APPENDIX B.9

JCEP PSD Air Quality Permit Application
(Includes Air Quality Modeling Protocol)

Jordan Cove Energy Project, L.P.

Multisource Air Quality Modeling Protocol

Prepared for

Oregon Department of Environmental Quality

Prepared by

TRC Environmental
Lyndhurst, NJ

April 2013

2.0 PROJECT DESCRIPTION

2.1 Facility Conceptual Design

Jordan Cove Energy Project, L.P. is proposing to construct and operate a liquefied natural gas (LNG) export terminal in Coos Bay County, Oregon. The facility is identified as the JCEP LNG Terminal Project and will consist of equipment to receive, liquefy, temporarily store, and send out up to approximately six million metric tons per annum (MMTPA) of LNG. The Project will include the following equipment:

- Four liquefaction trains, each with the capacity of 1.5 MMTPA;
- Two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 billion SCF/day;
- Refrigerant storage and resupply system;
- Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process; and
- The South Dunes Power Plant, a nominal 420 megawatt (MW) natural gas fired combined-cycle electric power plant for the purpose of powering the natural gas liquefaction process systems.

2.2 Equipment/Fuels

The project will include six General Electric (GE) LM6000 PG Combustion Turbines that will utilize pipeline natural gas (sulfur in fuel is 1.00 grains/100 SCF) and which will be equipped with natural gas-fired duct burners for supplementary firing and two steam turbine generators (STGs). By using the waste heat from the combustion turbine to produce steam and generate additional electricity, the Facility will operate with a higher thermal efficiency than many other electricity generating facilities. Supporting ancillary equipment will include two emergency diesel generators (one at the liquefaction site and one at the South Dunes Station) and five emergency diesel fire pumps to provide on-site fire-fighting capability (four at the liquefaction facility and one at the South Dunes Station).

Emissions from the six combined cycle units will be controlled by the use of dry low-NO_x burner technology and SCR for NO_x control, an oxidation catalyst for CO and VOC control, and the use of clean low-sulfur fuels only (i.e., natural gas) to minimize emissions of SO_2, PM/PM-10/PM-2.5, and H_2SO_4. Exhaust gases from the combined cycle units after emission controls will be dispersed to the atmosphere via individual stacks. Steam from the steam turbine will be sent to a condenser where it will be cooled to a liquid state and returned to the heat recovery steam generator (HRSG). Waste heat from the condenser will be dissipated through the air cooled condensers.

In addition to the South Dunes Power Station, the LNG Liquefaction Project will have a number of fugitive VOC emission sources from piping/flanges/valves from both land-based and vessel based sources. The four LNG liquefaction trains will be electric and thus, only fugitive VOC emissions are expected from that equipment.

While combustion emissions from the LNG vessels during hoteling, berthing, deberthing, and transit are expected, these activities are exempt from ODEQ and PSD permitting requirements as they are not considered direct emissions from the Facility. The power to provide for the pumps to load the LNG from the liquefaction facility will be provided by the South Dunes Power Plant and thus, there are no direct combustion emissions from the LNG vessels during the loading process that would be subject to ACDP and PSD review.

The incoming pipeline gas will be treated in facilities located on the South Dunes Power Plant site. The gas conditioning trains condition the incoming pipeline gas prior to liquefaction, storage, and transport, by removing substances that would freeze during the liquefaction process, namely carbon dioxide (CO_2) and water. Mercury is also removed to prevent corrosion in downstream equipment. Hydrogen sulfide and mercaptans are removed using a scavenging system.

The gas conditioning trains consist of two parallel trains, each containing two systems in series: a scavenger system to reduce hydrogen sulfide and mercaptans, a CO_2 removal process which utilizes a primary amine to absorb CO_2, followed by a dehydration system which uses two distinct solid adsorbents to remove water and mercury from the feed gas. Each train will process approximately 460 MMscf/day of natural gas. Acid gas from the Amine Stripper will be sent to a thermal oxidizer in order to oxidize sulfur components. Each thermal oxidizer is assumed to have a 96% reliability. In the unlikely event of thermal oxidizer downtime, the waste gas will vent to the atmosphere. Air emissions from the amine and dehydration systems are not expected.

Two ground flares are included in the Project design. One flare is included to handle gas relieved during emergency upset conditions caused by events including but not limited to: extended power outages, extended emergency shutdown events, and unexpected loss of vapor handling equipment during LNG ship loading with the LNG Storage Tank operating near maximum normal operating pressure. A second ground flare will be used in emergency situations to relieve and protect equipment in the Gas Conditioning portion of the plant. Low pressure flare headers will be continuously purged with fuel gas. A small pilot (42,500 Btu/hr) on each flare with electronic ignition will be continuously operated.

2.3 Operation

The combined cycle units will be operated to follow electrical demand (i.e., dispatch mode) of the liquefaction facility, but will be designed and permitted to operate on a continuous basis. The combined cycle units typically will not operate at steady-state below 50% load and the duct burner will only operate at full load conditions for the combustion turbines. Therefore, the HRSG steam production will follow the combustion turbine loads and higher HRSG steam output will only occur when duct firing is employed during combustion turbine full load operation.

The thermal oxidizers are expected to operate continuously while the gas conditioning system is in operation. In the unlikely event that a thermal oxidizer is down, the waste gas will vent to the atmosphere.

Figure 2-1 presents the Jordan Cove Energy Project, L.P general site plan on an aerial map showing locations of major facility processing areas and equipment. See Figures 5-1 and 5-2 for detailed general arrangement drawings of the South Dunes area and the LNG liquefaction and storage area. Figures 2-2 through 2-4 present process flow diagrams for the major Facility components.

2.4 Source Emission Parameters

Emissions of air contaminants from the proposed Project have been estimated based upon expected vendor emission guarantees, control analysis results, emission factors presented in the U.S. EPA publication AP-42, mass balance calculations, and engineering estimates. Emission calculations used to develop the emission estimates for the proposed equipment are included in this application as Appendix B.

2.4.1 Emissions from the Combined Cycle Units

Emissions from the combined cycle units will include criteria pollutants, non-criteria pollutants, and hazardous air pollutants (HAPs). Short-term and annual emission rates of these pollutants from the combined cycle units are described below.

2.4.1.1 Criteria Pollutants

Combustion turbine performance and emissions are affected by ambient temperature, fuel consumption, power output and fuel type. Proposed emission rates and exhaust characteristics for the combined cycle units are provided in Appendix B. Exhaust and emission parameters are presented for the combustion turbine firing natural gas at three ambient temperatures (20 degrees Fahrenheit, 59 degrees Fahrenheit, and 90 degrees Fahrenheit) and three loads (50%, 75%, and 100%). In addition, emission rates and stack parameters are presented for duct firing during natural gas operation at 100% load. A total of 12 total combustion turbine steady-state operating scenarios are presented.

Criteria pollutant potential emission rates from the combined cycle units are based on vendor emissions data.

2.4.1.2 Greenhouse Gases

For PSD purposes, greenhouse gases (GHGs) are a single air pollutant defined as the aggregate group of the following six gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF_6). CO_2, N_2O and CH_4 are the only pollutants of concern for the combustion turbine units. Potential emissions of CO_2 are based on vendor emissions data. CH_4 and N_2O emissions from the proposed combined cycle units are based on 40 CFR Part 98 emission factors.

2.4.1.3 HAPs

Appendix B presents a summary table of potential emissions of HAPs from the proposed combined cycle units based on U.S. EPA's AP-42 emission factor guidance document. Because the AP-42 formaldehyde emission factor is based on old testing data with limited data points that are not representative of the proposed units, formaldehyde emissions from the combustion turbines while firing natural gas are based upon the California Air Resource Board (CARB) emission inventory that is more representative of the type of high-efficiency dry low-NOx units specified for this project.

2.4.1.4 Other Pollutants

Sulfuric acid mist (H_2SO_4) and ammonia (NH_3) emissions are based on vendor emission estimates.

2.4.2 Emergency Diesel Engines Emissions

JCEP is proposing to use seven (7) diesel internal combustion engines for the emergency generators and back-up fire pumps ranging in size from 400 hp to 3,350 hp. Short-term potential emission rates for each engine are provided based on a combination of potential equipment vendor design data and fuel sulfur content (15 ppm Sulfur oil). HAP emissions from the diesel engines are based on U.S. EPA's AP-42 Emission Factor Guidance Document. GHG emissions are based on 40 CFR Part 98 emission factors. Due to the limited operation of these sources, annual PTE emissions are calculated using the maximum hourly emission rate and 200 hours per year operation per engine. Please see Appendix B for potential emission calculation details.

2.4.3 Thermal Oxidizer Emissions

The Project will consist of two thermal oxidizers (one for each train) to control emissions from the amine treating system and the molecular sieve dehydrators. The thermal oxidizers have a destruction efficiency of greater than 99.5 percent for H_2S, VOC and HC. Emissions from the thermal oxidizers were based on total annual vendor emission estimates. The thermal oxidizers are expected to have a reliability of at least 96%. In the unlikely event that a thermal oxidizer is down, the waste gas will be vented to the atmosphere.

2.4.4 Ground Flare Pilot/Purge Emissions

The ground flares may be used during the following situations:

- Initial cool down of the facility;
- Extended power outage;
- Extended emergency shutdown events;
- Unexpected loss of vapor handling equipment during LNG Ship loading with the LNG storage tank operating near maximum normal operating pressure; and
- Emergency situations to relieve and protect equipment in the Gas Conditioning portion of the plant.

The low pressure flare headers are continuously purged with fuel gas. A small natural gas pilot (42,500 Btu/hr) on each flare with electronic ignition will be continuously operated. The flare pilots have a combustion efficiency of greater than 99 percent.

CO_2, methane, ethane and propane emissions are based on vendor emission estimates. NO_x and CO emissions are calculated using emission factors from TCEQ's "Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers" (October 2000).

2.4.5 Equipment Leak Fugitive Emissions

Fugitive emissions result from leaking process components such as valves and flanges, from LNG storage tank overpressure venting and pressure relief valves and from the LNG loading arms during marine vessel loading. These emissions mainly consist of methane and VOC content of the natural gas. Emissions from fugitive equipment leaks are calculated using fugitive component counts for the proposed equipment at the proposed Plant and emission factors for each component type taken from EPA's "Protocol for Equipment Leak Emission Estimate" (1995).

2.4.6 Facility Total Potential Annual Emissions

Total potential annual emissions for the proposed Project are presented in Table 2-1. Annual emission values in Table 2-1 represent total PTE from all proposed sources and were based on the following worst-case operating scenarios:

- Year-round (8,760 hours), full load operation of each combustion turbine (at 59°F annual average ambient temperature);
- The equivalent of 4,000 hours of duct firing at maximum design firing rate for each combustion turbine;
- A total of 275 annual combined cycle shutdown/startup events per turbine (30 cold starts, 85 warm starts and 160 hot starts);
- 200 hours per year of operation of the emergency diesel generators and 200 hours per year of operation of the diesel fire pump engines;
- Year-round (8,760 hours) operation of the thermal oxidizers and ground flares; and.
- 4% annual operation of the thermal incinerator vents.

Fugitive emissions from the LNG storage tanks, marine vessel loading operations and process equipment leaks were also included in the Project's annual potential to emit.

Table 2-1: Summary of Project Criteria Pollutant and Total HAPs Annual Emissions

Source	Potential Annual Emissions (tons/year)						
	NO_X	CO	VOC	SO_2	PM/PM-10/ PM-2.5	GHG [CO2e]	HAPS[a]
Combined Cycle Units[b]	106.32	129.97	74.78	46.1	180.42	1,695,525	--
Start-Up/Shutdown Emissions[c]	47.77	2.31	0.0	--	0.0	--	--
South Dunes Fire Pump[d]	0.24	0.27	0.02	0.00041	0.01	44	--
Liquefaction Area Fire Pumps[d]	1.71	1.87	0.14	0.0029	0.09	307	--
Emergency Generators[d]	6.56	3.84	0.53	0.0068	0.22	1,471	
Thermal Oxidizers/Vents[e]	58.3	17.5	1.61	17.4	1.15	464,465	--
Flares[e]	0.14	0.28	1.12	0.01	0.0022	555.4	--
Fugitives[f]	--	--	131.05	--	--	3,549	--
Facility-Wide Total	**221.0**	**156.1**	**209.3**	**63.5**	**181.9**	**2,165,917**	**2.5/8.9**

Notes:

[a] The potential HAP emission calculations presented in Appendix B result in total HAP emissions less than 25 tons/yr. Additionally, potential annual emissions of the maximum individual HAP are less than 10 tons/yr.

[b] Potential annual emissions from the combined cycle units assume the equivalent of 8,760 hr/yr of combustion turbine operation and 4,000 hr/yr of duct firing.

[c] Combined cycle unit start-up/shutdown emissions are added to the baseline steady-state PTE values if the total start-up/shutdown emissions are more than the steady-state full-load equivalent during the period of unit off-line downtime and duration of the start-up (and previous shutdown). For start-up/shutdown emissions noted above as "—" for certain pollutants, the start-up/shutdown emissions addition to the baseline steady-state PTE is not applicable since mass emissions of these pollutants are fuel input based (lb/MMBtu) and the full-load, steady-state basis represents the worst-case scenario for PTE emission

[d] Potential annual emissions from the emergency diesel generators and fire pumps assume 200 hours per year of operation.

[e] Potential emissions from the thermal oxidizers and ground flares assume year-round (8,760 hours) operation. Annual emissions from the TO vents assume 4% annual operation.

[f] Fugitive emissions include emissions from the LNG storage tanks, marine vessel loading operations and process equipment leaks.

Figure 2-1: Locations of Major Facility Equipment and Processing Areas

Figure 2-2: Process Flow Diagram for Gas Conditioning System

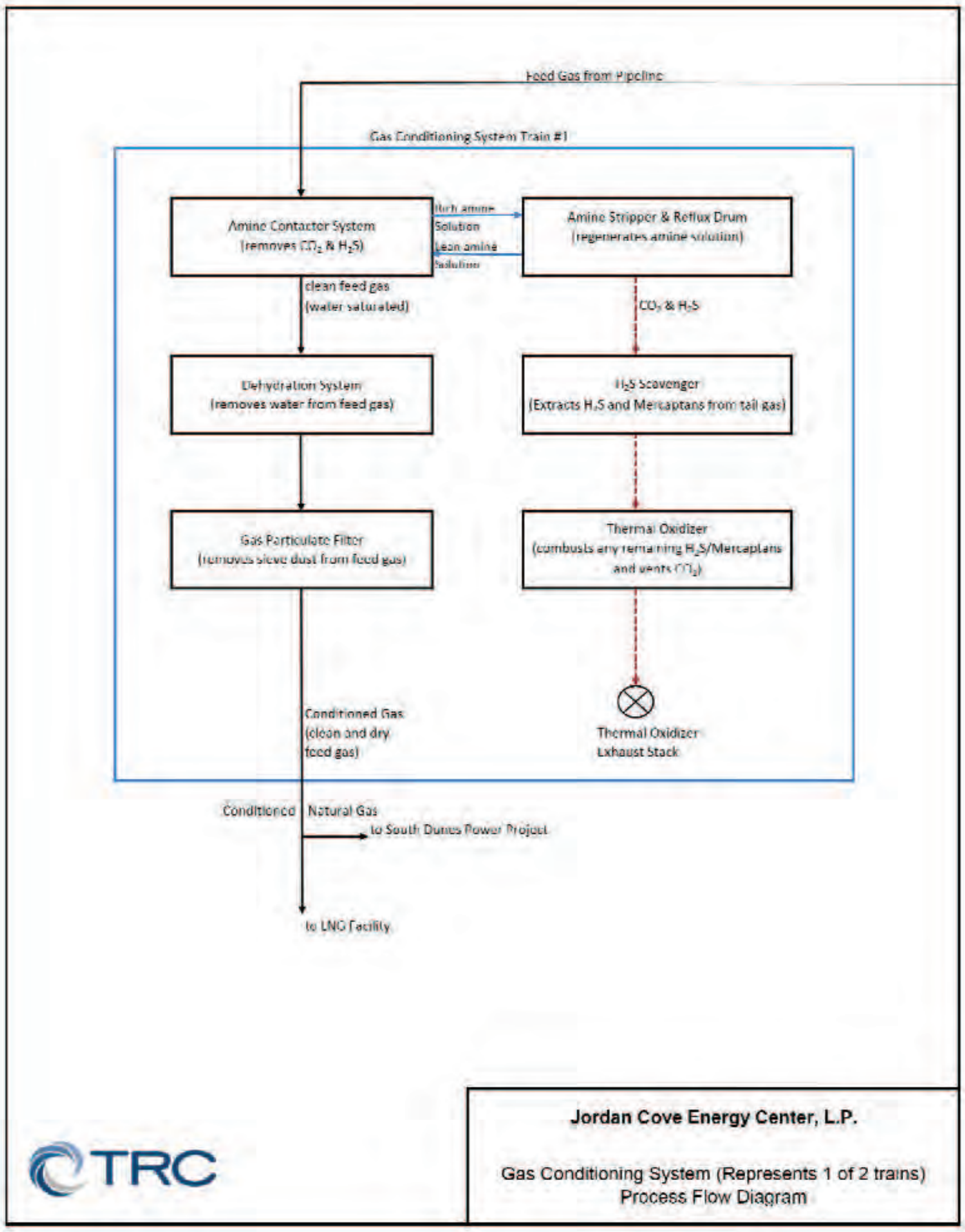

Figure 2-3: Process Flow Diagram for South Dunes Power Plant

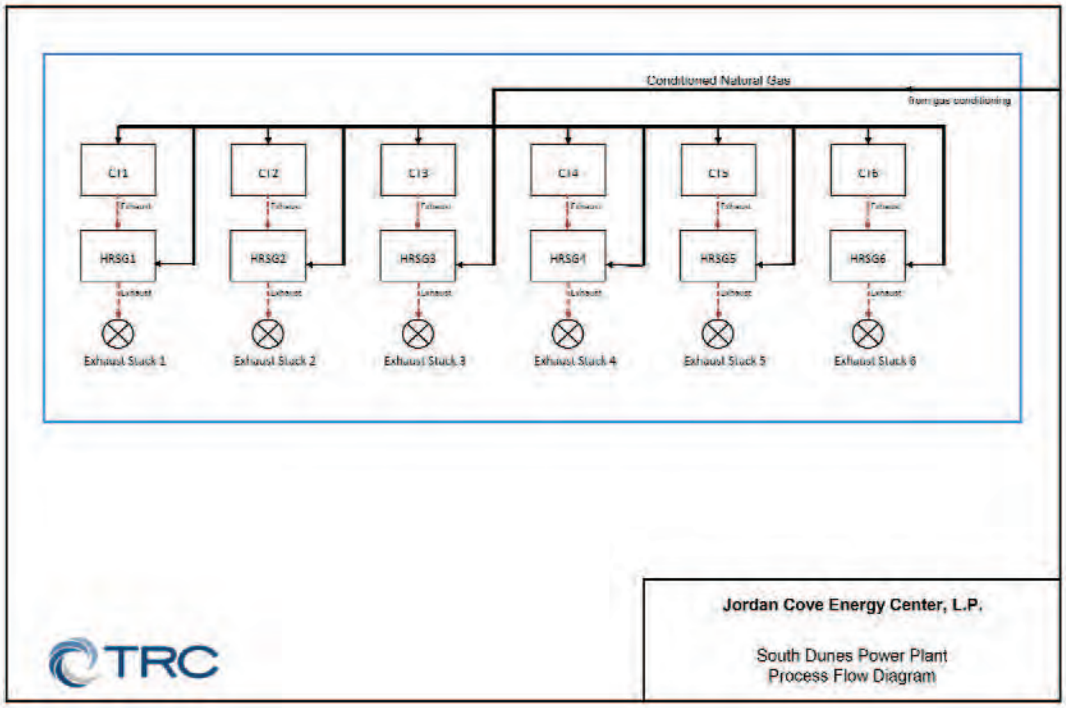

Figure 2-4: Process Flow Diagram for Liquefaction Area