Statement of Basis
Greenhouse Gas Prevention of Significant Deterioration Pre-Construction Permit
for FMC Wyoming Corporation,
Granger Soda Ash Facility

Permit Number: PSD-WY-000003-2012.001

May 8, 2013

This document serves as the Statement of Basis (SOB) 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, and 40 CFR 52.37 (Federal Implementation Plan (FIP) to issue permits under the Prevention of Significant Deterioration (PSD) requirements to sources in certain states that emit greenhouse gases (GHGs)), that would apply if the permit is issued. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On May 9, 2012, FMC Corporation (FMC) submitted to the Environmental Protection Agency Region 8 (EPA) a PSD permit application for Greenhouse Gas (GHG) emissions associated with the modification of their Granger soda ash facility located near Granger, Wyoming. In connection with the same proposed project, FMC submitted a PSD permit application for non-GHG pollutants to the Wyoming Department of Environmental Quality (WDEQ) Air Quality Division (AQD) on August 31, 2012. The proposed modifications intend to optimize its operations by processing additional mine water (MW) volume from the flooded mine to fully utilize the design production capacity of the existing process equipment. This will be accomplished by providing additional MW evaporative capacity to the existing process. One new emission unit will be constructed: a Carbon Dioxide (CO_2) Stripping System will convert naturally-occurring sodium bicarbonate in the MW into sodium carbonate using steam energy. The resulting vapor stream will contain CO_2 that is liberated as a result of the conversion. A hydrogen sulfide (H_2S) absorber will capture H_2S vapors released from the process. After reviewing the application, EPA has prepared the following SOB and draft New Source Review (NSR)/PSD pre-construction air permit to authorize construction of the above described GHG air emission sources at the FMC facility.

FMC submitted additional information on July 2, 2012 to EPA. This submittal contained information to assist EPA in making determinations applicable to the Endangered Species Act (ESA) Section 7, National Historic Preservation Act (NHPA) Section 106, and issues relating to Environmental Justice (EJ).

This SOB documents the information and analysis EPA used to support decisions 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 concludes that FMC's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable PSD air permit regulations for GHGs. EPA's conclusions rely upon information provided in the permit application, supplemental information EPA

requested from and was provided by FMC, and EPA's own technical analysis. EPA is making all of this information available as part of the public record for the permit application.

II. Applicant

FMC Wyoming Corporation
P.O. Box 872
Green River, Wyoming 82935

Physical Location:
FMC Granger
Section 36, Township 20 North, Range 111 West (Seven miles north –northeast of Granger, Wyoming)
Sweetwater County, Wyoming

Operator: FMC Wyoming Corporation
Owner: FMC Wyoming Corporation
Responsible Official: Fred von Ahrens, Manufacturing Director, 307-872-2162
Alternate: Michael Wendorf, Environmental Engineering Associate, 307-872-2162
Permit Contact: Michael Wendorf, Environmental Engineering Associate, 307-872-2162

III. Permitting Authority

On December 30, 2010, EPA published a FIP making EPA the GHG PSD permitting authority for states that do not have the authority to implement GHGs PSD permitting. (75 FR 82246 (promulgating 40 CFR 52.37)) Wyoming still retains approval of its State Implementation Plan (SIP) and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD permitting authority for the state of Wyoming is:

EPA, Region 8
1595 Wynkoop St.
Denver, CO 80202

Permit Author:
Donald Law
Air Permitting Monitoring and Modeling Unit (8P-AR)
(303) 312-7015

The non-GHG PSD permitting authority for the state of Wyoming is:

Air Quality Division
Wyoming Dept. of Environmental Quality
122 West 25th Street
Cheyenne, WY 82002

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IV. Public Notice, Comment, Hearings and Appeals

Public notice for the draft PSD GHG permit will be published on May 8, 2013, in the Rock Springs Rocket. The public comment period will begin on May 8, 2013 and close on June 8, 2013 at 8:30 p.m. During the public comment period, the public will be given the opportunity to review a copy of the permit application, the draft permit prepared by EPA, the SOB, and permit-related correspondence. The draft permit, SOB, and Administrative Record for the draft permit will be available for review at EPA Region 8's office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). The permit application, draft permit and SOB will also be available for review on EPA's website at http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading. A hardcopy of these documents will also be available for review at the Sweetwater County Clerk's Office in Green River, Wyoming, Monday through Friday from 8:00 a.m. to 5:00 p.m. until the close of the public comment period.

In accordance with 40 CFR 52.21(q), *Public participation*, any interested person is afforded the opportunity to submit written comments on the draft permit during the public comment period and to request a hearing. A public hearing will be held for this action on May 21 from 7:30 PM to 9 PM at the Sweetwater County Library in Green River Wyoming. The purpose of the hearing is to gather comments concerning the issuance of the EPA GHG PSD permit. The scope of the hearing will be limited to such issues in order for the EPA to determine whether or not the applicable PSD Regulations have been appropriately applied to the construction and operation of the proposed generating station. Oral statements will be accepted at the time of the hearing, but for accuracy of the record, written statements are encouraged and will be accepted at the time of the hearing or prior thereto. Since EPA is not the permitting authority for the remainder of the NSR pollutants there will be a hearing held prior to the EPA GHG permit hearing from 6 PM to 7:30 PM on May 21 at the Sweetwater County Library in Green River, Wyoming regarding the WDEQ draft PSD permit. All comments regarding pollutants other than GHGs from the proposed facility must be submitted to the WDEQ, which is running a concurrent public comment period for this facility.

In accordance with 40 CFR 124.13, *Obligation to raise issues and provide information during the public comment period*, anyone, including the permit applicant, who believes any condition of the draft permit is inappropriate, or that EPA's tentative decision to prepare a draft permit for the project is inappropriate, must raise all reasonably ascertainable issues and submit all arguments supporting the commenter's decision, by the close of the public comment period.

Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has been already submitted as part of the administrative record in the same proceeding or consists of state or federal statutes and regulations, EPA documents of general applicability, or other generally available reference material. An extension of the 30-day public comment period may be granted if the request for an extension adequately explains why more time is needed to prepare comments.

In accordance with 40 CFR 124.15, *Issuance and Effective Date of Permit*, the permit shall become effective immediately upon issuance as a final permit, if no comments request a change in the draft permit. If changes are requested, the permit shall become effective thirty days after issuance of a final permit decision. Notice of the final permit decision shall be provided to the permit applicant and to each person who submitted written comments or requested notice of the final permit decision.

In accordance with 40 CFR 124.19, *Appeal of RCRA, UIC, and PSD Permits*, any person who filed comments on the draft permit or participated in the public hearing may petition the Environmental Appeals Board, within 30 days after the final permit decision, to review any condition of the permit decision. Any person who failed to file comments or failed to participate in the public hearing on the draft permit may petition for administrative review only on changes from the draft to the final permit decision.

V. Facility Location

The FMC facility is located in Sweetwater County, Wyoming, which is currently considered to be in attainment for all of the National Ambient Air Quality Standards (NAAQS). The nearest federal Class 1 area is Bridger Wilderness Area, approximately 80 miles away. The geographic coordinates for this facility are as follows:

Latitude: 41°40' 19.8" North
Longitude: 109° 53' 47.9" West

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

Under EPA's Clean Air Act permitting rules, the term "greenhouse gas" means an air pollutant consisting of the aggregate of six gases with atmospheric warming potential: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). GHG emissions are determined by multiplying the mass emissions of each of these gases, in tons per year (tpy) by its respective Global Warming Potential (GWP) and summing the result, which is referred to as the "CO_2-equivalent" (CO_{2e}). The GWPs (from 40 CFR 98, Table A-1 as of 10/30/2009) are 1.0 for CO_2, 21 for CH_4, and 310 for N_2O. No emissions of HFCs, SF_6 or PFCs are expected from this project.

EPA concludes that FMC's application is subject to PSD review for GHG, because the project would lead to a facility GHG emissions increase as described at 40 CFR 52.21(b)(49)(iv) and (v). The proposed project emissions would result in increased GHG emissions above both of the PSD thresholds, which are 250 tpy on a mass basis and 75,000 tpy on a CO_{2e} basis. FMC has presented CO_{2e} potential emissions of 835,972 tpy. The potential GHG emissions on a mass basis are 832,224 tpy. Of this total, approximately 147,000 tpy CO_2e are from the addition or modification of existing process equipment at the FMC facility. The remainder is from increased utilization of existing permitted equipment that will not be modified as a result of this project. EPA is the permitting authority responsible for implementing a GHG PSD FIP for Wyoming under the provisions of 40 CFR 52.21 (except paragraph (a)(1)). See 40 CFR 52.37.

As the permitting authority for regulated NSR pollutants other than GHGs, WDEQ has determined the proposed new source is subject to PSD review for non-GHG pollutants. Specifically, the PSD application submitted to WDEQ explains the proposed facility will be a major modification to an existing source. Accordingly, WDEQ is proposing to issue the non-GHG portion of the PSD permit and EPA is proposing to issue the GHG portion.[1]

EPA applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) (Guidance), available on EPA website at: www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf. Consistent with the Guidance, we have not required the applicant to model or conduct ambient monitoring for GHG, since there are no ambient air quality standards for GHGs, and we have not required any assessment of impacts of GHG in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that preparing a Best Available Control Technology (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 triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from WDEQ.

For a description of the five-step process customarily involved in making a PSD BACT determination for GHGs, please refer to the aforementioned Guidance. EPA has followed those steps in making the GHG BACT determination for this project.

VII. Project Description

The project will include the construction and operation of a new GHG emission unit, the CO_2 Stripping System, designated as UIN-50. Vapor released from the CO_2 stripping columns will be combined and vented through the H_2S absorber to the atmosphere. The absorber is a two-stage unit with a vertical counter-current spray tower that will use an alkaline liquor to capture the H_2S in the vapor stream. The absorber liquor will be a combination of purge liquor streams with the availability of untreated MW as needed in order to maintain adequate liquor volume and alkalinity. The alkaline liquor will absorb the H_2S and will be pumped to a remotely located tailings impoundment for disposal. H_2S emissions from the absorber vent exceed the PSD significance level. Therefore, FMC has applied to the WDEQ AQD for a PSD permit for emissions of non-GHG air pollutants associated with the modification.

The same vapor stream will also contain CO_2 which is formed as a result of the MW preparation process. Conversion of sodium bicarbonate (bicarb) to the desired sodium carbonate liberates CO_2 and water vapor. The conversion of the sodium bicarbonate fraction of the feedstock to sodium carbonate is a fundamental step in processing natural sodium carbonate (soda ash). The amount of CO_2 liberated per unit of feed is dependent upon the concentration of bicarb present in the feed and the efficiency of the stripping column. Historical data indicates that the concentration range of bicarb in the Granger MW is 3 - 5% by weight.

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

The facility includes a number of existing GHG emission units that will be operated in conjunction with the new modifications:

- UIN-14 No.1 Coal-Fired Boiler
- UIN-15 No. 2 Coal-Fired Boiler
- UIN-19 Emergency Diesel Fire Pump Engine
- UIN-20 Emergency Diesel Mine Generator
- UIN-21 Emergency Diesel Soda Ash Plant Generator
- UIN-45 Mine
- UIN-C01 No.3 Natural Gas-Fired Boiler
- UIN-C05 Emergency Diesel Caustic Plant Generator

Due to highly variable market conditions, the Granger facility has been operated in one of three states over the last 10 years: (a) full mothball; (b) reduced capacity; (c) ramp-up mode post mothball (i.e. less than full capacity during ramp up). As such, the boilers are expected to operate at higher steam production rates post-project compared to recent operating history, but the rates are not expected to exceed those which would have been achieved once the existing process was fully ramped-up. There is no expectation that the emergency equipment will operate more frequently; occurrences of power failures at the facility are independent of the project

The MW supply system consists of both injection and extraction wells drilled into the existing flooded mine at a depth of 1,450 ft. below ground surface level. This system has been in continuous operation since 2005 and has completely replaced the original dry ore mining and ventilation activities. Process waters are injected into the mine through injection wells that are placed in locations that promote maximum residence time for the water before it is pumped from the extraction wells. Maximum residence time enhances recovery of the trona resource left behind by dry mining. After percolating through the old mine workings, the alkali-enriched water is pumped to the plant from extraction wells.

Injection wells not actively used for injection may be placed into service as vent wells or may eventually be abandoned and decommissioned.

As the water dissolves the mine pillars, the mine roof eventually collapses into rubble, exposing a layer of oil shale that can release trapped gases. These trapped gases consist primarily of methane. The mine floor may also release trapped gases, albeit to a lesser extent. The gas migrates along the top of the mine roof until reaching a vent well, where it is released to the surface. Venting is necessary in order to allow the mine to remain open to atmospheric pressure. The water elevation in the mine is continually changing based on liquid extraction and injection rates and therefore needs to maintain a level unencumbered by pressure exerted from trapped gases. Venting is also necessary to prevent safety issues associated with sporadic liberation of mine gases that might otherwise accumulate in the MW recovery systems.

Historically, the 'Mine' emissions unit has been associated with both emission points UIN-31 and UIN-45. As part of the project, UIN-31 will be permanently decommissioned and UIN-45 will remain.

FMC conducted testing on an existing mine vent well in order to determine its methane and VOC mass emissions. Historical observations have indicated that a vent well head pressure of <0.1 PSI appears to be constant throughout the life of a vent well. Therefore, it is reasonable to assume that the volumetric flow rate of gas exiting a well is also constant. The only variation in well head pressure occurs when the well is intentionally closed in by closing its exhaust valve (increased pressure) or when it is being used for injection (no pressure). FMC has determined that a vent well must remain open at all times so as to prevent pressure from building up in the mine cavity and adversely affecting critical elevation measurements used to maintain the proper water balance.

Operational records show that as many as three injection wells have been in use simultaneously. Records for the consecutive 24-month period of CY2010 through CY2011 indicate a pattern of vent well operation that is expected to continue into the foreseeable future.

Upon completion of the project, the existing MW recovery and associated vent well operation for the Granger mine will continue to operate as it has since 2007 and would continue to operate in this mode to supply the existing Granger facility with feedstock. New injection wells that could be used as vent wells will be routinely installed in the future as the trona in the mine is dissolved and recovered.

Projected actual GHG emissions are equal to the baseline actual GHG emissions of 37,426 tons CO_2e/yr. FMC concludes that the project will not result in a net emissions increase of GHG from the mine; consequently, mine GHG emissions are not considered in this application with regard to BACT analysis.

As operation of the mine is expected to continue after the project the same as operation of the mine before the project EPA agrees that emissions from the mine are not considered to be new or modified sources and are should not be considered with regard to the BACT analysis.

Table 1 contains the overall project PTE. This includes all expected GHG emissions from existing process equipment as well as emissions associated from new process equipment. As described below in the BACT discussion, 147,000 tpy of CO_2e emissions are associated with new process equipment. The remainder of the GHG PTE emissions comes from increased utilization of existing steam generating equipment already permitted at the FMC facility. This includes the additional 61 tpy (mass) of CH_4 in the table below.

Table 1 – GHG Emissions PTE from FMC Project

GHG	Baseline Actual Emissions, tpy	Post-Project Emissions, tpy	GWP	PTE of New or Modified Equipment (as CO_2e tpy)	PTE of From Increased Utilization of Existing Equipment (as CO_2e tpy)	Total Project PTE GHG emissions (as CO_2e, tpy)	Project GHG emissions (mass, tpy)
Carbon Dioxide (CO_2)	111,131	943,286	1	147,000	685,155	832,155	832,155
Methane (CH_4)	1,792	1,853	21	0	1,284	1,284	61
Nitrous Oxide (N_2O)	2	10	310	0	2,533	2,533	8
Project Emissions, tpy						835,972	832,224

VIII. BACT Analysis

The BACT analysis provided by the applicant included the assumptions described below, which have been considered and adopted and modified by EPA in its own BACT analysis.

1. Table 1 above presents estimated FMC Granger GHG emissions in terms of CO_{2e} emissions, and only includes emissions of CO_2, CH_4, and N_2O. The project is not expected to emit HFCs or PFCs.

2. From the GHG emissions inventory presented in Table 1 above, CH_4 and N_2O total only approximately 3,817 tpy of CO_{2e} emissions, which is about 0.46% of total CO_{2e} emissions. This increase in CH4 and N2O is solely due to increased utilization of existing process equipment and is not a result of any new or modified equipment added from this project. Due to the small contribution of CH_4 and N_2O emissions to the total, the FMC Granger GHG BACT analysis includes the full five-step BACT determination process only for CO_2 emissions.

The project will include one new GHG-emitting emission unit that is subject to BACT: the CO_2 Stripping System (UIN-50). The vapor released from each of three CO_2 stripper columns is combined and vented into a H_2S absorber. The CO_2 present in the vapor will pass through the absorber and will be emitted from the absorber vent to the atmosphere.

UIN-50 CO_2 Emissions

Step 1 Identify Potential Control Technologies

A review of EPA's RACT/BACT/LEAR Clearinghouse (RBLC) and recent GHG permits issued nationwide revealed only one potential control option candidate, carbon capture and storage (CCS). FMC also considered other methods and techniques that, at least theoretically, could have the ability to capture or reduce CO_2 emissions from the process. One possible technology emerged from this review: caustic soda addition in place of CO_2 stripping columns.

Domestic natural soda ash processing is limited to six companies and is found in only three locations: four companies in Wyoming's Green River Basin, and one each in California and Colorado. Furthermore, soda ash production via MW recovery is unique to FMC; no other operation utilizes CO_2 stripping columns in this manner.

Carbon Capture and Storage (CCS)

CCS technology is composed of 3 main components: (1) CO_2 capture, including compression; (2) CO_2 transport; and (3) permanent CO_2 storage or sequestration.

CCS systems involve the use of adsorption or absorption processes to separate and capture CO_2 from the flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR) or sequestered in the ocean.

The capture of CO_2 from the gas streams can be accomplished using either physical or chemical solvents or solid sorbents. Applicability of different processes to particular applications will depend on temperature, pressure, CO_2 concentration, and contaminants in the gas or exhaust stream. Although CO_2 separation processes have been used for years in the oil and gas industries, FMC believes that characteristics of those gas streams are markedly different than exhaust generated from a soda ash plant. CO_2 separation from a soda ash plant exhaust has not been conducted on either a pilot or full scale operation anywhere in the world.

After separation, the CO_2 must be compressed to supercritical temperature and pressure for suitable pipeline transport and geologic storage properties. While compressor systems for such applications are proven, commercially available technologies, specialized equipment is required and operating energy requirements are very high.

The supercritical CO_2 would then be transported to an appropriate location for injection into a suitable storage reservoir. The transport options may include pipeline or truck transport, or in the case of ocean storage, transport by oceangoing vessels.

CO_2 storage methods include geologic sequestration, oceanic storage, and mineral carbonation. Oceanic storage has not been demonstrated in practice, as discussed below, and is not currently practical to CO_2 captured in land-locked Wyoming. Geologic sequestration is the process of injecting captured CO_2 into deep subsurface rock formations for long-term storage, which includes the use of a deep saline aquifer or depleted coal seams, as well as the use of compressed CO_2 to EOR in crude oil production operations.

Under geologic sequestration, a suitable geological formation is identified close to the project location and the captured CO_2 from the process is compressed and transported to the sequestration location. CO_2 is injected into that formation at a high pressure and to depths generally greater than 2,625 feet (800 meters).

Below this depth, the pressurized CO_2 remains "supercritical" and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock, like water in a sponge. Saline water, which already resides in the pore space, would be displaced by the denser CO_2. Over time, the CO_2 can dissolve in residual water and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2.

There are several geologic formations identified across Wyoming that might provide a suitable site for geologic sequestration. Based on the NETL 2010 Big Sky Carbon Sequestration Partnership (BSCSP) atlas, potentially suitable sequestration basins are located immediately in the vicinity of Green River and Rock Springs, Wyoming, providing potentially feasible deep saline formations (NETL, 2010). However no exploratory work or injection pilot testing into the geological formations near these areas has been conducted to date, so the actual suitability of these formations is unknown.

According to NETL/BSCSP, there are no active CCS projects operating within Wyoming, making the logistical and capital costs unclear as to the efficient use of these basins. Further, the geotechnical analyses needed to confirm their suitability have not been conducted. As such, the analysis of transport options must consider long distances potentially required to reach existing storage locations.

Ocean storage is accomplished by injecting CO_2 into the ocean water typically below 1,000 meters via pipe or ship. At these depths, CO_2 is expected to dissolve or form into a horizontal lens which would delay the dissolution of CO_2 into the surrounding environment. The depth of the overlying water and the lensing of the CO_2 will form a natural impediment to the vertical movement of the injected CO_2.
In mineral carbonation, captured CO_2 is reacted with metal-oxide bearing materials, thus forming the corresponding carbonates and a solid byproduct.

Geological sequestration of CO_2 through EOR is relatively well understood and is being implemented at full scale at many locations across the U.S. According to the CCS Interagency Task force "approximately 50 million tons of CO_2 per year are injected, produced with oil, captured, and re-injected" (ICCS, 2010). EOR consists of injecting CO_2 into an existing oil field where it can mix with crude oil, causing the conditions for additional pressure and ability to extract oil from otherwise

diminished production sites. CO_2 is then extracted from the crude oil produced and re-injected into the formation to maintain constant recovery rates. Limiting factors to EOR include transportation of captured CO_2 to available oil field operations and the availability of infrastructure to do so.

Sequestration of available CO_2 through mineral carbonation can be accomplished by combining CO_2 with available calcium or magnesium carbonates, such as serpentine or olivine to form carbonate minerals such as calcite, dolomite, and magnesite. The process is accomplished in an industrial (ex situ) setting or in situ by injecting into mineral rich deposits. Mineral carbonation has been studied for some time and the research into the practical implementation as a sequestration technology is on-going. Challenges include slow kinetic reactions, proximity of available mineral deposits to CCS operations, and the large volume of energy required to drive the carbonation process.

Caustic Soda Addition

A fundamental step in processing trona based feedstock (dry ore or aqueous brine) is the conversion of sodium bicarbonate (bicarb) to sodium carbonate (soda ash). The following equation depicts beneficiation utilizing thermal calcining:

$$2(Na_2CO_3 \cdot NaHCO_3 \cdot 2HO) \xrightarrow[\text{heat}]{} 3\,Na_2CO_3 + CO_2 + 5H_2O$$

The addition of caustic soda (NaOH) to complete the conversion or to replace thermal calcining entirely is well-known and is presently used at the FMC Granger facility in its existing configuration. The project will include caustic soda addition to complete the conversion of any residual bicarb in the stripped MW.

The following chemical equation illustrates the addition of caustic soda:

$$NaHCO_3 + NaOH \longrightarrow Na_2CO_3 + H_2O$$

Using caustic soda in place of thermal calcining would completely eliminate the release of CO_2 from the conversion process. Therefore, the potential feasibility of redefining the process by replacing the CO_2 stripping columns with total caustic soda addition was investigated.

FMC estimates that approximately 700 gpm of 10% caustic soda would be necessary in order to convert the bicarb in the MW feed and completely replace the proposed CO_2 stripping columns.

Energy Efficiency

Energy efficiency is typically examined as possible BACT for GHGs. However, for this project, the GHG emissions from new or modified units are a result of the evaporation columns. Traditional energy efficiency measures are not suitable or viable for evaporation columns because the energy source used in the evaporation columns is provided existing process steam units at the facility. These units are not being modified as a result of this project and are therefore not subject to BACT review. While there are additional increases in GHGs expected above the baseline actual emissions, these emissions are from combustion sources that are existing units and will not be modified as a part of this project. The

increased utilization of these combustion sources are already permitted under existing permits for this source.

Step 2 Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates from consideration technically infeasible options. A control technology is not considered technically feasible unless it is both available and applicable according to the New Source Review Workshop manual and sources there cited. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Carbon Capture and Storage (CCS)

Carbon capture technology has not been demonstrated in practice (or at any scale) in soda ash plant applications. Other process industries do have carbon capture systems that are demonstrated in practice, but it is unclear whether the technology used for these processes can be applied to soda ash plants due to the high concentrations of H_2S, N_2 and water vapor generated in the gas stream.

The separation of CO_2 at the FMC Granger facility as part of CCS may in theory follow a similar process as employed for combustion sources operated in the petroleum and natural gas refining processes, but full scale systems for separation of FMC's non-CO_2 flue gases (H_2O, O_2, N_2, and H_2S) have not been tested for an exhaust matrix such as that which would be generated from the FMC project's CO_2 stripping columns, The anticipated gas matrix for UIN-50 will include 200 ppm H_2S and 5% N_2. This gas matrix is based upon engineering assumptions and stack test data gathered at an FMC facility in Idaho where test results indicated about 100 ppm H_2S and about 3% N_2 from strippers operating at less than their design maximum rate and which are less efficient at sodium bicarbonate conversion than the proposed design for this project.

The applicant maintains that high concentrations of H2S and other constituents in the gas stream would make use of CCS technically infeasible for this project. The applicant notes that CO_2 is separated from petroleum refinery hydrogen plants in a number of locations, but this is typically accomplished on the product gas from a steam methane reforming process which contains primarily hydrogen (H_2), unreacted methane and CO_2. Based on the stoichiometry of the reforming process the CO_2 concentration is approximately 80 % by weight, and the gas pressure is approximately 350 pounds per square inch, gauge (psig). Because of the high concentration and high pressure, a pressure swing adsorption (PSA) process is used for the separation. In the PSA process, all non-H_2 components including CO_2 and CH_4 are adsorbed onto the solid media under high pressure. After the sorbent becomes saturated the pressure is reduced to near atmospheric conditions to desorb these components. The CO_2/CH_4 mixture in the PSA tail gas is then typically recycled to the reformer process boilers to recover the heating value.

In another example, the applicant notes that at the Dakota Gasification Company's Great Plains Synfuels Plant (GPSP) in North Dakota, CO_2 is separated from intermediate fuel streams produced from gasification of coal. The gas at GPSP from which the CO_2 is separated is a mixture of primarily H_2, CH_4, and 30 to 35 percent CO_2. A physical absorption process (Rectisol) is used at GPSP.

The applicant notes that the composition of the projected gas stream emissions from the project's UIN-50 is not a typical gas stream that is circulated through a physical or chemical absorption separation process prior to entering a pipeline for transport to a carbon storage or EOR operation. CO_2 separation at the project would theoretically follow a chemical process, but the PSA required to separate higher concentrations of conventional air pollutants has not been field tested. In a typical amine absorption process for separating out CO_2, the gas stream has a maximum concentration of 20 ppm H_2S and 0.5% N_2. In contrast, the expected gas stream from the UIN-50 of 200 ppm H_2S and 5% N_2 is ten times the amount in both instances. The applicant concludes that although CCS is recognized as being a technically viable option for various industries, the atypical nature of the gas stream of UIN-50 presents difficulties in application of existing CCS technologies to the FMC process for the reasons just stated. Thus, FMC concludes that CCS is technically infeasible for the project.

EPA disagrees with FMC's conclusion that CCS is technically infeasible for this project. Although the gas stream at the project is different in composition from those in other industries where CCS has been adopted, the applicant has not shown why this difference in composition would preclude use of CCS. In particular, higher concentrations of H_2S should not preclude use of CCS. For example, the Plains CO2 Reduction project located outside Zama City, Alberta is using production gas with H2S concentrations between 3% and 13%. (http://sequestration.mit.edu/tools/projects/zama.html) Also, the Shute Creek Treating facility outside LaBarge, Wyoming is processing gas with H2S concentrations of approximately 5%. (http://sequestration.mit.edu/tools/projects/la_barge.html). EPA thus considers CCS a technically feasible control option for the FMC project.

Caustic Soda Addition

The use of caustic soda (caustic) to convert MW bicarb is a practice that is currently employed in the existing FMC Granger operation, and therefore the technology is clearly available. However, as shown below, since the CO_2 emissions associated with the production of caustic are greater than the CO_2 emissions that could be avoided by use of caustic to neutralize bicarb, it is not technically feasible to apply this technique for CO_2 emissions control.

Caustic can be produced though the reaction of sodium carbonate with lime. Lime is formed by calcining limestone:

$CaCO_3$ + heat ---> CaO + CO_2

Stoichiometry requires that for each ton of CO_2 emissions avoided by converting bicarb using caustic, one ton of CO_2 must be emitted during lime calcination. Additionally, the energy required to remove one ton of CO_2 during the calcination of limestone is substantially higher than the energy requirement for the steam calcining method employed with this technology. Limestone is typically heated to over 2000 deg. F to liberate the CO_2. The stripping column can be operated at slightly over 200 deg. F to achieve the same result.

Consequently, the overall CO_2 emissions would be greater if lime-based caustic were used to convert bicarb, compared to the emission from the proposed project technology. Therefore, caustic addition

using lime-based caustic as a means of reducing CO_2 emissions for this project is not technically feasible.

Caustic can also be produced through the electrolysis of sodium chloride. Unlike lime based caustic production, caustic made by electrolysis of sodium chloride does not directly emit CO_2. However, caustic produced via electrolysis is highly energy intensive. One ton of electrolysis-based caustic requires about two MWH of electricity. Considerable energy is also required to concentrate caustic prior to shipment, but for simplicity the power required for electrolysis is discussed. Making a conservative assumption that the incremental electricity for caustic production could be generated from 100% combined cycled natural gas with 59% efficiency (FMC believes this to be a conservative assumption since over 45% of U.S. power is currently produced from coal and a significant portion of the natural gas based generation is from simple cycle gas turbine with much lower efficiency) the resulting CO_2 emissions for electricity production are 0.32 tons CO_2e/MWH. The production of caustic would then emit 0.64 tons of CO_2 per ton of caustic produced, just from electrical consumption. One ton of caustic used to convert bicarbonate can consume 0.55 tons of CO_2:

$$2NaOH + CO_2 \text{ ---> } Na_2CO_3 + H_2O$$

As this process would be confined to the FMC Granger facility, the CO_2 emissions from the production of a ton of electrolytic caustic (0.64 tons CO_2) are greater than the CO_2 emissions avoided from conversion of bicarb with that same ton of caustic (0.55 tons).

The use of electrolytic caustic to reduce CO_2 emissions from this project is thus also technically infeasible.

There are no add-on BACT control options which are technically feasible for UIN-50 CO_2 Stripping System.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

Based on the results of Step 2 EPA concludes that CCS is the only option remaining.

Step 4 Evaluate the Most Effective Controls and Document Results

CCS remains the only BACT option to evaluate. While CCS as a control technology for the FMC project is technically viable, further analysis indicates that this control technology is not economically viable for this project.

First, there is no currently existing infrastructure to transport CO2 from the FMC facility to a viable sequestration location. Data submitted by FMC indicates that the closest proven sequestration locations are approximately 250 miles away and located in northeastern Wyoming and southeastern Montana. The CO2 delivered there would be used in tertiary oil recovery.

Pipelines required to deliver CO2 are specialized and required to withstand pressures of approximately 2000 pounds per square inch, gauge. Estimates provided by FMC for the costs of this pipeline are estimated to be between $300,000 and $600,000 per mile, giving a total pipeline cost of $75,000,000 to

$150,000,000. This expense would be borne by this applicant, and would not be offset by any revenues derived from use of the CO2 for enhanced tertiary oil recovery.

Furthermore, the recovery and purification of CO2 from the stack gases would necessitate significant additional processing, including energy and environmental/air quality penalties, to achieve the necessary CO2 concentration for effective sequestration. The additional process equipment required to separate, cool, and compress the CO2, would result in significant adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of this system. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system, if the emissions were captured for sequestration, or reduce the net amount of GHG emissions reduction, making CCS even less cost effective than expected.

Given that FMC has provided that the entire project cost without CCS is approximately $285,000,000 and the above stated costs only includes the pipeline infrastructure and not the associated process equipment or, it is the opinion of EPA that these infrastructure costs alone demonstrate that CCS is not economically viable as a control technology for the FMC project and EPA dismisses the technology under BACT Step 4.

Step 5 Select BACT

EPA proposes incorporation of the following permit conditions for UIN-50 CO_2 Stripping System:

• Emission limits: 404 short tons per day CO_2e based on 30-day rolling average; 147,500 short tons per year CO_2e based on 365-day rolling average. The additional 500 tons above the expected 147,000 tpy CO2e PTE from UIN-50 is to allow for operational flexibility. As UIN-50 is only process unit that is new or modified as a result of this project, only the emissions from UIN-50 are subject to BACT.

• Emission monitoring: parametric monitoring using MW feed to CO_2 stripping columns in GPD, MW daily average specific gravity, percent bicarb present in MW, and application of the following equation:

CO_2 (tons/day) = [GPD] x [sp.gr.] x [% bicarb] x F

GPD = Gallons per day of MW processed. To be monitored and recorded daily.
sp.gr. = specific gravity of MW containing bicarb. To be monitored and recorded daily.
F = 8.34 lb/gal x (44 lb/mole CO_2 ÷ (2*84 lb/mole bicarb)) ÷ 2000 lb/ton

IX. Environmental Justice (EJ), Endangered Species Act (ESA), and National Historic Preservation Act (NHPA)

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

emissions of GHG, controlled by what we have determined is the BACT 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 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 EJ analysis is not necessary for the permitting record.

The EPA has reviewed the proposed action for potential impacts on historic properties in the area of potential effect (APE). Based on our review of information from the permit applicant, National Park Service National Register of Historic Places and the Wyoming State Historic Preservation Office, we have determined that the proposed action should not affect any properties listed on the National Register of Historic Places. As presently designed, the proposed project will have no effect on known cultural resources. The results of the field inspection indicated that no new or previously identified cultural resources are located within the project area. The EPA is making the finding of "*No historic properties affected*" for the APE.

The proposed modification will be constructed within the existing boundaries of the FMC Granger facility in previously disturbed areas. The EPA has concluded that the proposed GHG PSD permit action will have "*no effect*" on listed species or critical habitat. If an action agency determines that the federal action will have no effect on listed species or critical habitat, the agency will make a "*no effect*" determination. In that case, the action agency does not initiate consultation with the Fish and Wildlife Service and its obligations under Section 7 are complete.

X. Conclusion and Action

Based on the information supplied by FMC, our review of the analyses in the GHG PSD Permit Application and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed modification would employ BACT for GHG under the terms contained in the permit. Therefore, EPA is proposing to issue FMC a draft PSD permit for GHG for the described project, subject to the PSD permit conditions specified therein.