%(2000) 0%(2020)
	Max.	increase vehicle miles traveled fractions for LDT2 by 20%	(NMHC) LDGT -5%(1975) -2%(2000) -3%(2020) LDDT 0%(1975) 8%(2000) 0%(2020)	LDGT -3%(1975) -1%(2020) LDDT 0%(1975) 8%(2000) 0%(2020)	LDGT -3%(1975) -1%(2000) -3%(2020) LDDT 0%(1975) 4%(2000) 0%(2020)
VMT Mix (Effects on Heavy-Duty Truck Emissions Only) (The vehicle miles traveled fractions for heavy-duty vehicles were increased and decreased while holding the total proportion of vehicle miles traveled by all heavy-duty vehicles constant and equal to the MOBILE6 default values for calendar years 1975, 2000, 2005, 2007, and 2020)	Min.	all HDV vehicle miles traveled fractions equal (approx. a 60% decrease in HD2B and HD8B fractions)	(NMHC) HDGV 15%(1975) 37%(2000) 31%(2020) HDDV -10%(1975) -20%(2000) -15%(2020)	HDGV 19%(1975) 49%(2000) 15%(2020) HDDV -8%(1975) -28%92000) -17%(2020)	HDGV 19%(1975) 11%(2020) HDDV -7%(1975) -26%(2000) -17%(2020)
	Max.	increase vehicle miles traveled fractions for HDV2B and HDV8B by 20%	(NMHC) HDGV 0%(1975) -6%(2000) -5%(2020) HDDV 0%(1975) 4%(2000) 3%(2020)	HDGV 0%(1975) -8%(2000) -2%(2020) HDDV 0%(1975) 6%(2000) 4%(2020)	HDGV 0%(1975) -2%(2020) HDDV 0%(1975) 5%(2000) 4%(2020)

Table A.4. Summary of LDGV results with input parameters which have minor (small) effects on emissions (changes which are less than 5%).

COMMAND	Change in Input		Change in Hydrocarbon emissions	Change in CO emissions	Change in Oxides of Nitrogen emissions
Absolute Humidity [Use high and low humidity values from August morning and afternoon average relative humidity values from Atlanta and Tucson (National Weather Service data).]	min.	-28% (54grains/lb)	(NMHC) ldgv running <-1% ldgv total:<0.5%	ldgv running -1.9%(2000) to -0.6%(2025)	Medium Level
	max.	100% (149grains/lb)	(NMHC) ldgv running:4% ldgv total:<0.5%	ldgv running 2.3%(2025) to 8.4%(2000)	Medium Level
Air Conditioning	Emissions Differences with Air Conditioning Correction Applied and Not Applied		2%(1975) 2%(2005) 0%(2025)	Medium Level	Medium Level
Average Daily Temperature and Humidity [For each of a set of daily average temperatures (42, 72, 82, 92, 102, and 107 F) with a 24 F temperature range (the difference between the minimum and maximum temperatures is 24 F) variations of absolute humidity are made. Emission results are determined and compared for each of these average daily temperatures with the absolute humidity set to 53.7, 75, 98.5, 107, and 149.5 grains/lb. for a range of calendar years.]	min.	-28% (54grains/lb)	(NMHC) –1% to 0% (all temperatures and all years)	–2% to 0% (all temperatures and all years)	Medium Level
	max.	100% (150grains/lb)	(NMHC) 0% to 1% (all temperatures and all years)	0% to 6% (all temperatures and all years)	Medium Level
Facility VMT [Add and subtract fraction of vehicles to/from freeways and arterials: New_freeway + new_ramp=(old_freeway + old_ramp) + x*old_arterial New ramp= 0.08*(new_ramp + new_freeway) new_freeway=(0.92/0.08) * new_ramp New_arterial=(1-x)*old_arterial]	min.	subtract 40% from arterials	(NMHC) -1%(1975) 0%(2000)	2%(1975) 4%(2000) 3%(2020)	1%(1975) 5%(2000) 2%(2020)
	max.	add 40% to arterials	(NMHC) 1%(1975) 0%(2007)	-1%(1975) -4%(2005) -3%(2020)	-1%(1975) -5%(2000) -2%(2020)
Fuel Program/Sulfur Content (calendar years 2000 and later; for default conventional eastern program reduce sulfur content by 10%, 20%, and 30%)	min.	-10%	(NMHC) -0.5% (2000) to 0%(2025)	-1.6%(2000) to -0.6%(2025)	-0.7%(2000) to 0%(2025)
	max.	-30%	(NMHC) -1.5%(2000) to -0.5%(2025)	-4.7%(2000) to -2%(2025)	-2.2%(2000) to -3.7%(2025)
Hourly Temperature (hourly temperatures using temperature cycle variations: The percent differences here are for a given hour of the day and model year. They are not results which have been averaged over an entire day. The daily averages tend to lessen the effects.)	min.	constant temperature (-100%)	(NMHC) 12% to -13% (102 F)	-35%((102 F) to 27%(92 F)	-24%(102 F) to 11%(92 F)
	max.	34 F temperature range (+42%)	(NMHC) -5%(102 F) to 3%(72 F)	-11%(92 F) to 7%(72 F)	-5%(92 F) to 4%(72 F)
Mileage Accumulation(increase and decrease mileage accumulation relative to the MOBILE6 defaults)	min.	20% decrease	(NMHC) 3%(1980) 5%(2005) 1%(2015) -2%(2020)	Medium Level	Medium Level
	max.	20% increase	(NMHC) 1%(1990) -2%(2000) -3%(2005) 2%(2020)	Medium Level	Medium Level

Table A.4. Summary of LDGV results with input parameters which have minor (small) effects on emissions (changes which are less than 5%). (Continued**)**

COMMAND	Change in Input		Change in Hydrocarbon emissions	Change in CO emissions	Change in Oxides of Nitrogen emissions
Oxygenated Fuels (ether concentration from 1% to 2.7%; market share variations from 5% to 50%)	min.	5% mkt, 1%ether, 0% alcohol	(NMHC) 0%(2005& 2020)	Approximately 0% (all years)	0%
	max.	50% mkt, 0%ether, 2.7% alcohol	(NMHC) -2% (2000) to -2%(2020)	-5%(2000) to -3%(2020)	0%
Oxygenated Fuels (alcohol concentration from 0.7% to 3.5%; market share variations from 5% to 50%)	min.	50% mkt, 0%ether, 0.7% alcohol	(NMHC) 1% (2000) to 2%(2020)	0.3%(2000) to 2%(2020)	0%
	max.	50% mkt, 0%ether, 3.5% alcohol	(NMHC) Approximately 0% (all years)	-5%(2000) to -2.5%(2020)	0%
Speed VMT (Arterial; -3% - null low speed vehicle fractions 9% - equal vehicle fractions for all speeds 14% - increase low speed vehicle fraction by 10% 21% - increase low speed vehicle fraction by 20% 29% - increase low speed vehicle fraction by 30%)	min.	-3% (free-flow/ all day non-rush hour speeds)	High Level	3% (all years)	-1% to 0% (all years)
	max.	29%(congested traffic flow,i.e., 30% more vehicles at the lower speeds)	High Level	-2%(2005) to +3%(1975)	5%(1975) to 8%(2050)
Speed VMT (Freeway; reduce fraction of vehicles from high speeds to lower speeds)	min.	-50% (equal distribution of speeds)	Medium Level	3%(1975) to -2%(2005)	-1.1%(2050) to -0.5%(1985)
	max.	10%(most vehicles at the higher speeds)	(NMHC)- 3.5%(1975) to -1%(2010)	< 0% and >-2%	+1.6%(1985) to 2%(2050)
Start Distribution	Compare emissions with default hourly start fractions to a constant fraction of starts for each hour of the day		(NMHC) 4.5%(1975) to 0.4%(2025)	3%(1975) to 0%(2025)	3%(1975) to 1%(2025)
Sulfur Content (calendar years 1999 and earlier)	min. (300ppm)	0%	(NMHC) 0% (1975) to -0.5%(1999)	0%(1975) to -1%(1999)	0%(1975) to -1%(1999)
	max. (30ppm)	-90%	(NMHC) 0% (1975) to -3.5% (1999)	0%(1975) to -1%(1999)	0%(1975) to -7%(1999)
Temperature Cycles (keep average daily temperature a constant and vary the standard temperature cycle)	min.	Constant temperature (-100%)	(NMHC) -3%(1975,102·F) -2%(1975,42·F) 14%(2025,102·F) -1%(2025,42·F) -8%(2005,82·F)	-11%(1975,102·F) -2%(1975,42·F) -0.5%(2025, 102·F) 5%(2025,42·F) 5%(2005,42·F)	5%(1975,102·F) 1%(1975,42·F) -1.4%(2025,102·F) 1%(2025,42·F) -8%(2025,75·F)
	max.	34·F temperature range (+42%)	(NMHC) 3%(1975,102·F) 2%(1975,42·F) 3%(2025,102·F) 2%(2025,42·F) 6%(2005,82·F)	4%(1975,102·F) 1%(1975,42·F) -0.3%(2025, 102·F) -2%(2025,42·F) -2%(2005,42·F)	-1%(1975,102·F) -1%(1975,42·F) -1%(2025,102·F) -1%(2025,42·F) 8%(2025,75·F)

USCG Comment #31:

The modeling results discussed in Section 6.4 of Exhibit X indicate that there are significant impacts for all pollutants except the 1- and 8-hour CO, and the annual PM10. The Significant Impact Area (SIA) for PM should be revisited based on comments above on the necessity to include emissions from carriers and tugs and to include the condensable fraction of PM for all sources. In addition, for NAAQS compliance, only background levels are added to the facility impacts, but EPA and DEC guidance require a cumulative source analysis for all pollutants having a significant impact. Since certain SIAs are close to shoreline, a cumulative analysis with onshore sources should be performed.

Response:

ASIG has requested a meeting with EPA to discuss this comment. After consultation with EPA, a response will be provided.

USCG Comment #32:

In section 3.2.3 of the biological resources section of volume three, please provide the references for the seasonality of phytoplankton and zooplankton abundance in the New York Bight.

Response:

The seasonality and abundance of both phytoplankton and zooplankton in the New York Bight are presented in *Significant Habitat and Habitat Complexes of New York Bight* (USFWS 1997) and *Plankton Systematics and Distribution* (Malone 1977). Phytoplankton seasonality in Raritan Bay is presented in *Species Diversity in Net Phytoplankton of Raritan Bay* (Patten 1962). Malone (1977) provides the more detailed information about phytoplankton and zooplankton community composition in the Hudson River estuary, the inner bight and the outer shelf areas.

Electronic copies of the literature cited have been provided in the "Requested References" File accompanying this data response submittal.

Reference:

Malone, Thomas C. 1977. Plankton Systematics and Distribution. MESA (Marine EcoSystems Analysis) Program, MESA New York Bight Project. Monograph 13.

Patten, Bernard C. 1962. Species Diversity in Net Phytoplankton of Raritan Bay. Journal of Marine Research, 20:57-75.

USFWS (U.S. Fish and Wildlife Service). 1997. Significant Habitat and Habitat Complexes of the New York Bight. Available online at http://training.fws.gov/library/pubs5/begin.htm

USCG Comment #33:

In section 1.1.2.1 of the general project description contained in volume three, the environmental benefits of the installation include "creating potential habitat for migratory birds." Please provide a list of migratory bird species that utilize the project area and their preferred habitat.

Response:

The surface of the island will consist of a combination of paved surfaces, structures, and graded sand. While the island will not have a "natural" appearance and industrial-type activity will not generally be attractive to avian wildlife (especially since lighting will adhere to USFWS recommendations to minimize attraction to birds), it is possible, and perhaps likely, that some individuals migrating along the Atlantic Flyway could use the island surface as a temporary resting site, particularly as a refuge during stormy conditions. Species that might use the Island this way could include the gulls, terns, and migratory shorebirds listed in Volume Three, Part One – Topic Report Three, Table 3-17 as well as songbirds that stray over open water.

Of the species of charadriiformes identified as having a relative abundance of common on Table 3-17, the herring gull and great black-backed gull could also potentially use the island for nesting or more frequent visits. Both species breed on islands, are present in coastal waters year-round, and are adapted to coexistence with human activity (Cornell Lab of Ornithology 2008a and 2008b).

USCG Comment #34:

In section 3.2.1 of the biological resources section of volume three, please provide the reference that documents the maximum depth of occurrence for seagrass and marsh grass.

Response:

Eelgrass (Zostera marina) is the dominant species of seagrass, and the only one found in marine waters in the New York region (Thayer et al 1984). Eelgrass depth distribution appears to be limited by available light (within its temperature and salinity ranges), which is largely dependent upon water clarity (Thayer et al 1984). In relatively clear waters, maximum depth limits for eelgrass can exceed 32.8 feet (10 meters) (Thayer et al 1984). No eelgrass was observed in any of the remotely operated vehicle (ROV) footage shot along the pipeline route (Deepwater Port application, Volume Five, Part One, Attachment 3-1) although this survey was conducted in the early part of the growing season (May) when vegetation would not have been as lush as during mid-summer. The shallowest depth of any portion of the proposed Safe Harbor facility, however, is at the interconnect with the Transco pipeline, approximately 48-50 feet at mean low water, below the cited maximum depth for clear waters, so it is unlikely that eelgrass would be present there.

The marsh grasses referred to in this section (e.g., Spartina alterniflora) are intertidal (USFWS 1997).

Thayer, G. W., Kenworthy, W. J., and Fonseca, M. S., 1984, The ecology of eelgrass meadows of the Atlantic coast: a community profile: U.S. Fish and Wildlife Service, FWS/OBS-84/02, 147p.

The reference is also available online at: http://www.nwrc.usgs.gov/diglib.htm#comprofs

USFWS (United States Fish and Wildlife Service). 1997. Significant Habitats and Habitat Complexes of the New York Bight Watershed. United States Fish and Wildlife Service, Southern New England – New York Bight Coastal Ecosystems Program. Charlestown, Rhode Island. November 1997.

The reference is also available online at: http://training.fws.gov/library/pubs5/web_link/text/toc.htm

Electronic copies of the literature cited have been provided in the “Requested References” File accompanying this data response submittal.

USCG Comment #35:

In section 3.2.2.1 of the biological resources section of volume three, please provide the reference that documents that a sandy substrate "tends to support an infaunal benthic community".

Response:

This is a very general statement regarding sandy seafloor environments and its support of benthic infaunal communities. There is a body of literature that describes and discusses benthic infaunal communities associated with high-energy marine subtidal sand-bottom habitats. An example of a reference to support this statement is:

Brooks, R. A., S. S. Bell, C. N. Purdy, and K. J. Sulak. 2004. The benthic community of offshore sand banks: a literature synopsis of the benthic fauna resources in potential MMS OCS sand mining areas. USGS Outer Continental Shelf Studies Ecosystem Program Report USGSSIR- 2004-5198 (CEC NEGOM Program Investigation Report No. 2004-01, February 2004); Minerals Management Service, OCS Study MMS-2004.

Electronic copies of the literature cited have been provided in the "Requested References" File accompanying this data response submittal.

USCG Comment #36:

In section 3.2.2.2 of the biological resources section of volume three, please provide the reference that documents microbiota, meiofauna, and macrofauna size ranges.

Response:

Size ranges for macrofauna, meiofauna, and microbiota are available in:

USFWS (United States Fish and Wildlife Service). 1997. Significant Habitats and Habitat Complexes of the New York Bight Watershed. United States Fish and Wildlife Service, Southern New England – New York Bight Coastal Ecosystems Program. Charlestown, Rhode Island. November 1997.

The reference is also available online at: http://training.fws.gov/library/pubs5/web_link/text/toc.htm

Size ranges are referenced in:

WPWS. 2008 Significant Habitats and Habitat Complexes of the New York Bight Watershed – Habitat Complexes by Geographical Region. Accessed on October 8, 2008. Available at: http://training.fws.gov/library/pubs5/web_link/text/marizone.htm#Continental%20 Shelf%20Zone

The macrofaunal (>0.5 mm) and meiofaunal (0.063 - 0.5 mm) size ranges are also referenced in:

Brooks, R. A., S. S. Bell, C. N. Purdy, and K. J. Sulak. 2004. The benthic community of offshore sand banks: a literature synopsis of the benthic fauna resources in potential MMS OCS sand mining areas. USGS Outer Continental Shelf Studies Ecosystem Program Report USGSSIR- 2004-5198 (CEC NEGOM Program Investigation Report No. 2004-01, February 2004); Minerals Management Service, OCS Study MMS-2004.

Electronic copies of the literature cited have been provided in the “Requested References” File accompanying this data response submittal.

USCG Comment #37:

In section 3.2.2.2 of the biological resources section of volume three, please provide the reference that documents which sessile organisms may attach to cobbley or gravelly habitat.

Response:

This section lists common taxa or faunal groups expected to inhabit cobble or gravel substrates in the Project area. Faunal communities of such habitats in the Middle Atlantic Bight are reviewed in:

Steimle, F. W., & Zetlin, C. (2000). Reef habitats in the middle atlantic bight: Abundance, distribution, associated biological communities, and fishery resource use. Marine Fisheries Review, 62(2), 24-42. Retrieved from http://spo.nwr.noaa.gov/mfr622/mfr6222.pdf

Electronic copies of the literature cited have been provided in the "Requested References" File accompanying this data response submittal.

USCG Comment #38:

In section 3.2.3 of the biological resources section of volume three, please provide the references that document the depth range and feeding capabilities of dinoflagellates as well as the reference for the mass mortalities caused by red and brown tides.

Response:

A very brief and generalized summary of dinoflagellate biology and red tides is presented in *Significant Habitat and Habitat Complexes of New York Bight* (USFWS 1997).

Electronic copies of the literature cited have been provided in the "Requested References" File accompanying this data response submittal.

Reference:

USFWS (U.S. Fish and Wildlife Service). 1997. Significant Habitat and Habitat Complexes of the New York Bight. Available online at http://training.fws.gov/library/pubs5/begin.htm.

USCG Comment #39:

In section 3.3.3 of the biological resources section of volume three, please provide the average annual density of phytoplankton and zooplankton in the New York Bight and references for the values.

Response:

Both USFWS (1997) and Malone (1977) present phytoplankton and zooplankton abundances on a seasonal basis, due in part to large fluctuations in densities attributed to seasonal changes. USFWS (1997) states spring and fall phytoplankton blooms may attain cell concentrations of 1x105 to 1x108 cells/liter in the New York Bight Apex where the Safe Harbor Project is located. Malone (1977) states that cell densities of 1x104 to 1x107 cells/liter for the area of the Bight where the proposed Terminal is to be located. Outer Bight phytoplankton densities tend to be lower. Malone (1977) presents zooplankton abundance by taxonomic group, with both copepods and meroplankton densities ranging from less than 1x103 to 1x105 individuals per cubic meter. Marshal (1984) shows average annual densities of phytoplankton in the inner New York Bight ranging from 1x105 to 1x107 cells/liter. Zooplankton densities reported in scientific literature may vary depending on the mesh-size used to sample. Marshal (1984) was not cited in Section 3.3.3.

Electronic copies of the literature cited have been provided in the "Requested References" File accompanying this data response submittal.

Reference:

Malone, Thomas C. 1977. Plankton Systematics and Distribution. MESA (Marine EcoSystems Analysis) Program, MESA New York Bight Project. Monograph 13.

Marshal, H.G. 1984. Phytoplankton distribution along the eastern coast of the USA. Part V. Seasonal density and cell volume patterns for the northeastern continental shelf. J. Plankton Research 6:1(169-193).

USCG Comment #40:

At the end of section 3.3.5.1 of the biological resources section of volume three, please provide a reference that shows that planktonic eggs and larvae are found primarily in the upper portions of the water column, and would therefore avoid any impacts from turbidity.

Response:

Comment #40 misrepresents the analysis at the end of Section 3.3.5.1 (describing impacts to Essential Fish Habitat associated with construction of the Island) when the commenter states *"…and would therefore avoid **any** impacts from turbidity."* (emphasis added). The actual paragraph that the commenter is referring to discusses the turbidity associated with construction of the terminal, specifically the anchoring of construction vessels and placement of fill. The paragraph specifically says *"Most planktonic eggs and larvae will be located in the upper portions of the water column and would have **limited exposure to turbidity generated this way because it will occur primarily in the lower portion of the water column"*** (emphasis added). As discussed in response to Comments 49 and 97, several operations have the potential to produce a temporary increase in turbidity or suspended sediments. Modeling conducted to assess the water quality effects of pipeline installation (included in Volume Five, Part One, Attachment 3-4), showed results that suggested this is the greatest potential source of suspended sediments. The responses, which were extrapolated from those results, indicated that turbidity effects would be experienced in the lower half of the water column. Please refer to these responses for further details.

Because of the timing of marine construction (May through October), only ichthyoplankton present during this period have the potential to be exposed to turbidity. The following paragraph and accompanying table on seasonal distribution of fish larvae was presented in the supplemental filing, Volume Five, Part One, Section 3.3.

Ichthyoplankton resources in the Project area were described in the Deepwater Port Application (Volume Three, Part One, Topic Report Three Biological Resources) based on data developed by National Marine Fisheries Service (NMFS) during the Marine Resources Monitoring Assessment and Prediction Program (MARMAP) conducted between 1977 and 1987. Subsequently, NMFS has been conducting a similar ichthyoplankton survey, the Ecological Monitoring Program (ECOMON) that covers the same geographic area as MARMAP. Data for the New York Bight area have been made available to the Project for 2004-2005. Like the MARMAP program, sampling for the ECOMON program occurs six times a year. Although the longer database for the MARMAP program results in having some data points in the New York Bight during every month, such is not the case with the available ECOMON data. For the purposes of modeling the impacts of the Safe Harbor Energy Project on ichthyoplankton resources, the two databases were combined for selected species. Monthly abundances are presented in Table 40-1.

Table 40-1. Monthly Average Density (number per 100 m3) of yolk-sac larvae (YSL) and post yolk-sac larvae (PYSL) of selected fish species in the New York Bight apex regional from MARMAPb (1977-1987) and ECOMON (2004-2005) data during the Safe Harbor marine construction period.

Species	Life Stage	May (n=11)	Jun (n=9)	Jul (n=11)	Aug (n=10)	Sep (n=5)	Oct (n=9)
Atlantic cod	YSL	0.23	0	0.05	0	0	0
	PYSL	0.21	0.1	0	0	0	0
Atlantic mackerel	YSL	197.98	456.58	0	0.33	0	0
	PYSL	22.16	6.61	0	0	0	0
Atlantic menhaden	YSL	0.01	0	0	0	0	0

Species	Life Stage	May (n=11)	Jun (n=9)	Jul (n=11)	Aug (n=10)	Sep (n=5)	Oct (n=9)
	PYSL	0	0	0	0	0	0
Bay anchovy	YSL	0	0	0	0	0	0
	PYSL	0	0	0	0.27	0	0
Black sea bass	YSL	0	0	0	0.59	0.08	0
	PYSL	0	0	0.13	1.48	1.31	0.89
Butterfish	YSL	0	0	1.01	0.98	0.2	0
	PYSL	0	0.23	7.11	13.99	1.06	0.14
Hakes	YSL	0	0.04	0.09	2.88	1.84	2.27
	PYSL	0	0.16	5.17	15.4	13.87	17.5
Sand lances	YSL	0.1	0	0	0	0	0
	PYSL	10.75	0.02	0	0	0	0
Silver hake	YSL	0.02	0.04	0.35	0.33	0.07	0.18
	PYSL	0	0.22	0.31	0.77	0.08	0.38
Summer flounder	YSL	0	0	0	0	0	1.55
	PYSL	0	0	0	0	0	1.15
Tautog	YSL	0	0	0.03	0.3	0	0
	PYSL	0	0	0.76	0.27	0	0.21
Yellowtail flounder	YSL	2.78	8	0	0	0	0
	PYSL	9.93	40.32	1.43	0	0	0

[a] Region in the New York Bight bounded by the coordinates 40°00’ to 40°35’ N and 73°00’ to 73°55’ W
[b] MARMAP data was adjusted for net extrusion with correction factors for 0.333 mesh bongo nets as used in ECOMON
n=number of samples

While Table 40-1 does not include all of the larval fish species that may occur during the construction period, it lists the regionally-important, federally managed species as well as two ecologically important species (bay anchovy and sand lance). Five species would be expected to be relatively abundant within the construction time frame. Between May and October, sand lance larvae occur primarily in May and Atlantic mackerel and yellowtail flounder larvae predominate in May and June. Hakes exhibit a prolonged presence from July through October while butterfish exhibit their highest abundances in July and August. Locke and Courtnenay (1995) reported that larval sand lance occurred mainly at the surface at the mouth of the Inner Bay of the Miramichi estuary. Studholme et al. (1999) provided references that showed although Atlantic mackerel larvae undergo a diurnal vertical migration, it ranges from the thermocline to the surface (Sette 1943) and is focused increasingly towards the surface as the larvae grow (Ware and Lambert 1985). Yellowtail flounder larvae also migrate vertically, with peak numbers at the thermocline during the day and higher in the water column at night (Smith et al. 1978). Kendall and Naplin (1981) found that hake and butterfish larvae were most abundant in about the middle of the water column. Kendall and Naplin (1981) also found that eggs of all species collected were concentrated near the surface.

References:

Kendall, A.W. and N.A. Naplin. 1981. Diel-depth distribution of summer ichthyoplankton in the Middle Atlantic Bight. Fish. Bull. 79(4): 705-726.

Locke, A. and S.C. Courtenay. 1995. Ichthyoplankton and Invertebrate Zooplankton of the Miramichi Estuary: 1918-1993, p. 97-120. In E.M.P. Chadwick (editor). Water, Science and the Public: the Miramichi ecosystem. Can. Spec. Publ. Fish. Aquat. Sci. 123.

Sette, O.E. 1943. Biology of Atlantic mackerel (Scomber scombrus) of North America. Part I: Early life history including growth, drift, and mortality of the egg and larval populations. U.S. Fish Wildl. Serv. Fish. Bull. 50: 149-237. Cited in: Studholme, A.L., D.B. Packer, P.L.Berrien, D.L.Johnson, C.A. Zetlin, and W.W. Morse. 1999. Essential Fish Habitat Source Document: Atlantic mackerel, Scomber scombrus, Life History and Habitat Characteristics. NOAA Technical Memorandum NMFS-NE-141.

Smith, W.G., J.D. Sibunka, and A. Wells. 1978. Diel movements of larval yellowtail flounder, Limanda ferruginea, determined from discrete depth sampling. Fish. Bull. 76(1): 167-178.

Studholme, A.L., D.B. Packer, P.L.Berrien, D.L.Johnson, C.A. Zetlin, and W.W. Morse. 1999. Essential Fish Habitat Source Document: Atlantic mackerel, Scomber scombrus, Life History and Habitat Characteristics. NOAA Technical Memorandum NMFS-NE-141.

Ware, D.M. and T.C. Lambert. 1985. Early life history of atlantic mackerel (Scomber scombrus) in the southern Gulf of St. Lawrence. Can. J. Fish. Aquat. Sci. 42: 577-592. Cited in: Studholme, A.L., D.B. Packer, P.L.Berrien, D.L.Johnson, C.A. Zetlin, and W.W. Morse. 1999. Essential Fish Habitat Source Document: Atlantic mackerel, Scomber scombrus, Life History and Habitat Characteristics. NOAA Technical Memorandum NMFS-NE-141.

USCG Comment #41:

In section 3.3.9.3 of the biological resources section of volume three, please provide a reference that documents the habitat used by Atlantic salmon and shortnose sturgeon.

Response:

Anadromous Atlantic salmon spawn in fresh waters where juveniles remain for one to several years (NMFS 2007). The historical range for spawning anadromous Atlantic salmon extended to the Housatonic River in Connecticut (NMFS 2007). Salmon populations are now substantially reduced and the southern range limit for naturally reproducing Atlantic salmon is in the Gulf of Maine (NMFS and USFWS 2005, NMFS 2007). Upon returning to marine waters, salmon undertake extensive feeding migrations, with U.S. salmon migrating to waters off Newfoundland, Labrador and west Greenland (NMFS 2007).

The Hudson River likely supports the largest remaining population of shortnose sturgeon (NMFS 1998). Although shortnose sturgeon may occasionally enter marine waters, they are primarily confined to rivers and estuaries (NMFS 1998). Occurrence in near-shore, shallow, ocean waters has been reported, but is not well documented (NMFS 1998).

References:

NMFS (National Marine Fisheries Service). 2007. Species of Concern, NOAA National Marine Fisheries Service, Atlantic salmon (Salmo salar). National Marine Fisheries Service, Silver Spring, MD. 5pp.

The reference is also available online at: http://www.nmfs.noaa.gov/pr/species/concern/

NMFS and USFWS (National Marine Fisheries Service and U.S. Fish and Wildlife Service). 2005. Recovery Plan for the Gulf of Maine Distinct Population Segment of Atlantic Salmon (Salmo salar). National Marine Fisheries Service, Silver Spring, MD. 325pp.

The reference is also available online at: http://www.nmfs.noaa.gov/pr/species/fish/atlanticsalmon.htm

NMFS (National Marine Fisheries Service). 1998. Recovery Plan for the Shortnose Sturgeon (Acipenser brevirostrum). Prepared by the Shortnose Sturgeon Recovery Team for the National Marine Fisheries Service, Silver Spring, Maryland. 104 pages.

The reference is also available online at: http://www.nmfs.noaa.gov/pr/species/fish/shortnosesturgeon.htm

Electronic copies of the literature cited have been provided in the “Requested References” File accompanying this data response submittal.

USCG Comment #42:

Please provide an electronic copy of the following references:

Berrien and Sibunka 1999	**NMFS 1999b**
Berrien et al. 1978	**NMFS 2001a**
Byron Young, NYSDEC, pers. comm., 2001	**NMFS 2001e**
Cargnelli et al. 1999a	**NOAA 2001**
Cargnelli et al. 1999b	**NOAA Fisheries 2006**
Cargnelli et al. 1999c	**NOAA Fisheries/NERO 2005**
Casey et al. 1987	**Packer et al. 1999**
Chang et al. 1999	**Packer et al. 2003a**
Cross et al. 1999	**Patten 1962**
Fahay et al. 1999	**Pereira et al. 1999**
Jacobson 2005	**Reid et al. 1999**
Johnson et al. 1999	**SAFMC 1998**
Lock and Packer 2004	**SAFMC 2004**
MAFMC 1998a	**Scott and Crossman 1973**
MAFMC 1998b	**Steimle et al. 1999a**
MAFMC 1998c	**Steimle et al. 1999b**
MAFMC 1998d	**Steimle et al. 1999c**
Malone 1977	**Steimle et al. 1999d**
NEFMC 1998	**Steimle et al. 1999e**
NEFMC 1998a	**Tom Hoff, MAFMC, pers. comm., 2001**
NJDEP 1984	**USC 1853(a) (7)**
NMFS 1999a	**USFWS 1997**
NMFS 1999a	**Woodhead 1988**

Response:

Electronic copies of the literature cited have been provided in the "Requested References" File accompanying this data response submittal with these exceptions:

1) Byron Young, NYSDEC, pers. comm. 2001 and Tom Hoff, MAFMC, pers comm., 2001 were discussions in meetings or personal telephone conversations for which meeting minutes and/or telephone records are not available.

2) Casey et al. 1987 and Scott and Crossman 1973 are books. Copyright laws prohibit copying entire books. The title pages and tables of contents are provided electronically.

3) MAFMC 1998b, 1998c, and 1998d are amendments to various fishery management plans that are not available online. The most recent versions of the Fishery Management Plans for these species are included electronically.

4) Woodhead 1988 has not been located. A report called "Woodhead, P.M.J., F.J. Rohlf and M.A. O'Hare. 1992. The Structure of the Fish Community and Distribution of Major Species in the Lower Hudson Estuary and New York Harbor. A Final Report to the Hudson River Foundation" that builds on the information presented in Woodhead 1988 has been provided electronically.

USCG Comment #43:

Topic Report 3 includes a discussion of potential ship strikes on marine mammals in the New York Bight APEX area, but it does not discuss ship tracks approaching the area. Please provide an assessment of potential ship tracks for vessels approaching and departing the Port to determine if areas of marine mammal concentration, especially essential habitat for endangered right whales, will be traversed by incoming or out going LNGCs to determine the potential for impacts outside of the immediate Project area.

Response:

LNG traffic routes from the supply source, into and through American waters, outside those described in Volume Two, Part One, Exhibit N – Marine Vessel Traffic Patterns of the Deepwater Port License Application (May 2007) are currently unknown. Marine mammal occurrence will only be discussed for the ship tracks in the immediate vicinity (within a 20 mile radius) of the Project. The proposed Project site is not near any North Atlantic right whale critical habitat areas. There are currently six major habitat areas for North Atlantic right whales: coastal waters off the southeastern United States, the Great South Channel, Georges Bank/Gulf of Maine, Cape Cod and Massachusetts Bay, the Bay of Fundy, and the Scotian Shelf (Waring et al. 2007) as seen in Figure 43-1 in Attachment 43-1. North Atlantic right whales are highly mobile, and movements within and between habitats may be more extensive than previously known (Mate et al. 1997).

In August 2008, NMFS completed the Final Environmental Impact Statement to Implement Vessel Operational Measures to Reduce Ship Strikes to North Atlantic Right Whales, which includes six proposed alternatives. No regulations have been promulgated based on these measures. Alternative Six was identified as the preferred alternative. There are no North Atlantic right whale critical habitats or conservation areas in the mid-Atlantic Region (defined in this case as Block Island to the mid Georgia coast), the waters off New York or New Jersey, or the Project area. The closest critical habitat to the Project area is in the Northeast Region, in the Great South Channel off Massachusetts (number 5 in Figure 43-1 in Attachment 43-1). Along the Atlantic coast, Alternative Six proposes eight Seasonal Management Areas (SMAs) (Figure 43-2 in Attachment 43-1) within the following Regions:

- Northeast: in Cape Cod Bay, off Race Point, Massachusetts, Great South Channel,
- Mid-Atlantic: New York/New Jersey Harbor, Delaware Bay, Chesapeake Bay, Morehead City,
- Mid-Atlantic/Southeast: a continuous SMA from Wilmington NC to Jacksonville FL as well as recommended routes (NMFS 2008).

SMAs are predetermined within which seasonal speed restrictions are recommended, and, in some cases, ship traffic routes are recommended. Except for the Cape Cod Bay SMA, Race Point SMA, and Great South Channel SMA, the SMAs are established areas within 20 NM of the coastline. The Cape Cod Bay SMA encompasses the entire Cape Cod Bay, including the Cape Cod Bay critical habitat and the area directly west of the critical habitat to the shoreline. The Race Point SMA is approximately 16 miles east of Boston, and the Great South Channel SMA is approximately eight miles east of Cape Cod. Within the Northeast Region, adherence to SMA recommendations is voluntary. There are no mandatory speed restrictions (NMFS 2008).

Nursery areas and possible mating grounds for North Atlantic right whale are in the shallow, coastal waters of New England (Waring et al 2007). Calving takes place in southeastern U.S. waters from December through March, with a peak between mid-December and early January. From 1984 to 2005 within the shipping routes approaching and departing from the Project area, 24 right whales (from 16 separate sightings ranging from one to four whales per sighting) were sighted (Figure 43-3 in Attachment 43-1) (Right Whale Consortium 2005). The number of whales sighted from 1984 to 2005

were relatively consistent over time, with a slight increase in recent years (1984 =1, 1985 =3, 1999 =3, 2001 =3, 2002 =3, 2004 =7, and 2005 =4) (Right Whale Consortium 2005). The whales were seen in February, March, April, June, August, September, and November (Right Whale Consortium 2005). One of the whales in February was feeding, and two whales had calves (one in March and one in April, Right Whale Consortium 2005).

Right Whale Consortium data should be considered snapshots of the whales' presence in the Project area, but they provide an indication of right whale movements through the New York Bight. These data show that North Atlantic right whales occur within the immediate Project area in relatively low numbers throughout much of the year. The combination of relatively low occurrence, the fact that the shipping routes (within a 20 mi radius of the Project) are not within critical habitat and the presence of the New York/New Jersey SMA (with reduced vessel speeds to 10 km when right whales are present), suggests that the risk of ship strike is relatively low.

References:

Mate, B.R., S.L. Nieukirk, and S.D. Kraus. 1997. Satellite-monitored movements of the northern right whale. J. Wildlife Manage. 61(4): 1393-1405.

NMFS 2008. Final Environmental Impact Statement to Implement Vessel Operational Measures to Reduce Ship Strikes to North Atlantic Right Whales. 850 pp.

Ward-Geiger, L.I., G.K. Silber, R.D. Baumstark, and T.L. Pulfer. 2005. Characterization of Ship Traffic in Right Whale Critical Habitat. Coastal Management 33: 263-278.

Waring, G.T., E. Josephson, C.P. Fairfield-Walsh, K. Maze-Foley, editors. 2007. U.S. Atlantic and Gulf of Mexico Marine Mammal Stock Assessments- 2007. NOAA Technical Memo NMFS NE 205; 415 pp.

Attachment 43-1

- Figure 43-1 North Atlantic Right Whale Critical Habitats (Ward-Geiger et al. 2005).
- Figure 43-2 Location of Seasonal Management Areas (Hatched Areas) Proposed Under Preferred Alternative, NMFS 2008.
- Figure 43-3 North Atlantic Right Whales (Circles) Sighted from 1984 to 2005 (Right Whale Consortium 2005) in the Potential Shipping Routes Approaching and Departing (Exhibit N of the Deepwater Port Application 2007) from the Project Area (square).

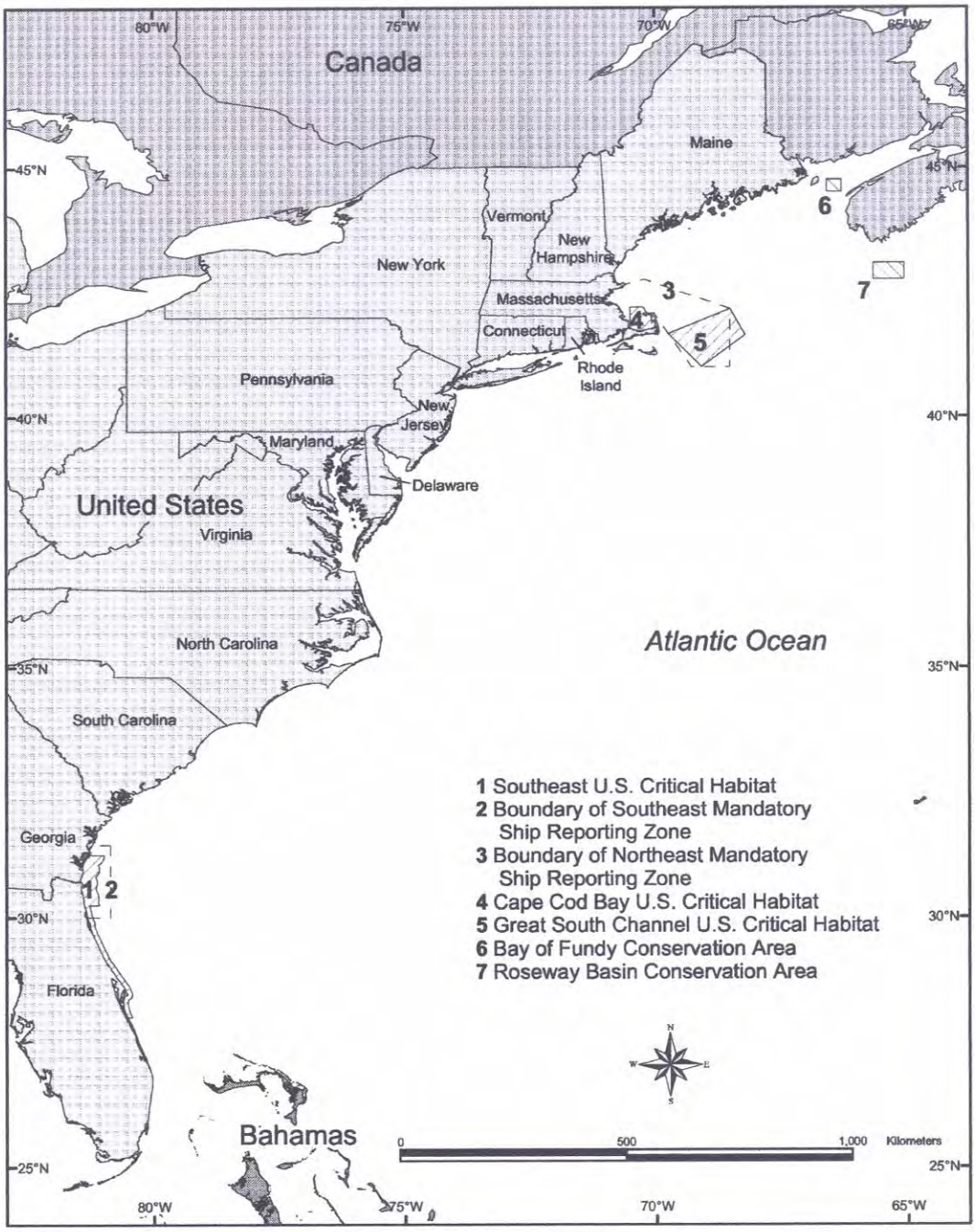

Figure 43-1. North Atlantic right whale critical habitats (Ward-Geiger et al. 2005).