Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for Nuevo Midstream, LLC, Reeves County, Texas Permit Number: PSD-TX-1392-GHG

October 2014

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On January 22, 2014, Nuevo Midstream, LLC (Nuevo) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions to authorize a major expansion at its existing permitted facility, the Ramsey Gas Plant. In connection with this same proposed modification, Nuevo submitted an application for a PSD permit for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on January 21, 2014. Nuevo currently owns and operates the Ramsey Gas Plant, a natural gas processing facility located in Orla, Reeves County, Texas. The existing facility is comprised of the original plant (Ramsey I Plant), the 100 million standard cubic feet per day (MMSCF/D) Ramsey II Plant, the 200 MMSCF/D Ramsey III Plant and the associated 475-gallon per minute (gpm) and 1,300-gpm amine units. Nuevo is proposing to build three additional cryogenic plants (Ramsey IV, Ramsey V, and, Ramsey VI), each with a 200 MMSCF/D capacity, and associated 1,000-gpm Amine I plant and 1,000-gpm Amine II Plant. After reviewing the application EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction at the Ramsey Gas Plant.

This SOB documents the information and analysis EPA used to support the decision EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Nuevo's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by Nuevo, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

Nuevo Midstream, LLC – Ramsey Gas Plant
1221 Lamar, Suite 1100
Houston, TX 77010

Facility Physical Address:
231 CR 452
Orla, TX 79770

Facility Mailing Address:
P.O. Box 9
Malaga, NM 88263

Contact:
Mr. Dwight Serrett
Vice President Operations
Nuevo Midstream, LLC
(713) 337-6510

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs 75 FR 25178 (promulgating 40 CFR § 52.2305)

The GHG PSD Permitting Authority for the State of Texas is:
EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Ms. Nevine Salem
Air Permitting Section (6PD-R)
(214) 665-7222

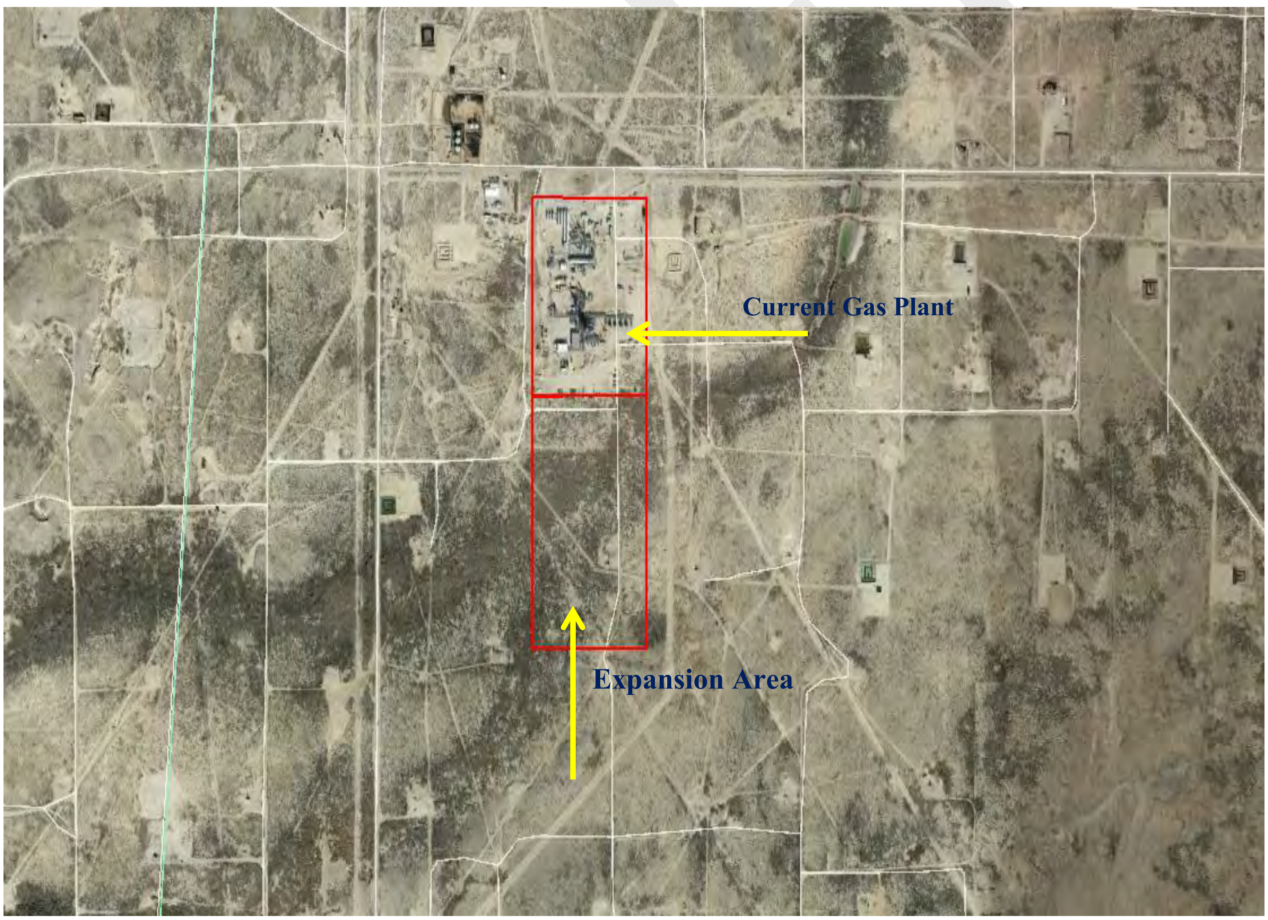
IV. Facility Location

The Ramsey Gas Plant is located in Reeves County, Texas. The geographic coordinates for this facility area are as follows:

Latitude: 31° 55' 34.72"
Longitude: -104° 01' 19.61"

Reeves County is rural with no large town or any significant manufacturing industry in the immediate area. Most of the county, including the area around the Ramsey Gas Plant, is a broad gently-sloping plain, with sparse grasses, scrub brush, cacti and mesquite. The nearest Class I area located within 100 kilometers (62 miles) or less are Guadalupe Mountain National Park, TX and NM, and Carlsbad Caverns National Park, NM.

Below, Figure-1 illustrates the facility location for this draft permit.



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). *Utility Air Regulatory Group (UARG) v. Environmental Protection Agency (EPA) (No. 12-1146).* The Supreme Court said that the EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a Prevention of Significant Deterioration (PSD) or title V permit. However, Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the District of Columbia Circuit Court of Appeals, the EPA is proposing to issue this permit consistent with EPA's understanding of the Court's decision.

Emissions information contained in the PSD permit application submitted by Nuevo to TCEQ shows that the Ramsey Gas Plant expansion project is a major source because the Ramsey expansion project has the potential to emit 324.34 tpy of NO_x, which is a non-GHG regulated pollutant. In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined the project is subject to PSD review for the following conventional regulated NSR pollutants: VOC, NO_x, CO, PM_{10}, $PM_{2.5}$ and SO_2. The applicant also estimates that this same project emits or has the potential to emit 568,067 tpy CO_2e of GHGs, which well exceeds the 75,000 ton per year CO_2e threshold in EPA regulations. 40 C.F.R § 52.21(49)(iv); *see also, PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at 12-13. Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

Accordingly, this project continues to require a PSD permit that includes limitations on GHG emissions based on application of BACT. The Supreme Court's decision does not materially limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 proposes to follow the policies and practices reflected in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011). For the reasons described in that

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA believes that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow Nuevo to build three additional facilities (Ramsey IV, V, and VI Plants) and associated Amine Plants (Amine I and II Plants). Nuevo Midstream core capabilities include gas gathering, treating and conditioning, compression, and processing. This expansion project will increase the processing capacity of the existing plant with three 200 MMSCF/D cryogenic plants and two 1,000-gpm amine plants, or equivalent, with combined rating being ≤ 2,000 gpm.

Inlet gas will flow into the Ramsey Gas Plant from a low pressure inlet separator and will be compressed and boosted to plant inlet pressure. This gas is combined with the high pressure Avalon, Bone Springs and Wolfcamp inlets. In the proposed amine units, lean amine solution will be fed to the amine contactor to absorb the H_2S and CO_2 (acid gas) in the inlet gas. The rich amine solution from the amine contactor will be flashed in the amine flash drum and routed to the appropriate amine still where the acid gas is stripped from the amine solution with steam generated by heat exchanged with hot oil in the amine re-boilers. The hot oil used to regenerate the amine is heated by hot oil heaters (Emission Point Number(s) (EPNs): H-9 and/or H-11). The gas flashed in the amine flash drum is recycled to the suction of the low pressure inlet compressors and is not an emissions source. Amine Plants I and II will be associated with amine still vent A-4 and regenerative thermal oxidizer RTO-4 and amine still vent A-5 and regenerative thermal oxidizer RTO-5, respectively. A percentage of the acid gas from the amine still vents (EPNs: A-4 and A-5) will be captured and routed to a pipeline for Carbon Capture and Sequestration purposes and the remaining acid gas from the amine still vents will be routed to the regenerative thermal oxidizer (EPNs: RTO-4 and RTO-5).

The sweet gas from the amine units is routed to the molecular sieve dehydrators. From the molecular sieve dehydrators the gas is routed to the respective cryogenic plants. The molecular sieve regeneration and process heat for the plants will be furnished by regenerator heaters (EPNs: H-8, H-10, and H-12)

Propane refrigeration is required for inlet gas chilling and the single column overhead recycle process is contained in a closed-loop process. Liquid propane is level controlled into the economizer where the non-condensable gases flash, cooling the propane to 55 ^{o}F. The vapor from the economizer is returned to the refrigerant compressor inter-stage, reducing the compression horsepower required. The liquid propane in the economizer is routed to the chillers in the cryogenic plant, vaporized, and returned to the compressors where the process is repeated inside the closed-loop.

The Y-grade liquid product normally flows from the cryogenic section to the product surge tank prior to being shipped off-site by pipeline. If necessary, the facility also has the ability to "deethanize" the liquid product in the demethanizer and store it in pressurized tanks prior to being shipped offsite by truck. The pressurized product loading operation is a closed system with no emissions.

The clean dry gas goes through multiple heat exchangers where the temperature is dropped and the ethane and heavier components of the gas stream are liquefied. The remaining gas and liquids mixture is sent to the demethanizer where the methane gas is stripped from the ethane rich liquid by warm vapors as it flows across the trays and through the packed sections of the demethanizer tower. The heat required for the distillation is supplied by exchange with the warm inlet gas. If deethanization is required, the facility has the ability to "deethanize" the liquid product and store it in pressurized tanks prior to being shipped offsite by trucks, the pressurized product loading operation is a closed system with no emission.

The residue gas from each plant will be compressed by five (5) Caterpillar G3612 LE (or equivalent) natural gas-fired engine driven compressors. Ramsey IV Plant will have the following EPNs: COMP-15, COMP-16, COMP-17, COMP-18 and COMP-19. Ramsey V Plant will have the following EPNs: COMP-20, COMP-21, COMP-22, COMP-23 and COMP-24. Ramsey VI Plant will have the following EPNs: COMP-25, COMP-26, COMP-27, COMP-28 and COMP-29.

Very low carbon density plant residue gas, equivalent to pipeline quality natural gas will be used for fuel under normal circumstances.

VII. General Format of the BACT Analysis

The BACT analyses were conducted in accordance with EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011), which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below:

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;

(4) Evaluate the most effective controls and document the results; and
(5) Select BACT

As part of the PSD review, Nuevo provided in the GHG permit application a 5-step top-down BACT analysis for the units covered by this permit. In setting forth the various BACT limits for this proposed permit EPA has reviewed Nuevo's BACT analysis, portions of which have been incorporated into this Statement of Basis, and we also conducted our own analysis, as summarized below.

VIII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHG associated with the project is from combustion sources (e.g. regenerative thermal oxidizers, internal combustion compressor engines, and hot oil and regeneration heaters). The proposed Nuevo modification GHG emissions total approximately 568,067 tpy CO_2e (including emissions from Maintenance, Start up, and Shut down (MSS) activities). The stationary combustion sources primarily emit CO_2, N_2O, and CH_4 as greenhouse gas emissions. The following devices are subject to this GHG PSD permit:

- Gas Fired Internal Combustion Compressor Engines (EPNs: COMP-15, COMP-16, COMP-17, COMP-18, COMP-19, COMP-20, COMP-21, COMP-22, COMP-23, COMP-24, COMP-25, COMP-26, COMP-27,COMP-28, and COMP-29)
- Hot Oil Heaters (EPNs: H-9 and H-11)
- Regeneration Heaters (EPNs: H-8, H-10, and H-12)
- Amine Still Vents (EPNs: A-4 and A-5)
- Regenerative Thermal Oxidizers (EPNs: RTO-4 and RTO-5)
- Process Fugitives (EPNs: FUG4, FUG5, and FUG6)

IX. Gas-Fired Internal Combustion Compressor Engines (EPNs: COMP-15, COMP-16, COMP-17, COMP-18, COMP-19, COMP-20, COMP-21, COMP-22, COMP-23, COMP-24, COMP-25, COMP-26, COMP-27, COMP-28, and COMP-29

Each cryogenic plant at the Ramsey Gas Plant will have 5 natural gas-fired compressor engines. The residue gas from each plant will be compressed by five (5) Caterpillar G3612 LE (or equivalent) natural gas-fired engine driven compressors. Ramsey IV Plant will have the following EPNs: COMP-15, COMP-16, COMP-17, COMP-18, and COMP-19. Ramsey V Plant will have the following EPNs: COMP-20, COMP-21, COMP-22, COMP-23, and COMP-24. Ramsey VI Plant will have the following EPNs: COMP-25, COMP-26, COMP-27, COMP-28, and COMP-29.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Sequestration (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites' affected combustion units.
- *Fuel Selection* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Low carbon density fuel selection is a control option that could be considered a lower emitting process.
- *Good Combustion, Operations, and Maintenance Practices* – Techniques include operator practices, maintenance knowledge, and maintenance practices to control the formation of GHG emissions.
- *Air/Fuel Ratio Controllers* – Oxygen monitors and intake flow monitors can be used to optimize the fuel/air mixture and limit excess air and reduce the amount of energy required to heat the steam and, therefore, reduce the CO_2e emissions. The heaters' air and fuel valves will be mechanically linked to maintain the proper air to fuel ratio.
- *Efficient Engine Design* – Large natural gas fired engines utilize either rich burn or learn burn technology to attain required low criteria pollutant emission levels. Rich burn technology controls combustion temperature by maintaining excess fuel in the combustion zone, and is an inherently inefficient combustion process. Lean burn technology, on the other hand, utilizes excess air in the combustion zone. The excess air absorbs heat during combustion reducing the combustion temperature and pressure and greatly reducing levels of criteria pollutants. Lean burn technology provides longer component life and excellent fuel efficiency.
- *Electric Powered Compression* – It is technically possible to install large electric motors to power compressors, instead of those powered by gas.

Step 2 – Elimination of Technically Infeasible Alternatives

EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review - *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), pg. 33. We are unaware of CCS being demonstrated in practice on natural-gas fired compressor engines of the type to be used at this facility. While CO_2 capture technologies may be commercially available generally, we believe that there is insufficient information at this time to conclude that CO_2 capture is applicable to the proposed natural gas-fired internal combustion compressor engines for this facility due to the low volume and low concentration of CO_2 streams resulting from the engines. In addition, to process the low purity and concentration CO_2 streams from natural gas-fired compressor engines for CCS, the Ramsey Plant would need to have additional auxiliary power and associated equipment, and the space necessary for such equipment exceeds the physical construction footprint available for the proposed addition to the plant. Therefore, EPA has determined at that CCS is technically infeasible for the gas-fired internal combustion compressor engines to be used at this facility and can be eliminated as BACT.

Also, electric powered compression can't be utilized at the Ramsey Plant, since there is insufficient grid capacity for the number of electrical engines that would need to be operated at this facility. Large compressors like those necessary at the facility require a high-voltage, high amperage electric supply that is not available at the plant site.

In regards to the remaining control options, EPA finds that all are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

With elimination of CCS and electric powered compression as a control options for the compressor engines, the following remain as technically feasible control options for minimizing GHG emissions from the engines. Nuevo proposes to implement all of the following control options for the internal combustion compressor engines.

Control Technology	***Estimated GHG % Reduction***
Fuel Selection	28%
Good Combustion, Operations, and Maintenance Practices	1 - 10%
Air/Fuel Ratio Controllers	1 - 10%
Efficient Engine Design	1 - 10%

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts.

<u>Fuel Selection</u>

Firing a low carbon fuel reduces the CO_2 production from combustion. Nuevo proposes to use very low carbon density plant residue gas, equivalent to pipeline quality natural gas as fuel. Residue gas is the lowest carbon fuel available for use in the proposed engines. Residue gas, similar to natural gas, is a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Good Combustion, Operations, and Maintenance Practices

Maximizing combustion efficiency can minimize the amount of fuel needed to maintain facility production and so minimize GHG emissions. Proper operations involves providing the proper air-to-fuel ratio, properly designed combustion controls; and proper maintenance of the engines per the manufacturer's specification. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Air/Fuel Ratio Controllers

The engine management system provided by the manufacturer with the engines proposed for the Ramsey Plant expansion integrate speed control, air/fuel ratio control, and ignition/detonation controls so as to maximize combustion efficiency and minimize GHG emissions. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Efficient Engine Design

The engines selected for the Ramsey Plant expansion incorporate energy efficient, low carbon emission lean burn technology. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company, Jackson County Gas Plant Ganado, TX	Compressor Engines (Dual Drive)	Energy Efficiency/ Good Design & Combustion Practices	1,871.7 lb CO_2/MMSCF on a 365-day rolling average	2012	PSD-TX-1264-GHG
Cheniere Corpus Christi Pipeline, Sinton Compressor Station Sinton, TX	Gas Compressors	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT is to maintain a minimum thermal efficiency of 36% on a 12-month rolling average basis. Output based limit of 1.18 lb CO_2/hp-hr	*	PSD-TX-1304-GHG

* GHG Permit has been proposed by EPA but has not yet been issued.

Nuevo will use five (5) Caterpillar G3612LE, or equivalent, internal combustion engines in each plant. EPA proposes that the internal combustion compressor engines will have a BACT output-based limit of 2,061.5 lbs CO_2 /MMSCF for each plant (412.3 lb CO_2 /MMSCF for each engine). This is in the range for other engines listed in the table. The Ramsey engines will be used for compression of natural gas and not for power generation. The ETC Jackson Plant utilized 1,871.7 lb CO_2/MMSCF using dual drive (electrical and gas-fired) engines. The Ramsey engines will be natural gas-fired engines only. As shown above, EPA Region 6 analyzed the BACT limit proposed by the applicant and has determined it is consistent with other BACT determinations for similar units and consequently reasonable estimation of BACT.

The following specific BACT practices are proposed for the Internal Combustion Compressor Engines:

- Fuel Selection
- Good Combustion Practices, Operating, and Maintenance Practices
    - Monitor residence time
    - Monitor temperature
    - Monitor combustion zone turbulence
    - Tune-up of the engines annually or per the manufacturer's specification
- Air/Fuel Ratio Controllers
- Efficient Engine Design

<u>BACT Limits and Compliance</u>

Using the BACT practices above will result in an output based BACT limit for the engines based on the volume of natural gas compressed. The engines shall have a BACT limit based on the CO_2 from the residue gas GVC analysis divided by the measured daily natural gas output from each plant in Million Standard Cubic Feet (MMSCF). Compliance is based on a 365-day rolling average. The output based BACT limit for each engine 412.3 lb CO_2 /MMSCF. Startup and shut down emissions are included in the overall GHG emission limits contained in the permit. Total GHG emissions will be limited to 78,490 TPY CO_2e (based on 12-month rolling average) for five (5) compressor engines combined in each plant.

Compliance with the CO_2 limits for the engines based on metered fuel consumption and using the average high heat value (HHV) calculated according to the requirements at 40 CFR 98.33(a)(2)(ii) for the residue gas, and/or fuel composition and mass balance. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$\mathrm{CO2} = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.1023$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for (High Heat Value) HHV at §98.33(a)(2)(ii)
MW = Annual average molecular weight of gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon
0.001= Conversion of kg to metric tons
1.102311 = Conversion of metric tons to short tons

As an alternative, Nuevo may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input. As the emissions from CO_2 contribute most (greater than 99%) of the overall emissions from the engines, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling basis.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the engines and are considered a *de minimis* level in comparison to the CO_2 emissions.

X. Hot Oil Heaters (EPNs: H-9, H-11) and Regeneration Heaters (EPNs: H-8, H-10, and H-12)

The Hot Oil Heaters EPN H-9 at Ramsey IV Plant, and EPN H-11 at Ramsey VI Plant will be fired with plant residue gas, which is a very low carbon density gas equivalent to pipeline quality natural gas. The Hot Oil Heaters EPNs H-9 and H-11 each will be rated at 60

MMBtu/hr, or equivalent, with the total combined rating for the hot oil heaters limited to 120 MMBtu/hr. The Regeneration Heaters EPN H-8 at Ramsey IV Plant, EPN H-10 at Ramsey V Plant, and EPN H-12 at Ramsey VI will be fired with residue gas and will each be rated at 36 MMBtu/hr, or equivalent, with the total combined rating for the regeneration heaters limited to 108 MMBtu/hr.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Sequestration (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites' affected combustion units.
- *Fuel Selection:* Non-emergency equipment will be firing only low carbon intensity plant residue gas (similar to pipeline quality natural gas) which results in 28% less CO_2 production than fuel oils.
- *Good Combustion Practices:* Techniques include operator practices, maintenance knowledge, and maintenance practices to control the formation of GHGs emissions. Periodic tune-ups will increase the efficiency of the equipment. Maintenance will be performed routinely per vendor recommendations of the facility's maintenance plan, and replacing or servicing components will be performed as needed. Nuevo will tune the heaters once a year for optimal thermal efficiency.
- *Fuel Gas Pre-heating:* Preheating the fuel stream reduces the heating load, increases thermal efficiency, and therefore reduces emission.
- *Combustion Air Controls:* Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Oxygen monitors and intake flow monitors can be used to optimize the fuel/air mixture and limit excess air and reduce the amount of energy required.
- *Efficient Heater Design:* Efficient design improves mixing of fuel and creates more efficient heat transfer.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 for the Hot Oil Heaters and Regeneration Heaters are considered technically feasible for this project, except Fuel Gas Pre-heating and CCS. Preheating fuel has not been demonstrated in practice on the proposed heaters, nor is it available or applicable to heaters of this small size (< 100 MMBtu/hr). Accordingly, preheating fuel gas is technically infeasible for these units.

CO_2 capture technologies, including post-combustion capture, have not been demonstrated in practice on hot oil heaters and regeneration heaters rated at less than 100 MMBtu/hr. While CO_2 capture technologies may be commercially available generally, there is insufficient information at this time to conclude that CO_2 capture is applicable to the proposed hot oil heaters and regeneration heaters of the size proposed for this project. Accordingly, CCS is eliminated as technically infeasible for these units.

In regards to the remaining control options, EPA finds that all are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Control Technology	*Estimated GHG % Reduction*
• Fuel Selection (low carbon density plant residue gas)	28
• Efficient Heater Design	1-10
• Good Combustion Practices	1-10
• Combustion Air Controls	1-3

Fuel selection, efficient heater design, good combustion practices, and combustion air controls are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from the *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, issued by EPA in October 2010.[2]

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Fuel Selection

Firing a low carbon fuel reduces the CO_2 production from combustion. Residue gas is the lowest carbon fuel available for use in the proposed heaters. Residue gas is a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Efficient Heater Design

New heaters can be designed with efficient burners, more efficient heat transfer efficiency to the hot oil and regeneration streams, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

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[2] Available at http://www.epa.gov/nsr/ghgdocs/refineries.pdf

Good Combustion Practices

Good combustion practices include providing the proper air-to-fuel ratio, residence time, temperature and combustion zone turbulence essential to maintain low GHG emissions, operator practices, maintenance knowledge, and proper maintenance and tune-up of the heaters at least annually per the manufacturer's specification. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Combustion Air Controls

Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and for safety reasons. More excess air than needed to achieve these objectives reduces overall heater efficiency. Manual or automated air/fuel ratio control is used to optimize these parameters and maximize the efficiency of the combustion process. Automated controls are considered more efficient than manual controls. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company/ Location	Process Description	BACT Control(s)	BACT Emission Limit/Requirements	Year Issued	Reference
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	Four Natural Gas Processing Plants 4 Hot Oil Heaters (48.5 MMBtu/hr each) 4 Molecular Sieve Heaters (9.7 MMBtu/hr each) 4 Regeneration Heaters (3MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters per plant of 1,102.5 lbs CO_2/MMSCF 365-day average, rolling daily for each plant	2012	PSD-TX-1264-GHG
Targa Gas Processing LLP, Longhorn Gas Plant, TX	1 Hot Oil Heaters (98 MMBtu/hr) 1 Regeneration Heater (12 MMBtu/hr) 1 TED Reboiler (2 MMBtu/hr)	Energy Efficiency/Good Design & Combustion Practices	GHG BACT limit for all heaters is 1,783.23 CO_2 lb/MMSCFD(combined limit for the three units)	2013	PSD-TX-106793-GHG

The BACT determination for all the above-referenced facilities apply to gas processing plants.

The total firing rate for all the heaters in ETC Jackson County Gas Plant is 244.8 MMBtu/hr. ETC Jackson Gas Plant has an output-based BACT limit of 1,102.5 lbs CO_2/MMSCF. The total firing rate for the Targa heaters is 112 MMBtu/hr. Targa Longhorn Gas Processing has an output-based BACT limit of 1,783.23 lbs CO_2/MMSCFD for the three heaters. Nuevo's total firing rate is 228 MMBtu/hr which is approximately equal to ETC's Jackson County Gas Plant and twice that of Targa's Longhorn Gas Plant. Nuevo has proposed an output-based BACT limit of 280.5 lbs CO_2/MMSCF for each hot oil heater and 168.3 lbs CO_2/MMSCF for each regeneration heater in the Ramsey (IV, V, and VI) Plants. The combined output for Nuevo[3] will be 1065.9 lbs CO_2/MMSCFD, which will be more efficient compared to output-based BACT for ETC and Targa heaters listed above. As shown above, EPA Region 6 analyzed the BACT limit proposed by the applicant and has determined it is consistent with other BACT determinations for similar units and consequently reasonable estimation of BACT.

The following specific BACT practices are proposed for the heaters:

- *Fuel Selection*– Nuevo will be firing very low carbon density plant residue gas, equivalent to pipeline quality natural gas, as fuel for all on-site combustion equipment in Ramsey IV, V and VI gas plants which results in 28% less CO_2 production than fuel oils.
- *Good Combustion Practices* - The proposed plant design includes specifications for state-of-art heaters include fuel gas monitoring for consumption and temperature monitoring to insure the heaters fire sufficiently to maintain temperature for heat requirement.
- *Efficient Heater Design* – Efficient design improves mixing of the fuel and creates more efficient heat transfer. Nuevo will install new equipment, the proposed heaters will be designed to optimize combustion efficiency.
- *Combustion Air Controls*– Nuevo will use oxygen monitors and intake air flow monitors to optimize the fuel/air mixture and limit excess air and reduce the amount of energy required to heat the stream and, therefore reduce the CO2 emissions.

The following monitoring and work practice requirements proposed by Nuevo will assist in maintaining the BACT efficiency limit and annual efficiency limits for the hot oil and regeneration heaters:

- Use of plant residue gas as fuel
- Installation of insulation where feasible on heater surface

[3] Ramsey IV and VI plants will each have one hot oil heater and one regeneration heater so the combined output for the heaters in Ramsey IV and VI plants will be 897.6 lbs CO_2/MMSCFD. Ramsey V plant will only have one regeneration heater with a BACT output-based limit of 168.3 lbs CO_2/MMSCFD

- Perform annual maintenance as recommended by the manufacturer and maintain records of maintenance activities.
- Clean heater burner tips and convection tubes at a minimum of every 5 years.
- Install a totalizing fuel flow meter (calibrated annually) to continuously monitor fuel usage and record daily fuel consumption.
- Install a non-resettable hour meter to continuously record hours of operation.
- Semiannual analysis of plant residue gas fuel to determine the higher heating value in Btu/scf, molecular weight, and carbon content.
- Install and operate oxygen sensor to allow manual adjustment to optimize fuel/air mixture and limit excess air.
- The oxygen analyzer will continuously monitor oxygen concentrations and provide oxygen concentration data to plant control systems so that the fuel/air mixture can be optimized and excess air limited.

BACT Limits and Compliance:

Using the BACT practices above will result in an output-based BACT limit for the heaters based on the Million Standard Cubic Feet (MMSCF/D) per day of natural gas processed. The two (2) Hot Oil Heaters shall each have a 280.5 lbs CO_2/MMSCFD gas processed BACT limit. The Regeneration Heaters each shall have a 168.3 lbs CO_2/MMSCFD gas processed BACT limit. Compliance will be determined for each limit on a 12-month rolling average.

Both the hot oil and regenerator heaters will be designed to incorporate efficiency features, including insulation to minimize heat loss and heat transfer components that maximize heat recovery while minimizing fuel use. Nuevo will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for all heaters.

Compliance with the CO_2 limits for the heaters is based on metered fuel consumption and using the average high heat value (HHV) calculated according to the requirements at 40 CFR 98.33(a)(2)(ii) for the residue gas, and/or fuel composition and mass balance. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$\mathrm{CO2} = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.1023$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of residue gas (short tons)

Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).

CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for (High Heat Value) HHV at §98.33(a)(2)(ii)
MW = Annual average molecular weight of gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon
0.001= Conversion of kg to metric tons
1.102311 = Conversion of metric tons to short tons

As an alternative, Nuevo may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input. Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the heaters and; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling basis.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emissions are less than 0.01% of the total CO_2e emissions from the engines and are considered a *de minimis* level in comparison to the CO_2 emissions.

XI. Amine Unit Still Vents (EPNs: A-4, A-5)

The two amine units (Amine Plants I and II) at the Ramsey Gas Plant will be used to remove CO_2 in order to meet pipeline specifications for transportation of the natural gas. Because the amine units are designed to remove CO_2 from the inlet gas stream, the generation of CO_2 is inherent to the process, and any reduction of the CO_2 in the inlet stream through process changes would reduce the process efficiency of the facility overall. This would result in a greater CO_2 content in the natural gas that is produced at the plant, which would eventually be emitted when the gas is combusted. The process-based CO_2 emissions emitted from the amine still vents are calculated based on the estimated flow rate and the gas composition of the waste gas.

Step 1 – Identification of Potential Control Technologies for GHGs

The available GHG emission control options for the process emissions include:

- *Carbon Capture and Sequestration (CCS)* – Capture and transfer of CO_2 from the amine still vents.
- *Flare* – the use of a flare can only reduce the CH_4 emissions contained in the stripped amine acid gases. Flare or other VOC controls are required on amine still vents that must meet criteria pollutant BACT. Flares have a destruction efficiency rate (DRE) of 98% for VOCs and 99% for compounds containing no more than 3 carbons and that contain no elements other than carbon and hydrogen, including CH_4.
- *Route gas to the Regenerative Thermal Oxidizer (RTO)* – Another option to reduce the GHGs, specifically CH_4, emitted from amine vents at the Ramsey Plant is to send the stripped amine acid gases to an RTO, which is generally used for control of VOCs emissions. The RTO has a high efficiency for heat recovery. This allows the facility to recover heat from the exhaust stream, reducing the overall heat input of the plant. In general the RTO has a destruction and removal efficiency (DRE) greater than 99% for all VOC and HAP compounds, which is more efficient than a typical flare. In contrast with a flare, which requires the use of supplemental fuel to increase the waste gas heating value as well as a constant pilot, a RTO only uses a minimal amount of natural gas to get up to the optimum temperature for combustion, resulting in lower use of supplemental fuel and lower GHG emissions.
- *Condenser* – A condenser could provide supplemental emissions control. Condensers reduce the temperature of the still column vent vapors on amine unites to condense water and VOCs, including CH_4. The condensed liquids can then be collected for further treatment or disposal. The reduction efficiency of condensers is variable and depends on the type of condenser and composition of the waste gas, ranging from 50-98% of the CH_4 in the waste gas stream.
- *Use of Tank Flash Gas Recovery System* – Flash tanks are used to recycle off-gases formed as the pressure of the rich amine streams drops to remove lighter compounds in the stream. The amine units will be equipped with flash tanks. The off-gases can be recycled back into the plant for reprocessing, instead of venting to the atmosphere or a combustion device. The use of flash tanks increases the effectiveness of other downstream control devices.

Step 2 – Elimination of Technically Infeasible Alternatives

All control options identified in Step 1 are technically feasible for this particular project.

With regard to CCS, it was evaluated to be a technically feasible control technology for the amine vents at the Ramsey Plant. The amine still vents produce the only high concentration CO_2

(98%) containing stream at the facility. Capturing and transporting the high purity, high concentration CO_2 streams from amine vents to a CO_2 pipeline has been reported to be technically feasible for similar facilities located in the region of the Ramsey Plant.

We also note that the plant is located within a few hundred feet of an existing 4-inch diameter CO_2 pipeline lateral that was originally installed to deliver CO_2 for an enhanced oil recovery (EOR) project. By the time Ramsey IV plant is scheduled to start operations, the CO_2 pipeline is planned to have the capacity to potentially accept 7MMSCF/D (up to 42%) of CO_2 from the Ramsey Plants' amine vents.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The control options for minimizing GHG emissions from the amine still vent are ranked below:

Control Technology	***Estimated GHG % Reduction***
Carbon Capture and Sequestration	Up to 90%
Route gas to Regenerative Thermal Oxidizer	< 1 %
Condenser	< 1 %
Flash Tank Gas Recovery	< 1 %
Flare	< 1 %

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts.

Carbon Capture and Sequestration:
Nuevo developed and submitted an evaluation of CCS cost for consideration in step 4 of the BACT analysis. As explained below, based on the specific facts of this permitting situation, Nuevo has divided its evaluation of CCS costs for two portions of the CO_2 stream from the amine vents. The specific facts of this permitting situation that impact the CCS cost evaluation are:

a) high CO_2 concentration (98% purity CO_2) in the flue gas stream from the amine still vents,
b) unique proximity of the Ramsey expansion project location to an existing 4-inch CO_2 pipeline just outside fence line,
c) capacity of the existing pipeline to take up to 7MMSCF/D of CO_2 for use in an enhanced oil recovery (EOR) projects, and
d) negotiated contract with CO_2 pipeline owner to sell up to 7 MMSCF/D of CO_2

Based on these facts, Nuevo has determined that it will be economically feasible to commit up to 7 MMSCF/D of CO_2 from the Ramsey amine still vents to CCS for EOR purposes through a contractual agreement with a CO_2 pipeline operator. Accordingly, Nuevo has proposed that CCS for EOR be considered BACT for this portion of the CO_2 stream from the amine vents (up to 42% may be eventually recovered).

EPA has evaluated the permit application and concurs with the applicant's assessment that capture and sequestration of part of the CO_2 emissions from the amine still vents is economically feasible under the particular circumstances here. Because generation of a high purity CO_2 stream is inherent to the process, there are few, if any, additional costs to the applicant of capturing and compressing the CO_2. Furthermore, the applicant has contracted with a CO_2 pipeline operator who will bear the cost of additional pretreatment of the CO_2, which would otherwise be required to place the CO_2 from this facility into EOR pipelines at other locations (see further discussion below). In addition, the pipeline costs for this facility are substantially reduced because of the close proximity of this facility to an existing CO_2 pipeline. Thus, the costs to the applicant of capturing and sequestering this part of its CO_2 emissions through an EOR process are substantially lower than the costs of CCS that have been identified as economically infeasible in prior PSD permit applications for other types of facilities (or for the remaining volume of CO_2 from this facility, as explained below).

Nuevo also evaluated the possible use of CCS for the remaining volume of CO_2 from the amine vent streams (approximately 10.83 MMSCF/D or 58%) instead of routing them to Regenerative Thermal Oxidizers (RTOs). Nuevo evaluated two CCS options for the remaining CO_2 volume:

1. Pretreatment and transferring of remaining volume of CO_2 from amine still vents via pipeline to an existing EOR CO_2 pipeline hub.
2. Pretreatment and transferring remaining volume of CO_2 via pipeline to a reservoir for storage in a geologic formation.

The main components of CCS for the remaining CO_2 volume evaluated by Nuevo included:

- *Pretreatment (i.e., capture and purification) of remaining volume of CO_2 from amine still vent vapors emission streams* - Prior to CO_2 being delivered into the pipeline, additional equipment would be needed to remove impurities (potentially sulfur and water) to meet pipeline specifications. Additional separation equipment including scrubbers and mole sieves would be needed to purify the CO_2 streams. (We note that Nuevo is not required to pretreat the approximately 42% volume of CO_2 that is being routed to the existing pipeline under its contractual agreement with a CO_2 pipeline operator).

➤ *Transferring compressed CO_2 via pipelines to an existing EOR pipeline hub or to a reservoir for storage in geological formation* - Nuevo would need to install electric or gas-fired motors for compression of the pretreated gas to pipeline pressure and temperature, as well as construct a pipeline to carry the CO_2 to an existing EOR CO_2 pipeline hub or to a reservoir for storage in a geologic formation.

Nuevo estimated the costs of these CCS components as follows:

1. <u>EOR pipeline hub</u>

The additional equipment needed to purify and compress the CO_2 stream would have an estimated capital cost of $48M, which includes the cost of a necessary booster station given the pipeline distances involved. The annual operating cost of the CO_2 capture and purification equipment is estimated to be $2,831,919. The additional natural gas-fired heating and compression equipment required to capture, purify, and compress the CO_2 stream would also increase energy consumption and heat requirements, which would result in additional emissions of GHG and criteria pollutants as well as additional operational costs. Nuevo estimated that the annual operational cost for the amine units would increase 83% by adding pretreatment and compression in order to implement CCS on the remaining volume of CO_2 to an existing EOR pipeline hub.

Nuevo determined that the best chance for selling the CO_2 would be to get it to a hub where there might be a higher demand for CO_2. The nearest hub accepting CO_2 is in Andrews County, southwest the city of Andrews, approximately 89 miles from the Ramsey expansion plants. The capital cost of pipeline construction from the Ramsey plant to the Andrew County hub was estimated using "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs"[4]. The pipeline capital cost was estimated to be approximately $66,262,177. Nuevo estimated the total annualized cost implementing CCS to be $19,860,352 and the net CCS pipeline annualized cost to be $17,828,398. The total overall annualized cost for the Ramsey expansion without CCS for the remaining CO_2 volume is $30,555,663. Nuevo estimated the potential revenue from selling the remaining volume (193,678 metric tons/215,198 short tons) of CO_2 at this hub to be $9.50/metric tons or approximately $2 million per year. Accounting for the revenue from selling CO_2, Nuevo estimated the total capital cost for implementing CCS for the remaining CO_2 from the amine vent streams to be $114,262,177 which will increase the total capital

[4] http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev3_20140514.pdf

cost for the Ramsey expansion project by 38% and increase the total annualized cost of the project by approximately 58%.[5] In addition, Nuevo has indicated the CCS equipment life is anticipated to only be 10 years based on extreme acidic conditions of the CO_2 stream which would require potential replacement of the equipment prior to the plant ceasing operations. This cost has currently not been added to the initial upfront capital costs or annualized costs.

Because Nuevo's potential revenue figures were estimates and were not based on publically available contracts or other cost information, EPA conducted further analysis of the CCS economic costs based on potential revenue estimates contained in EPA's proposed NSPS for emissions of greenhouse gases from new Electric Generating Units (EGUs) (published January 1, 2014, 79 FR 1429see 79 FR 1430 at 1475; January 8, 2014). The proposed rule utilizes a "low EOR" case assuming an EOR price of $20 per ton of CO_2, and a "high EOR" case of $40/ton of CO_2. (These EOR price estimates are the net of the costs of transportation, storage, and monitoring). Assuming an average (midrange) price of $30 per ton of CO_2, the projected sale of the remaining CO_2 at the hub would generate approximately $5.8 million in annual revenue. As noted above, Nuevo's total overall annualized cost for the Ramsey expansion without CCS for the remaining CO_2 volume is $30,555,663 and the total annualized cost implementing CCS is $19,860,352. Therefore, assuming $5.8 million in annual revenue generated, Nuevo's net CCS pipeline annualized cost would be $14,060,352, which represents an increase in the overall annual cost of the project by approximately 46%.

2. <u>Storage in Geological Formation</u>

Nuevo estimated the additional equipment needed to purify and compress the CO_2 stream would have an estimated capital cost of $32M (no booster station will be needed given the shorter pipeline distances involved). The annual operating cost of the CO_2 capture and purification equipment is estimated to be $1,208,486. The additional natural gas-fired heating and compression equipment required to capture, purify, and compress the CO_2 stream would also increase energy consumption and heat requirements, which would result in additional emissions of GHG and criteria pollutants as well as additional operational costs. Nuevo estimated the increase in annual operational cost for the amine plant to be 191% to implement CCS for the remaining CO_2 from the amine units to store in a geological formation, which includes pretreatment and compression as well as operational costs associated with the necessary injection wells (described below).

[5] This costs does not include costs for insurance or other CO_2 pipeline liability.

In Nuevo's consideration of geologic sequestration of CO_2, there were a number factors they analyzed including locating a suitable reservoir/formation for storage; acquiring the rights to store the CO_2 in the reservoir/formation; the status of pressure in the reservoir/formation; competent injection well(s) to use or to drill new wells; the presence of an existing pipeline to transport CO_2 for injection; and pretreating the amine still vent stream to remove hydrogen sulfide and other contaminants. The Ramsey plant will be located approximately 20 miles from several previously CO_2 flooded fields in the Delaware and Permian Basins. Nuevo identified the reservoirs/formations considered for geologic sequestration and the primary reason they no longer receive CO_2[6]. Given the age of the reservoirs and the age of the existing injection wells, Nuevo indicated they would need to drill new injection wells, as well as construct a pipeline to the fields. Nuevo estimated the number of injection wells needed would be 27 wells based on the volumes involved and type of reservoirs considered for geologic sequestration in the area, but clearly indicated a detailed reservoir study would need to be undertaken to determine the exact number of injections wells needed if an injection program were undertaken. The estimated pipeline capital cost is $15,426,450 and the capital cost for the injection wells is estimated to be $29,665,016 [7]. The total capital cost for implementing CCS for the remaining CO_2 from the amine vent streams to the storage in geologic formation was estimated to be approximately $77,091,467 which will increase the project capital cost by at least 26%. The total overall annualized cost for the Ramsey expansion without CCS is $30,555,663. Nuevo estimated the net annualized cost for the pipelines and geologic sequestration to be additional $18,014,305 which will increase the annual cost of the project by at least 59%.

According to the applicant, such increases in capital cost and annualized operating costs for implementing CCS for the remaining volume of CO_2 from amine still vents through use of either an EOR pipeline hub or geologic sequestration would make the project economically unviable. EPA Region 6 reviewed Nuevo's site specific CCS cost estimate and found no significant anomalies to suggest that Nuevo's analyses did not adequately approximate the cost of a CCS control for the remaining volume of CO_2 from this project. Instead Nuevo's analyses demonstrates that the capital and operational costs are excessive in relation to the costs of the proposed project without CCS for the remaining volume, especially since these costs would

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[6] Nuevo provided information on reservoirs that historically had CO_2 flood projects in the area around the Ramsey plant were looked at to come up with a preliminary estimate of the wells. See e-mail and attachment (Preliminary Estimate of Number of Wells) received on 09/26/14, and included in the records of this permitting action.

[7] Nuevo noted that these estimated costs figures did not include other costs to comply with EPA's Safe Drinking Water Act (SDWA) requirements for Federal Underground Injection Control (UIC) Class VI Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells, including; 1) rule implementation and annual administration, 2) installing monitoring wells, 3) well plugging and post injection site care (PISC), and 4) emergency and remedial response plans.

apply only to CCS for a portion (approximately 58%) of the of the CO_2 to be captured for this specific project and site location. Accordingly, CCS is eliminated as BACT for the remaining volume of CO_2 at this project.

Flare

The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Controlling the amine still vent streams with a flare would require significant supplemental fuel to maintain a pilot flame and to increase the heating value of the waste gases to the point that it can effectively combusted in a flare. Accordingly, the use of the flare would increase CO_2 and CH_4 emissions. Also flares combust at high temperature and so contribute additional N_2O emissions. The combustion of the supplemental fuel and pilot fuel result in an overall increase in the net CO_2e emission from this source. Due to the negative environmental impacts from the additional GHG and N_2O emissions generated by a flare, the use of a flare is eliminated as a control option for the amine still vents.

The remaining options for control of acid gases from the amine units are to use CCS (only for up to 42% CO_2 from amine still vents), condensers, flash tank gas recovery, and route the gas to the RTOs. Nuevo selected these remaining control options as BACT. EPA has determined that there are no negative economic, energy, or environmental impacts associated with the use of these options at this specific facility that would warrant their elimination as BACT.

Step 5 – Selection of BACT

The following BACT practices are proposed for the amine still vent stream:

- Carbon Capture and Sequestration
- Regenerative Thermal Oxidizer
- Condenser
- Flash Tank Gas Recovery

After considering the specific facts regarding CCS capture and sale at the Ramsey Plant, EPA proposes that BACT for the amine units will capture at least 35% of the CO_2 emissions on an annual basis. Nuevo proposed in its application that up to 42% of the CO_2 (up to 7 MMSCF/D) produced by the amine units at the Ramsey Plant could be transferred on any given day. This quantity may vary day-to-day based on circumstances beyond Nuevo's control. Not only will the amount of CO_2 produced in the amine still vents vary with the operation of the Ramsey Plant, but the capacity of the CO_2 pipeline system and the demand for CO_2 in the pipeline may change in ways that would reduce or increase the amount of CO_2 that can be transferred to the CO_2 pipeline system. Importantly, we note that the BACT selected in this case, partial CCS, is dependent on an offsite party contractual agreement with the CO_2 pipeline operator accepting the material for delivery for eventual sequestration (use in EOR, in this case). While it may be possible, as a purely technical matter, to capture a higher percentage of CO_2, as noted by the 90% GHG reduction figure provided in the table in Step 2 above, the sequestration component of the technology is dependent on the capacity of the CO_2 pipeline operator to accept a particular volume of CO_2. At this time, Nuevo has provided information that it can reasonably expect to sell and transfer only up to 42% of its CO_2 for EOR. Therefore, EPA has based the remaining BACT analysis for the amine still vents for this facility on the capture and sequestration of a maximum of 42% of the CO_2 produced by the amine capture units.

EPA's proposed BACT determination a minimum of 35% CO_2 capture accounts for the factors that may result in a reduction of the quantity of CO_2 captured, such a change in demand for CO_2, EOR or pipelines down periods, and operational or contractual issues. While it may be possible for Nuevo to increase the volume of CO_2 captured from the amine still vents and sent to the CO_2 pipeline, such increases are purely speculative and there is no concrete information in the current record that would allow EPA to reasonably set the BACT capture rate at a higher level. The CO_2 from the streams generated from the two amine still vents (A-4 and A-5) that are not transferred to the CCS pipeline will be recovered using condensers and flash tanks and routed to the regenerative thermal oxidizers (RTO-4 and RTO-5); a BACT limit for emissions associated with the amine unit still vents is included in the RTO BACT analysis provided below. However, regardless of the amount of stream gas recovered using condensers and flash tanks and routed to the RTOs, Nuevo must be able to demonstrate compliance with a minimum of 35% capture at the end of the calendar year. For purpose of emission estimation, Nuevo shall monitor and record the volume of gas from the amine units that is sent to the RTO and the volume that is sent to the CO_2 pipeline on a continuous basis. Records of the amount of CO_2 captured will be based on a 12-month calendar year basis by January 31 of the previous calendar year.

XII. Regenerative Thermal Oxidizers (RTO) (EPNs: RTO-4 and RTO-5)

The Ramsey Plant will use RTO (RTO-4 and RTO-5) to control the waste gas vent streams from the amine I and II plants. The acid gas stream from the amine plants, consisting primarily of CO_2 (98%) contains VOCs, H_2S, and CH_4 that must be controlled prior to venting the stream to the atmosphere. The advantages of the RTO are that it has a high destruction efficiency and it requires no supplemental natural gas to combust the waste stream. Each RTO will have hydrocarbon destruction and removal efficiency (DRE) of 99%.

Step 1 – Identification of Potential Control Technologies for GHGs

- *CCS* – Capture, compression, transport, and geological storage or use of CO_2.

- *Use of Residue Gas as Fuel* – Selection of lower carbon fuel for the pilot would result in less CO_2 formed during combustion. The residue gas has a low carbon intensity and is equivalent to pipeline quality natural gas.
- *Proper Design* – Use of well-designed RTO, instrumentation and controls to ensure efficient operation of the RTO.
- *Good Combustion, Operations, and Maintenance Practices* - Good combustions and operating practices are a potential control option by improving the fuel efficiency of the RTO.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible except for CCS. With regard to CCS, CO_2 capture technologies, including post-combustion capture, have not been demonstrated in practice on RTOs or a similar VOC control device. Moreover, while CO_2 capture technologies may be commercially available generally, we believe that there is insufficient information at this time to conclude that CO_2 capture is applicable to sources that have low volume and low concentration CO_2 streams, such as the RTOs for this project. As a result, EPA believes that CCS is technically infeasible for the RTOs and can be eliminated as BACT.

In regards to the remaining control options, EPA finds that all are technically feasible. Because the remaining technologies are already proposed for use at the project, ranking by effectiveness (Step 3) and a subsequent evaluation of each technology (Step 4) was not considered necessary for the BACT determination.

Step 5 – Selection of BACT

Nuevo proposes to utilize well designed and operated RTOs to treat the amine units' acid gas streams. Residue gas is only required for the pilot, which will produce negligible GHG emissions as CO_2e. Therefore, use of the RTO produces no significant additional GHG emissions beyond what is already present in the gas stream. The design and operation of the RTO will include the following:

- Instrumentation and Control Package including:
    - Acid gas stream flow rate monitoring
    - Fuel gas flow and usage
    - RTO temperature monitoring (perform initial performance test to establish exit temperature necessary to demonstrate 99% DRE, maintain the exit temperature to ensure 99% DRE for the VOC, continuous monitoring of exit temperature to maintain compliance with specified DRE).

- Pressure monitoring around the RTO package
- Implement vendor's recommended comprehensive inspection and maintenance program for the RTO.
- Clean and perform preventative maintenance on RTO instruments and control package once per year or according to manufacturer's specifications.

Based on the identified control technologies, proposed work practice standards, EPA is proposing an annual CO_2e emission limit of 215,192 TPY from RTO-4 and RTO-5 combined at the end of each calendar year at minimum combustion temperature of 1,550 ºF for each RTO on a 365-day rolling average.[8] Compliance shall be determined by the monthly calculations of GHG emissions using equation W-3 consistent with 40 CFR [98.233(d)(2)].

XIII. Process Fugitives (EPNs: FUG4, FUG5, and FUG6)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane and CO_2 emissions from process fugitives have been estimated at 185 TPY CO_2e per plant. Fugitive emissions of methane are negligible, and account for less than 0.01% of the projects total CO_2e.

Step 1 – Identification of Potential Control Technologies for GHGs

The following control technologies for process fugitive emissions of CO_2e are listed below:

- *Leakless Component Designs* – Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used.
- *Pneumatic Controllers (that comply with 40 CFR Part 60, Subpart OOOO)* – Use of low-bleed gas-driven pneumatic controllers emit less gas (that contains GHG) than standard gas-driven controllers, and compressed air-driven pneumatic controllers do not emit GHG.
- *Implement 40 CFR Part 60, Subpart OOOO Leak Detection and Repair (LDAR) Programs* - Method 21 monitoring is effective for identifying leaking CH_4, and although it cannot detect CO_2, it can detect mixed streams that contain CO_2 such as inlet gas or plant residual gas. Method 21 monitoring of the fuel and feed system for CH_4 is an effective method for control of GHG emissions. NSPS 40 CFR part 60 subpart OOOO requires a regular LDAR program that is believed to reduce fugitive VOC emissions by 75-93%.
- *Implement an alternate monitoring program using remote sensing* – Alternate monitoring programs, such as remote sensing technologies, have been proven effective in leak detection and repair programs under some circumstances and are also used to detect large releases of hazardous or highly flammable gases.

[8] We note that this limits represents approximately 65% of the GHGs from the amine still vents that would remain after a 35% capture rate (as proposed in BACT for the amine vents), as well as a small amount of GHGs that are produced as a result of the combustion of VOCs in the RTOs.

- *Implement an audio/visual/olfactory (AVO) monitoring program (for odorous compounds)* – Leaking fugitive's components can be identified through AVO methods. The process fluids in the piping components are expected to have discernible odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.
- *Proper facility design and construction* – A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. A second element affecting emissions is optimization of the number and type of components in the facility.
- *Replace rod packing on reciprocating compressors (as required by 40 CFR Part 60, Subpart OOOO)* – Subpart OOOO requires the replacement of rod packing on reciprocating compressors in order to reduce VOC emissions. This measure should also reduce GHG fugitive emissions from affected compressors.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The control options for minimizing GHG emissions from the process fugitives are ranked below;

Control Technology	***Estimated GHG % Reduction***
Leakless Technology	100%
Install Pneumatic controllers	97%
Alternate monitoring program using remote sensing	97%
Implement NSPS 40CFR Part 60 subpart OOOO LDAR programs	75-93%
Implement AVO monitoring program	70-90%
Replace rod packing on reciprocating compressors	80%
Proper facility design and construction	-

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Nuevo intends to implement all control technologies listed above in step 3, except for leakless technology and an alternate monitoring program using remote sensing. The total fugitive GHG annual emissions from the Ramsey (IV, V, and VI) Plants are estimated to be less than 500tons of CO_2e. The cost for using leakless technology is estimated to be three (3) to ten (10) times higher than comparable high quality valves. In addition, according to the EPA publication Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (EPA – 435/R-11-002, July 2011), control costs for alternate monitoring programs using remote sensing are expected to be $1,795 per ton for methane, the main GHG in fugitive emission. In light of these costs and the relatively small amount of GHG that could be controlled by these technologies, use of leakless technology and an alternate monitoring program using remote sensing are eliminated as not cost effective for GHG control.

Nuevo intends to implement all technologies listed above in Step 3 (except for using leakless technology and an alternative monitoring program using remote sensing), which together will reduce fugitive emissions by greater than 90%. Because an LDAR program is being implemented for VOC control purposes at Ramsey Plants, it will also result in effective control of the small amount of GHG emissions from the same piping components.

Step 5 – Selection of BACT

EPA has reviewed and concurs with Nuevo's fugitive emission sources BACT analysis. Based on Nuevo's top-down BACT analysis for fugitive emissions, Nuevo concludes that installing pneumatic controllers, implementing 40 CFR Part 60, Subpart OOOO LDAR programs, implementing AVO monitoring program, replacing rod packing on reciprocating compressors and maintaining proper facility design and construction are the appropriate BACT control technology options. A numerical limit for control of these negligible GHG emissions is not proposed.

XIV. Threatened and Endangered Species

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA), submitted March 2014, prepared by the applicant, Nuevo Midstream, LLC, and its consultant, Sound Environmental Solutions, Inc., ("SES"), and adopted by EPA.

The BA has identified twelve (12) species listed as federally endangered or threatened in Reeves County, Texas:

Federally Listed Species for Reeves County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Northern aplomado falcon	*Falco femoralis septentrionalis*
Mexican spotted owl	*Strix occidentalis lucida*
Interior Least Tern	*Sterna antillarum athalassos*
Crustaceans	
Pecos (Diminutive) amphipod	*Gammarus pecos*
Fishes	
Comanche Springs pupfish	*Cyprinodon elegans*
Pecos gambusia	*Gambusia nobilis*
Mammals	
Black-footed ferret	*Mustela nigripes*
Gray Wolf	*Canis lupus*
Mollusks	
Pecos assiminea snail	*Assiminea pecos*
Phantom springsnail	*Prygulopsis texana*
Phantom tryonia	*Tryonia cheatumi*
Plants	
Pecos/Puzzle sunflower	*Helianthus paradoxus*

EPA has determined that issuance of the proposed permit will have no effect on any of the twelve listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.
Because of EPA's "no effect" determination, no further consultation with the USFWS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XV. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties on or eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by SWCA Environmental Consultants (SWCA), on behalf of Sound Environmental Solutions, Inc. a consultant for Nuevo Midstream, submitted on May 27. 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be 39.4 acres consisting of the 30.3-acre construction footprint of the expansion project and a 100-foot (9.1-acre) buffer zone on the east, west and south sides of the site. SWCA conducted a desktop review within a 1.0-mile radius area of potential effect (APE). The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP).

Based on the results of the field survey, no archeological resources or historic structures were found within the APE. Based on the desktop review, no historic structures were identified within a one-mile radius of the APE. An Official Texas Historic Marker commemorating Pope's Crossing is located 2.6 miles northeast of the APE.
Based upon the information provided in the cultural resources report, EPA Region 6 determines that because no historic properties are located within a mile of the facility site and a potential for the location of archeological resources is low within the construction footprint itself, issuance of the permit to Nuevo Midstream LLC will not affect properties on or potentially eligible for listing on the National Register of Historic Places.

On May 19, 2014, EPA sent letters to 26 Indian tribes having historical interests in Texas to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVI. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration

(PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHG. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XVII. Conclusion and Proposed Action

Based on the information supplied by Nuevo, our review of the analyses contained in the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Nuevo a PSD permit for GHGs for the Ramsey Gas Plant, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Table 1. Facility Emission Limits[1]

EPN	Description	GHG Mass Basis		TPY CO_2e[2,5]	BACT Requirements
			TPY[2]		
COMP-15, COMP-16, COMP-17, COMP-18, and COMP-19	Ramsey IV Gas Fired Internal Combustion Compressors Engines	CO_2	75,242.5[4]	78,490[3] (15,698/engine)	412.3 lbs CO_2/MMSCF each engine See permit condition III.A.1.o
		CH_4	128.55[4]		
		N_2O	0.115[4]		
COMP-20, COMP-21, COMP-22, COMP-23, and COMP-24	Ramsey V Gas Fired Internal Combustion Compressors Engines	CO_2	75,242.5[4]	78,490[3] (15,698/engine)	412.3 lbs CO_2/MMSCF each engine. See permit condition III.A.1.p
		CH_4	128.55[4]		
		N_2O	0.115[4]		
COMP-25, COMP-26, COMP-27, COMP-28, and COMP-29	Ramsey VI Gas Fired Internal Combustion Compressors Engines	CO_2	75,242.5[4]	78,490[3] (15,698/engine)	412.3 lbs CO_2/MMSCF each engine. See permit condition III.A.1.q
		CH_4	128.55[4]		
		N_2O	0.115[4]		
H-9	Ramsey IV Hot Oil Heater	CO_2	30,718	30,750	280.5 lbs CO_2/MMSCF See permit condition III.A.2.p
		CH_4	0.58		
		N_2O	0.058		
H-11	Ramsey VI Hot Oil Heater	CO_2	30,718	30,750	280.5 lbs CO2/MMSCF See permit condition III.A.2.p
		CH_4	0.58		
		N_2O	0.058		
H-8	Ramsey IV Regeneration Heater	CO_2	18,431	18,450	168.3 lbs CO2/MMSCF See permit condition III.A.2.q
		CH_4	0.35		
		N_2O	0.035		
H-10	Ramsey V Regeneration Heater	CO_2	18,431	18,450	168.3 lbs CO2/MMSCF See permit condition III.A.2.q
		CH_4	0.35		
		N_2O	0.035		
H-12	Ramsey VI Regeneration Heater	CO_2	18,431	18,450	168.3 lbs CO2/MMSCF See permit condition III.A.2.q
		CH_4	0.35		
		N_2O	0.035		

EPN	Description	GHG Mass Basis		TPY CO_2e[2,5]	BACT Requirements
			TPY[2]		
RTO-4	Ramsey IV Regenerative Thermal Oxidizer	CO_2	107,578	215,192[9]	Minimum combustion temperature of 1,550 ˚F for each RTO on a 365-day rolling average. Good combustion practices and annual compliance testing. See permit conditions III.A.3 Assumes use of CCS to capture 35% of the CO_2 emissions from the Amine Still Vent before routing to the RTO, See Permit conditions III.A.3.c, III.A.3.d, and III.A.3.f.
		CH_4	0.73		
		N_2O	No Emission Limit Established[6]		
RTO-5	Ramsey VI Regenerative Thermal Oxidizer	CO_2	107,578		
		CH_4	0.73		
		N_2O	No Emission Limit Established[6]		
Ramsey IV-FUG4 Ramsey V – FUG5 Ramsey VI – FUG6	Process Fugitives	CO_2	1.1/plant	185 /plant[7]	Implementation of LDAR Program. See Permit conditions III.B.1
		CH_4	8.76/plant		
		N_2O	No Emission Limit Established[6]		
	Totals[8]	CO_2	557,614	568,067	
		CH_4	416		
		N_2O	1.0		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling average, except for the RTOs, emissions which will be based on a calendar year (12-consective months) basis.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Miscellaneous emissions from engines blow down per plant (for all five (5) engines in each plant) are estimated to be 0.202 TPY CO_2, 33 TPY CH_4, and 827.8 TPY CO_2e. In lieu of an emission limit, the blow down emissions will be limited by implementing a design/work practice standard as specified in the permit.
4. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the internal combustion compressor engines is for all five compressors combined for each plant. The emissions for each compressor engine shall not exceed 15,048.5 TPY CO_2, 25.6 TPY CH_4, and 0.023 TPY N_2O.
5. Global Warming Potentials (GWP): CO_2= 1, CH_4 = 25, N_2O = 298
6. These values indicated as "No Emission Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. Fugitive process emissions from EPN FUG4are estimated to be 8.76 TPY of CH_4, 1.1 TPY CO_2, and 185 TPY CO_2e. Fugitive process emissions from EPN FUG5 are estimated to be 8.76 TPY of CH_4, 1.1 TPY CO_2, and 185 TPY CO_2e. Fugitive process emissions from EPN FUG6 are estimated to be 8.76 TPY of CH_4, 1.1 TPY CO_2, and 185 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
8. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.
9. Annual CO_2e emission limit for each RTO during long term period listed in permit condition (III.A.3.g) in which all of the amine still vent emissions are routed to the RTO for control shall not exceed 165,550 TPY. The CO_2e emission from RTO-4 during the short term period listed in permit condition (III.A.3.e) shall not exceed 37,793 lbs/hr.