Application for PSD Greenhouse Gas Air Quality Permit to Construct for the FMC Wyoming Corporation Granger Facility

Prepared For:

U.S. Environmental Protection Agency
Region 8 Air Program
1595 Wynkoop Street
Denver, CO 80202-1129

Prepared By:

FMC Wyoming Corporation

May 9, 2012

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1.0 General Information

Date of Application:	May 9, 2012
Name of Company:	FMC Wyoming Corporation
Mailing Address:	P.O. Box 872 Green River, WY 82935
County:	Sweetwater
Telephone:	307.872.2580
Facility Location:	7 Miles NE of Granger, WY County Road 11
Responsible Official:	Fred von Ahrens Manufacturing Director
Contact for Application:	Michael Wendorf Environmental Engineering Associate, REM 307.872.2162 mike.wendorf@fmc.com
General nature of business:	Production of sodium carbonate (soda ash)
New equipment to be constructed:	Mine water evaporators Carbon dioxide stripping columns Hydrogen sulfide absorber Ancillary support equipment
Proposed date of construction:	June 2013
Proposed date of operation:	2Q 2015
Materials used in process:	Brine (mine water) containing dissolved sodium carbonate and sodium bicarbonate Coal Natural gas
Products of process:	Anhydrous sodium carbonate (soda ash)
Combustion equipment installed as part of this project:	None
Operating schedule:	8760 hr/year

"I have reviewed this application and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained herein are true, accurate, and complete."					
Signature		Typed Name	Fred von Ahrens		
Title	Manufacturing Director	Company	FMC Wyoming Corp.		
Mailing Address	P.O. Box 872		Telephone No.	307-872-2582	
City	Green River	State	Wyoming	Zip	82935
P.E. Registration (if applicable)		Not Applicable			
State where registered					

FMC

2.0 Introduction

This Greenhouse Gas (GHG) PSD air quality permit application is submitted by FMC Wyoming Corporation to obtain a permit to construct additional mine water processing equipment at the company's Granger soda ash operation located approximately 30 miles west of Green River, WY.

FMC Granger was commissioned in 1976 and was owned and operated by Tg Soda Ash until its purchase by FMC Corp in 1999. The facility has both an underground trona mine and a surface refinery which produces sodium carbonate (soda ash) for bulk sale. Primary uses for soda ash include glass manufacture, pollution control, and detergents. The facility also includes a sodium hydroxide (caustic soda) production plant; the caustic soda is used as an additive in the soda ash process.

The soda ash production facility is presently capable of processing either trona ore or mine water into refined soda ash (RSA). Its present configuration has a permitted production capacity of 650K tpy RSA using mine water as feedstock or 1.3 MM tpy RSA when using trona ore per Wyoming AQD Waiver MD-5127. In 2005, deteriorating ore quality prompted FMC to rely on the available mine water from the existing mine workings as the primary feedstock. All mining equipment was removed from underground in 2007 and the mine was subsequently flooded. With this proposed project FMC intends to optimize its operational strategy by processing additional mine water volume to fully utilize the design production capacity of the existing process equipment.

The primary goal of the FMC Granger Optimization Project is to provide additional mine water 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 mine water 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 hydrogen sulfide vapors released from the process. Details of the process are provided in Section 3 of the application.

The use of mine water as a feedstock will allow FMC to maximize utilization of the available mineral resource and while reducing emissions compared to the prior ore based operations:

- A majority of trona ore in the Green River Basin is unsuitable for economical dry mining due to depth, thickness and presence of insoluble impurities. Minewater based operations can utilize these ore sources that are unsuitable for dry mining. Furthermore, the optimized mine water process will include feedstock recovered from trona that had to be left behind during prior dry mining operations at the FMC Granger mine.

- Mine water based operations will eliminate the need for FMC Granger's trona ore stockpiling, handling, crushing, and calcining equipment, all of which produce particulate and/or gaseous emissions; the existing ore prep equipment will be permanently decommissioned as part of this project

The proposed project will create over 20 ongoing high paying manufacturing jobs in Wyoming and will increase the available U.S. natural soda ash for worldwide export. At the same time, the improvements will reduce the energy and carbon intensity of FMC soda ash operations (intensity is defined as the energy consumption or carbon dioxide emissions per unit of product). Demand for soda ash is increasing globally, thus prompting production of synthetic soda ash overseas. Natural soda ash production is considerably less energy intensive and has a lower carbon impact and production cost than its primary competition – synthetic soda ash produced in China. As a result, over 50% of U.S. natural soda ash produced in the US is presently exported, providing a significant positive trade balance for the U.S.

Natural soda ash production from the Wyoming trona basin uses 40% less energy and produces about 40% less greenhouse gas than production of the worldwide alternative, synthetic soda ash. The project proposed by FMC will increase natural soda ash production domestically, thereby reducing global energy consumption and global carbon impacts compared to synthetic soda ash manufacturing.

In fact, FMC can produce and deliver soda ash to customers around the world with fewer greenhouse gas emissions than those from synthetic soda ash production in the customers' region, or even within their home country.[1] Growing worldwide demand

[1] US average footprint for production from Industrial Minerals Association -- North America Soda Ash/Borates/Silicates Section – Green House Gas Inventory, 2010. Synthetic soda ash production from Fraunhofer Institute for Systems and Innovation Research by order of the European Commission, Methodology for the Free Allocation of Emission Allowances in the EU ETS post 2012, November 2009. European average used as a conservatively low estimate of Chinese Solvay Process synthetic soda Ash due to published energy use and greater reliance on coal. Shipping emissions and energy consumption from CO2 Emission Statistics for the World Commercial Fleet, World Maritime University Journal of Maritime Affairs, 2009. Rail emissions and energy consumption from Union Pacific Railroad http://www.uprr.com/she/emg/ graphics/fuel_efficiency.gif. Both are with CO2/Energy conversions per USDOE Instructions for Form EIA-1605, Appendix B (March 2003). Point of delivery is assumed to be a coastal port.

growth that is not supplied by U.S. natural soda ash will be supplied by the more costly and higher greenhouse gas emitting synthetic soda ash facilities. Therefore, while creating local jobs and growing our local economy, the proposed project helps minimize the global impacts of greenhouse gas emissions from synthetic soda ash production.

3.0 Project Description

Site information, plans, and the project description are provided in this section.

3.1 Site Location

The FMC Granger operation is located approximately 7 miles north-northeast of the town of Granger, in Section 36, Township 20N, Range 111W, Sweetwater County, WY. Universal Transverse Mercator (UTM) coordinates of the facility are approximately 591668 meters East, 4613893 meters North, in Zone 12. Figure 3-1 shows the regional location of the FMC Granger facility. Figure 3-2 is a facility site map which includes the proposed process building and ancillary structures within the facility.

3.2 Facility History

The FMC Granger facility originally operated an underground mine which supplied dry trona ore to the surface processing plant for the production of soda ash. Naturally-occurring mine water was also present in the mine and was pumped to the surface and used as a supplemental feedstock. As the ore quality deteriorated, mine water has become the sole feedstock to the processing plant. A combination of recycle water from the production process and fresh water is pumped into the mine via a series of injection wells, the water dissolves the soluble trona, and the resultant brine is pumped to the surface by extraction wells. Under Wyoming AQD Waiver MD-5127 granted in 2007, the facility is presently permitted to produce 650K tpy of refined soda ash (RSA) using mine water or 1.3MM tpy RSA using trona ore.

FMC Granger also operates an adjacent plant at the same facility location for the production of sodium hydroxide (caustic soda), also using mine water as feedstock. Originally intended to produce 50% caustic soda for bulk sale, it is presently only producing a 10% caustic soda solution for use in the soda ash process.

FMC Granger was operated continuously from 1976 until 2002 when market conditions forced the operation to be mothballed until 2005. It returned to operation but was again mothballed in 2009; market conditions subsequently improved and the plant resumed operation in mid- 2011.

3.3 Description of Existing Process

Figure 3-3 is a flow diagram which depicts the soda ash process in the current plant. Each process step is described in the narrative and refers to a corresponding number located on the diagram.

An alkali solution originating in the FMC Granger underground trona mine is the feedstock referred to as *mine water* (MW). This aqueous fluid contains 10% to 18% by weight of total alkalinity (dissolved sodium carbonate and sodium bicarbonate, typically referred to as TA), and is pumped to the surface and transported via pipeline from the well field to a MW clarifier *(1)* at the soda ash plant. A 10% sodium hydroxide (NaOH) solution produced at the caustic plant *(2)* is added to the MW in order to convert the sodium bicarbonate fraction to sodium carbonate. The MW passes through pressure leaf filters *(3)* to remove fine insoluble matter. The filtrate, or *crystallizer feed*, then enters evaporating/crystallizing vessels *(4)*, which concentrate the MW to produce sodium carbonate monohydrate crystals ($Na_2CO_3 \cdot H_2O$) by evaporating the excess water. The resulting *crystal slurry* passes through a centrifuge *(5)* and a steam-tube dryer *(6)* to remove the remaining moisture. The *anhydrous sodium carbonate* is sized and screened *(7)*, and is conveyed to the product storage silos *(8)* for shipment by rail car or truck. The existing trona ore preparation equipment (ore handling, crushing, calcining, and dissolving) at the front end of the plant are not included in Fig. 3-3 as they are not relevant to the process and will be physically decommissioned as part of the Project.

The existing monohydrate (mono) evaporators were designed to process feed liquor produced from dissolving trona ore in a dissolving/clarifying system. Consequently, the total alkalinity of trona ore-derived feed liquor was a function of solubility and saturation, and would result in TA concentrations of about 30% by weight. This difference in TA concentration between MW (10-18%) and ore-based feed liquor (30%) significantly reduces the processing capacity of the existing evaporators due to the additional evaporation necessary to produce crystal slurry.

Steam for the existing MW process is provided by two coal-fired boilers (UIN-14 and 15) and one existing gas boiler (UIN-C01). Each boiler produces 300 psig steam which enters a common header for distribution throughout both the soda ash and caustic plants.

3.4 Description of Granger Optimization Project

The FMC Granger Optimization Project (the 'Project') will complement the existing Granger processing equipment by adding highly efficient evaporation capacity and the ability to strip carbon dioxide (CO_2) from the MW. This will allow the existing evaporators and product dryers to operate at their original designed capacity while the processing plant uses MW as feedstock. Figure 3-4 is a rendering which shows the location of the new process building (in green) adjacent to the existing plant. Figure 3-5 is a site plan highlighting all of the new structures within the facility. Figure 3-6 is a flow diagram which depicts the Project as it would be incorporated into the current plant; the new process equipment is displayed in red. Each process step is described in the narrative and refers to a corresponding number located on the diagram.

Mine water will continue to be pumped from the mine to the existing MW clarifier *(1)*. The clarified MW then enters the new stripper/evaporator system *(2)*. MW is fed to the top of the stripping column and water vapor (steam) is fed into the bottom. The high temperature causes most of the sodium bicarbonate (bicarb) to decompose to sodium carbonate and generate CO_2, water vapor, and a small amount of hydrogen sulfide (H_2S). This vapor stream is collected from the stripping columns and sent to the H_2S absorber *(8)*. This thermal or 'steam calcining' step substitutes for calcining trona ore via a rotary kiln that is required in order to convert sodium bicarbonate in dry ore to sodium carbonate.

The stripped MW from the bottom of each column enters the new MW evaporators which evaporate some of the water and concentrate the TA in the liquid. Steam exiting the top of the stripping columns is recycled into the evaporators. Water vapor generated from the evaporation process is used in the stripping columns to decompose sodium bicarbonate and release CO_2. Mechanical compressors are used to raise the pressure and temperature of the water vapor so that it can be -used as the primary energy source for evaporation. This compression and use of steam is referred to as mechanical vapor recompression (MVR). Some makeup steam is added to this compressed stream to make up for energy that is lost in the process.

In order to further save energy, eleven (11) new heat exchangers are used in the system to preheat the MW feed by condensing hot vapor or exchanging heat with hot streams in

this part of the process. Some of the condensate is also used to heat other areas of the process and may be used as boiler feed water.

Some of the stripped MW is sent to the caustic plant *(3)* to produce a weak sodium hydroxide (caustic) additive for the soda ash process. The weak caustic is pumped back to the sodas ash plant to convert any remaining bicarb in the stripped and concentrated MW *(4)*. A clarifier and lime mud washing system *(5)* will be constructed at the caustic plant to enhance recovery of caustic soda in the process while improving caustic product quality. This new system will also reduce lime consumption which will translate into a lower volume of lime delivered to and handled at the plant.

Pressure leaf filters *(6)* are used to remove any solids remaining in the MW. The filtered material is sent to the sodium carbonate decahydrate (deca) process, which will be discussed separately.

As liquor is continually recycled in the mono crystallizers, impurities that are naturally present in the MW feed, such as chlorides, organics, and sulfates increase in concentration. In order to maximize efficiency of alkali recovery from the feedstock, deca crystallization is used to separate TA from the impurities. The purge is sent through a series of new heat exchangers and a flash tank to cool the stream before proceeding to the deca process *(7)*. This process uses evaporative or what is often called adiabatic cooling: vacuum is pulled on the new deca crystallizer causing some water to evaporate from the deca feed and the liquor to cool. As the liquor cools, sodium carbonate decahydrate ($Na_2CO_3 \cdot 10H_2O$) is formed and impurities are left in the liquor. In order to pull vacuum, cooling water is used to condense the outgoing water vapor. A new chiller and cooling tower will provide the cooling water.

The resulting deca crystals are centrifuged and sent to the deca melters *(9)* which dissolve the crystals back into solution. The high TA liquor then proceeds to the existing mono evaporators for crystallization.

Some of the mother liquor from the deca crystallizer is recycled to the deca crystallizers and a portion is purged. Despite the multi-stage processing steps the purge stream still contains some sodium carbonate, so it is used in the hydrogen sulfide (H_2S) absorber *(8)*, the details of which will be discussed in Section 3.5.

Steam requirements will be satisfied by the existing coal-fired boilers and natural gas-fired boiler. None of the three boilers will require any physical changes or changes in the method of operation as part of this Project.

3.5 GHG Emission Sources

The Project will include one new GHG-emitting emissions unit: the CO_2 stripping columns (UIN-50). As previously described, the MW is exposed to steam in the columns and the high temperature causes most of the bicarb in the MW to decompose to sodium carbonate, thus releasing CO_2 into the vapor stream, along with water vapor and a small amount of H_2S. The vapor from each of three (3) CO_2 stripping columns is combined and vented into the H_2S absorber.

The absorber is a two-stage unit with a vertical counter-current spray tower that will use alkaline scrubber liquor: a combination of deca purge liquor as previously discussed and untreated MW. The liquor will absorb the H_2S; the CO_2 in the vapor will be emitted from the absorber vent to atmosphere. A portion of the absorber liquor will be continuously purged and displaced with fresh liquor in order to maintain optimal alkalinity. The purge liquor will be pumped to a remotely located tailings impoundment for disposal.

With respect to other sources of GHG emissions, the Granger facility has the following existing emission units:

- Two (2) coal-fired stoker boilers: UIN-14, UIN-15
- One (1) natural gas-fired boiler: UIN-C01
- Three (3) emergency diesel generators: UIN-20, UIN-21, UIN-C05
- One (1) emergency diesel fire pump engine: UIN-19
- Mine: UIN-45

Potential to emit (PTE) GHG emissions from the above sources were considered in the GHG PSD permit applicability determination. Details of process GHG emissions are discussed in depth in Section 4.

3.6 Other Sources

A number of existing point sources will be decommissioned as part of the Project:

- Two trona ore handling baghouses: UIN-01, UIN-18
- One (1) trona ore crusher: UIN-03
- Two (2) trona ore gas-fired rotary calciners: UIN-04, UIN-05
- Trona ore stockpile: UIN-29

Collectively, ore calciners UIN-04 and UIN-05 have the potential to emit over 200,000 short tpy of CO_2e[1] from natural gas combustion when operated at their design production capacities. Decommissioning the units thus eliminates the potential for these GHG emissions to be generated and released into the atmosphere.

3.7 Construction and Operation Schedules

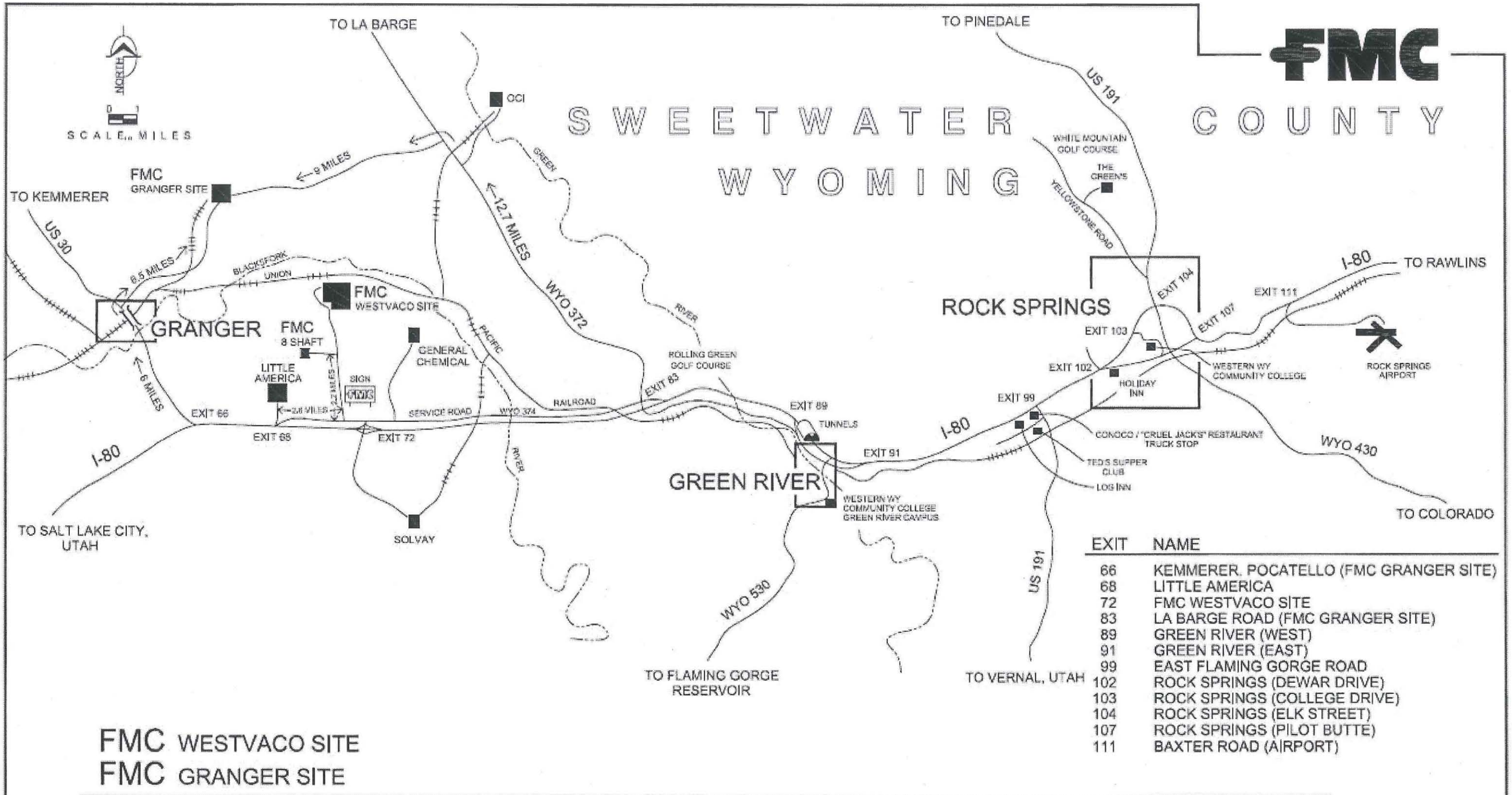
Construction of the Project will commence immediately upon receipt of all of the following permits:

- Federal EPA Greenhouse Gas PSD Permit
- WY Air Quality Division Criteria Pollutant PSD Permit
- WY Industrial Siting Division Permit

Acquisition of these permits is expected no later than June 14, 2013. Construction of the Project is expected to take twenty-six (26) months. Startup is anticipated at no more than 60 days after completion of construction activities.

[1] Based on 40 CFR 98 *EPA Mandatory Inventory Reporting Rule*, Subpart C, Tier 2, Equations C-2a, C-9a.

FIGURE 3-1



EXIT	NAME
66	KEMMERER, POCATELLO (FMC GRANGER SITE)
68	LITTLE AMERICA
72	FMC WESTVACO SITE
83	LA BARGE ROAD (FMC GRANGER SITE)
89	GREEN RIVER (WEST)
91	GREEN RIVER (EAST)
99	EAST FLAMING GORGE ROAD
102	ROCK SPRINGS (DEWAR DRIVE)
103	ROCK SPRINGS (COLLEGE DRIVE)
104	ROCK SPRINGS (ELK STREET)
107	ROCK SPRINGS (PILOT BUTTE)
111	BAXTER ROAD (AIRPORT)

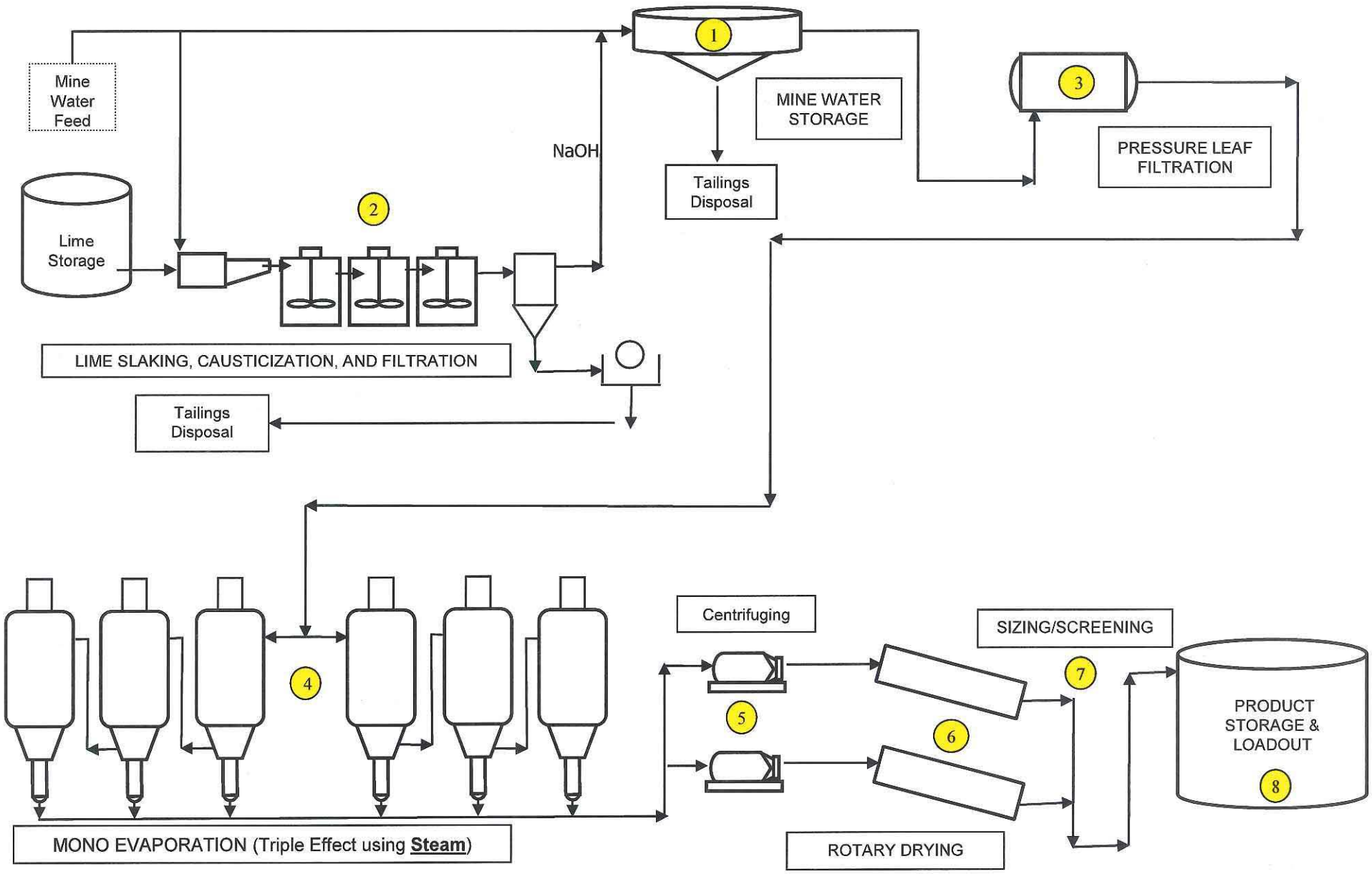
FMC WESTVACO SITE
FMC GRANGER SITE

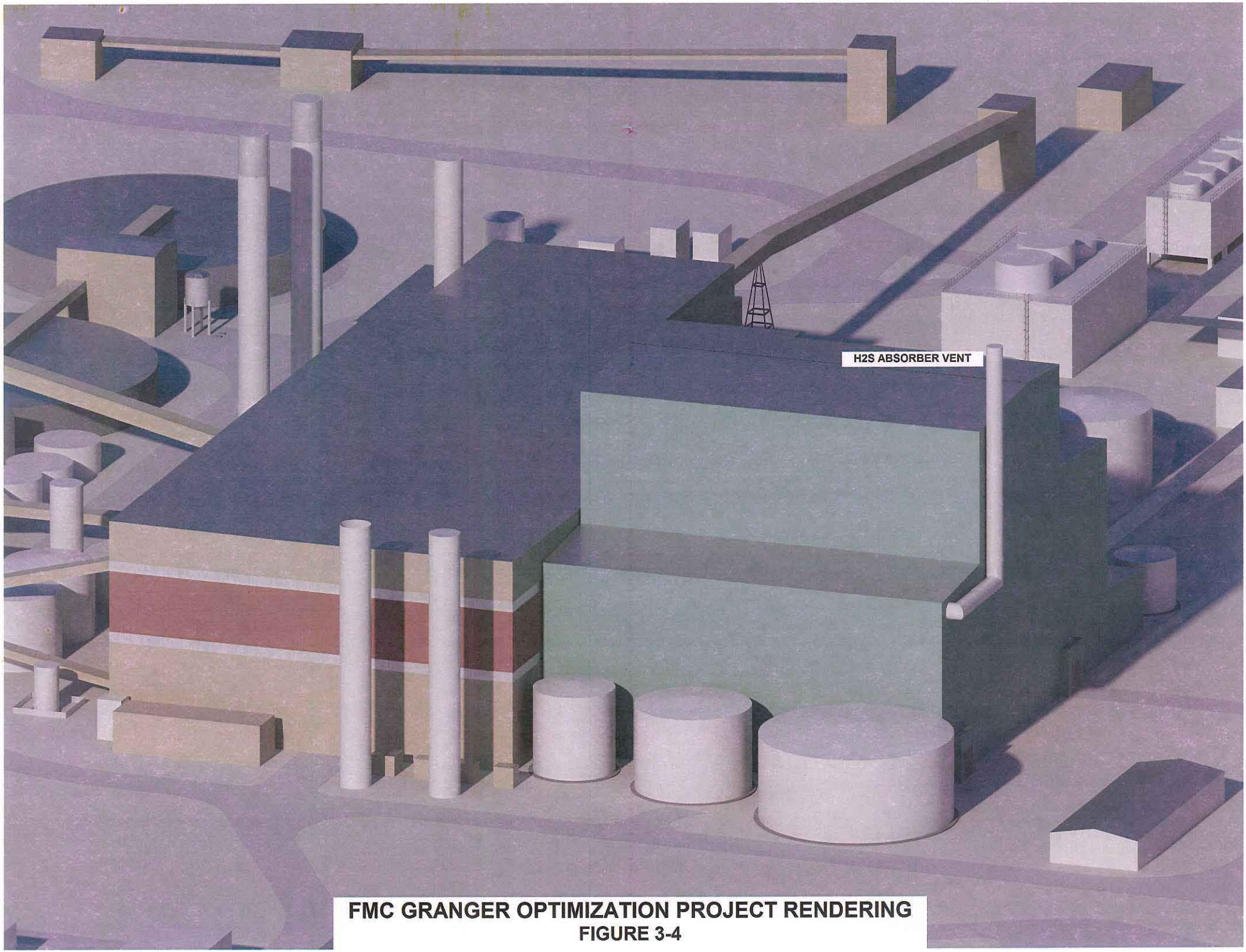
GRANGER... GREEN RIVER... ROCK SPRINGS, WY AREA MAP

AUGUST 2005

ADM01T99C01

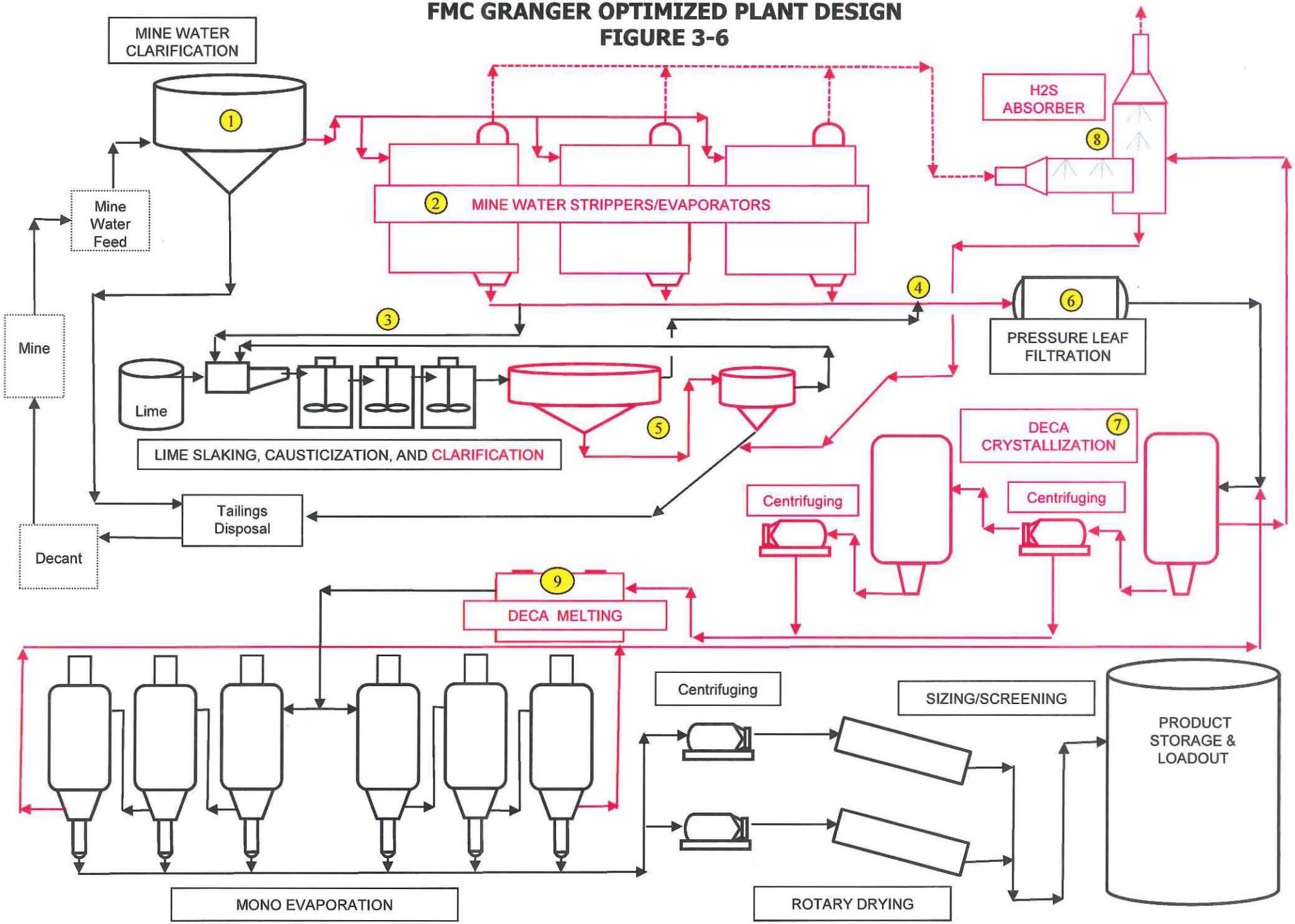
FMC GRANGER CURRENT PLANT DESIGN
FIGURE 3-3





FMC GRANGER OPTIMIZATION PROJECT RENDERING
FIGURE 3-4

FMC GRANGER OPTIMIZED PLANT DESIGN
FIGURE 3-6



4.0 GHG Emissions Summary

4.1 Carbon Dioxide (CO_2) Stripping Column System (UIN-50)

The Granger Optimization Project (the 'Project') will include the construction and operation of a new GHG emission unit, the Carbon Dioxide (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 atmosphere.

The absorber is a two-stage unit with a vertical counter-current spray tower that will use an alkaline liquor to capture the hydrogen sulfide (H_2S) in the vapor stream. The absorber liquor will be a combination of purge liquor streams with the availability of untreated mine water 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 a PSD permit application is being submitted to the WY Air Quality Division.

The same vapor stream will also contain CO_2 which is formed as a result of the mine water preparation process. Conversion of sodium bicarbonate (bicarb) to the desired sodium carbonate liberates CO_2 and water vapor. This is illustrated in the following chemical equation:

(Eq. 4-1) $$\underbrace{2(Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O)}_{\text{trona}} \xrightarrow{\text{heat}} 3Na_2CO_3 + CO_2 + 5H_2O$$

The above equation depicts *beneficiation* of trona-based feedstock (either dry ore or aqueous brine) utilizing thermal calcining. 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 mine water is 3 – 5% by weight. Therefore, based on the highest anticipated bicarb concentration of 5%, a theoretical stripping efficiency of 100%[1], and the maximum mine

[1] Stripper efficiency will be less than 100% in practical application but cannot be confirmed until actual operation.

water processing flow rate per day, an estimate of maximum CO_2 emissions from the Project can be calculated:

(Eq. 4-2) CO_2, tons = [GPD] x [sp.gr.] x [% bicarb] x *F*

= 6,517,440 x 1.1348 x 0.05 x 0.001092

= 404 short tons/day

where:

sp.gr. = 1.1348 (specific gravity of MW with 5% bicarb conc'n.)

F = 8.34 lb/gal x (44 lb/mole CO_2 ÷ (2*84 lb/mole bicarb)) ÷ 2000 lb/ton

Estimated maximum annual GHG emissions from UIN-50 are 147,500 short tons CO_2e, based on 8,760 hours/year operation.

4.2 Existing GHG Emission Units

The objective of the Project from its inception was to optimize the existing facility by restoring its production capacity without modifying the existing process equipment. The facility includes a number of existing GHG emission units that will be operated in conjunction with the new Project:

- 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-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 into the facility are independent of the Project.

Baseline actual GHG emissions and GHG potential to emit for the FMC Granger facility as a whole and for each affected emission unit can be found in Appendix A. A summary of these emissions is shown in Section 5, Table 5-1.

4.3 GHG Emissions from Mine

The mine water supply system consists of both injection and extraction wells drilled into the existing flooded mine at a depth of 1450 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. Figure 4-1 shows the mine layout and the current locations of injection wells (IW) and extraction wells (EW). Injection wells not actively used for injection may be placed into service as vent wells or may eventually be abandoned and decommissioned. A typical injection well is depicted in Figure 4-2.

As the water dissolves the mine pillars, the mine roof eventually collapses into rubble, thus exposing a layer of oil shale that can release trapped gases, primarily methane. Similarly, the mine floor may also release trapped gases but 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 a continually changing dynamic 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 mine water recovery systems.[2]

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.

Qualitative and quantitative tests were conducted 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). It has been 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.

The test results indicate a volumetric flow rate of 112 wscfm at 0.09 PSI well head pressure and an average methane emission rate of 5092.1 lb/day. Appendix B contains a summary of the test results.

Operational records show that as many as three (3) 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. Table 4-1 shows the operational record for this period:

[2] Because the FMC Granger trona mine has been flooded for secondary recovery purposes, there are no miners working underground, however, mine gases are sporadically liberated and must be vented to prevent unsafe buildup in secondary recovery systems where surface employees may be at risk. The overlying and underlying strata contain methane that is liberated as the trona is mined, either through mechanical mining or secondary recovery methods. There was an unsuccessful attempt in the early 2000s to produce methane for energy recovery from the associated strata by oil and gas operators; BLM has issued a moratorium permanently suspending oil and gas development in the known sodium lease area until underground recovery of the sodium resources is exhausted.

Table 4-1

Well No.	Venting		Vent Days	
	Start	End	2010	2011
IW-02	10/15/2011	1/1/2012	0	78
IW-05	11/15/2011	1/1/2012	0	47
IW-09	12/1/2010	1/1/2011	31	
IW-09	1/1/2011	4/16/2011		105
IW-10	3/2/2010	1/1/2011	305	
IW-10	1/1/2011	11/5/2011		308
IW-11	1/1/2010	1/1/2011	365	
IW-11	1/1/2011	6/10/2011		160
		Total Vent Days	701	698
		Vent Days, 2-Yr Average	700	

Each day in which one vent well was operational was considered a 'vent day' (*V*); the specific time of day in which a well was brought into or taken out of service was not recorded. Multiplying the daily methane emission rate test result by the annual average vent days for the consecutive 24-month period produces the baseline actual methane emission for UIN-45:

(Eq. 4-3) CH_4, tons/yr = $V \times E \div 2000$ lb/ton

= 700 x 5092.1 ÷ 2000

= 1782.2

where:

E = 5092.1 lb/day CH_4

V = 700 vent day annual average for 24-month period

Methane is the only GHG emitted from the mine, therefore baseline actual GHG emissions on a mass basis are equal to the methane emissions rate of 1,782 tons/yr. Baseline actual GHG emissions on a CO_2e basis are 37,426 tons/yr, calculated as follows:

(Eq.4-4) CO_2e, tons/yr = CH_4 tons/yr. x GWP

= 1782.2 x 21

= 37,426

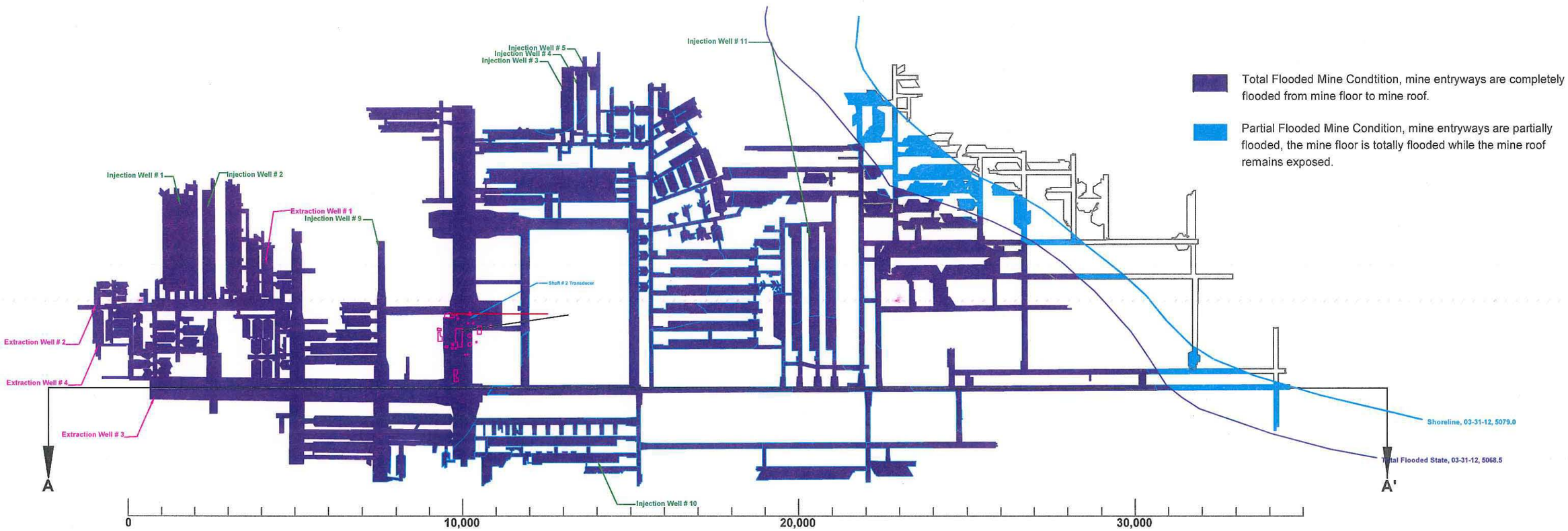
where:

GWP = Global Warming Potential of 21 for CH_4

Upon completion of the Project, the existing mine water 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, irrespective of the Project. 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/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.[3]

[3] 40 CFR 52.21(j)(3) states that BACT is applicable to an "emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit."



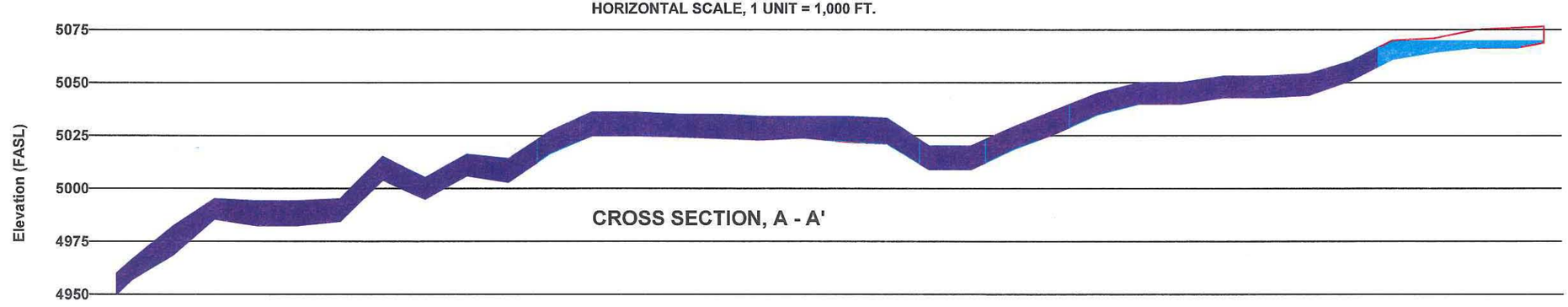


FIGURE 4-1

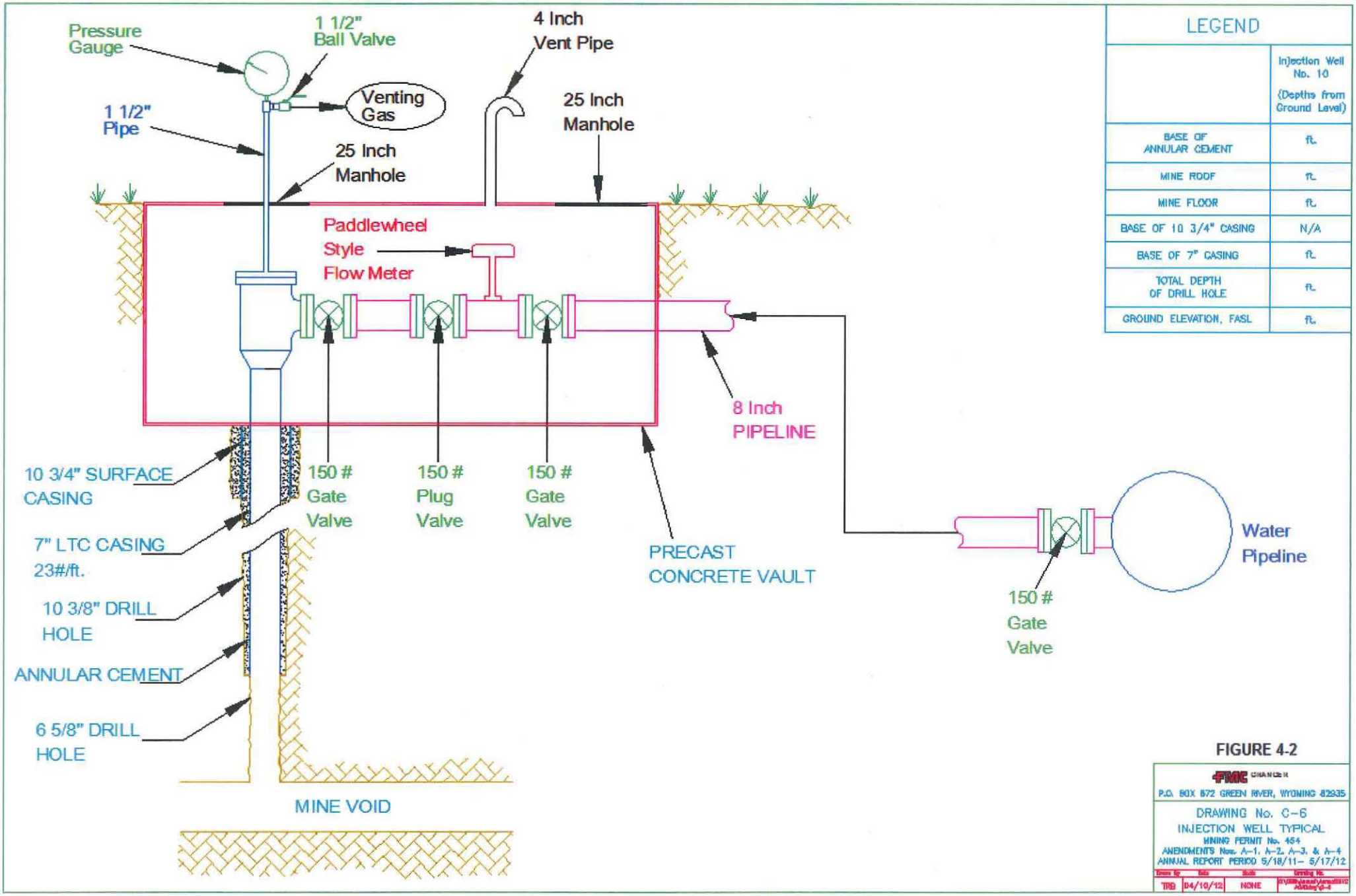
FMC GRANGER

P.O. BOX 872 GREEN RIVER, WYOMING 82935

FULLY & PARTIALLY FLOODED

MINE CONDITIONS, 03-31-12

Drawn By	Date	Scale	Drawing No.
TRB	04/11/12	H: 1 unit = 1,000 ft. V: 1 unit = 25 ft.	C:\AutoCAD\Mine FloodedMineConditions


Pressure Gauge
1 1/2" Ball Valve
4 Inch Vent Pipe
Venting Gas
1 1/2" Pipe
25 Inch Manhole
25 Inch Manhole
Paddlewheel Style Flow Meter
8 Inch PIPELINE
10 3/4" SURFACE CASING
150 # Gate Valve
150 # Plug Valve
150 # Gate Valve
7" LTC CASING 23#/ft.
PRECAST CONCRETE VAULT
Water Pipeline
150 # Gate Valve
10 3/8" DRILL HOLE
ANNULAR CEMENT
6 5/8" DRILL HOLE
MINE VOID
LEGEND
Injection Well No. 10 (Depths from Ground Level)
BASE OF ANNULAR CEMENT ft.
MINE ROOF ft.
MINE FLOOR ft.
BASE OF 10 3/4" CASING N/A
BASE OF 7" CASING ft.
TOTAL DEPTH OF DRILL HOLE ft.
GROUND ELEVATION, FASL ft.
FIGURE 4-2
FMC CHANCEY
P.O. BOX 872 GREEN RIVER, WYOMING 82935
DRAWING No. C-6
INJECTION WELL TYPICAL
MINING PERMIT No. 454
AMENDMENTS Nos. A-1, A-2, A-3, & A-4
ANNUAL REPORT PERIOD 5/18/11- 5/17/12
TRD
04/19/12
NONE

5.0 Regulatory Analysis

This section provides a regulatory analysis of federal GHG permitting requirements that are applicable to the proposed Granger Optimization Project (the 'Project'). The review is limited to federal Prevention of Significant Deterioration (PSD) requirements; as of the date of this application the Wyoming Department of Environmental Quality (WDEQ) has not adopted revisions to its PSD permitting regulations to include GHG as a pollutant subject to regulation. Consequently, EPA assumed authority for GHG PSD permitting pursuant to a Federal Implementation Plan (FIP) for the State of Wyoming, issued on December 30, 2010 (40 CFR §52.37, 75 *Fed. Reg.* 82246). A separate PSD air permit application is being submitted to WDEQ Air Quality Division for the Project's non-GHG air pollutants.

5.1 PSD Applicability and the GHG Tailoring Rule

Pursuant to 40 CFR § 52.37, the federal PSD rule at 40 CFR § 52.21 is potentially applicable with respect to emissions of GHG.

As described in the GHG Tailoring Rule (71 *Fed. Reg.* 31514, June 3, 2010), GHG's are "subject to regulation" and are therefore treated as a "regulated NSR pollutant" under the PSD program. PSD permit review is triggered if CO_2 equivalent ("CO_2e") emissions both from the existing facility and from a planned modification exceed certain thresholds.[1] These thresholds are exceeded for the Project, as discussed below.

First, the existing FMC Granger facility is an existing major stationary source due to its potential to emit pollutants other than GHG. It also has the potential to emit GHG's in excess of 100,000 tons/yr CO_2e.

Second, as discussed in Section 4 of this permit application and as summarized below, the Project will result in an emissions increase in excess of 75,000 tons/yr CO_2e. FMC Granger has not implemented changes that would generate contemporaneous and creditable decreases in actual emissions sufficient to "net out" of GHG PSD review and so, for the purposes of this permit application, has conservatively concluded that the project also will result in a net emissions increase in excess of 75,000 tons/yr CO_2e.

[1] 40 CFR § 52.21(b)(49) and (b)(50).

As discussed in Sections 4.1 through 4.3 in this permit application, the Project will involve installation of one new GHG-emitting emissions unit, relocation of certain emission points (vent wells) in the existing mine well field, and will affect the GHG emissions of several existing emissions units. Thus, as required by 40 CFR § 52.21(a)(2)(iv)(*f*) and (b)(49)(iii), the determination of the CO_2e emissions increase from the project is determined using the hybrid test. Under this test, the emissions increase is the sum of the differences between baseline actual emissions and the projected actual emissions of each affected existing emissions unit (increases only), plus the difference between the baseline actual emissions and the potential to emit of the new emissions unit (increases only). The CO_2e emissions increase, calculated in this manner, is approximately 836,000 tons/yr. Results of the applicability test are shown in Table 5-1 (emissions are in short tons):

Table 5-1

GHG	Baseline Actual Emissions, tpy	Post-Project Emissions, tpy	GWP Factor	GHG Emissions	
				as CO_2e, tpy	mass, tpy
Carbon Dioxide (CO_2)	111131	943286	1	832155	832155
Methane (CH_4)	1792	1853	21	1284	61
Nitrous Oxide (N_2O)	2	10	310	2533	8
		Project Emissions, tpy		835972	832224

Calculations for BAE and Post-Project emissions are found in Appendix A.

Because GHG's are a "regulated NSR pollutant," applicability of the preconstruction PSD permitting program is triggered for the Project if it would result in both a significant GHG emissions increase and a significant net GHG emissions increase. Pursuant to 40 CFR § 52.21(b)(23)(ii), the significant level for GHG's is "any emissions rate." As shown in Table 5-1, the increase in mass-based GHG emissions is approximately 832,000 tons/yr, which is significant. FMC Granger has not implemented changes that would generate contemporaneous and creditable decreases in actual GHG emissions sufficient to "net out" of PSD review and, for the purposes of this permit application, has conservatively assumed that the project also will result in a significant net increase in GHG emissions.

5.2 Best Available Control Technology (BACT) Applicability

In accordance with 40 CFR 52.21(j)(3), BACT is applicable to *"each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit."* The CO_2 Stripping System (UIN-50) will be the single new emission unit and will have a net emission increase of GHG; therefore, UIN-50 is subject to BACT applicability. The BACT analysis can be found in Section 6.

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

- 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-C01 No.3 Natural Gas-Fired Boiler
- UIN-C05 Emergency Diesel Caustic Plant Generator

The boilers are expected to operate at higher utilization rates post-project; however, those rates will be within the existing rates for which the equipment is permitted. There is no expectation that the emergency equipment will operate more frequently; occurrences of power failures into the facility are independent of the Project.

Because these existing emission units will not undergo a physical change or a change in method of operation, they are not subject to BACT analysis.

Emissions of GHG (methane) from mine water recovery activities (UIN-45) were included for purposes of PSD applicability. Details of the mine configuration, the recovery operation, and the release of methane from the associated vent wells are described in Section 4.

The mine water recovery process at FMC Granger has been operated in its present configuration since 2007. It is a methodical progression of well installation that allows injection and extraction in various locations as the underground mine water reservoir develops. The future mine water recovery operation will continue to follow this

progression, and would do so irrespective of the Project in order to supply feedstock for the existing soda ash facility. FMC considers the mine to be an affected emission unit and has determined that there will be a zero net emission increase of GHG (methane) from the mine as a result of the Project.

Based on the assertion of no net emission increase and on the definition of BACT applicability from 40 CFR 52.21(j)(3), Mine (UIN-45) is not subject to BACT analysis.

5.3 Impacts Analysis

In addition to BACT, the preconstruction PSD permitting program includes several other requirements applicable to the owner or operator of a stationary source undergoing a major modification. These requirements are as follows:

- Pursuant to 40 CFR § 52.21(k) and (l), the owner or operator must demonstrate that the allowable emissions from the major modification will not cause or contribute to a national ambient air quality standard (NAAQS) or a PSD increment.
- Pursuant to 40 CFR § 52.21(m), to the extent determined necessary by EPA, the owner or operator must include in the permit application an analysis of ambient air quality in the area surrounding the major modification and must conduct post-construction ambient monitoring.
- Pursuant to 40 CFR § 52.21(o), the owner or operator must provide both an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the major modification and general commercial, residential, industrial and other growth associated with the major modification, and an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the major modification. These are known as the "additional impacts" analyses.

In its interpretive guidance, EPA has established its policy that these demonstrations and analyses are not applicable with respect to GHG emissions:

> In addition to performing BACT, the source must analyze impacts on ambient air quality to assure that no violation of any NAAQS or PSD increments will result, and must analyze impacts on soil, vegetation, and visibility. In addition, sources or

modifications that would impact Class I areas (e.g., national parks) may be subject to additional requirements to protect air quality related values (AQRVs) that have been identified for such areas. Under PSD, if a source's proposed project may impact a Class I area, the Federal Land Manager is notified and is responsible for evaluating a source's projected impact on the AQRVs and recommending either approval or disapproval of the source's permit application based on anticipated impacts. There are currently no NAAQS or PSD increments established for GHGs, and therefore these PSD requirements would not apply for GHGs, even when PSD is triggered for GHGs. However, if PSD is triggered for a GHG emissions source, all regulated NSR pollutants which the new source emits in significant amounts would be subject to PSD requirements. Therefore, if a facility triggers review for regulated NSR pollutants that are non-GHG pollutants for which there are established NAAQS or increments, the air quality, additional impacts, and Class I requirements would apply to those pollutants.[2] (Emphasis added.)

Since there are no NAAQS or PSD increments for GHGs, the requirements to demonstrate that a source does not cause or contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs. EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs. Furthermore, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations.[3] (Internal citation omitted.)

Consistent with these policy statements, EPA has not required these demonstrations and analyses with respect to GHG emissions in the three PSD permits for which EPA is acting as the GHG permitting authority and has taken final action.[4] For example, in describing the required analysis for a power plant in Texas, EPA Region 6 stated as follows:

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[2] See, GHG Tailoring Rule, 71 *Fed. Reg.* 31514 at p. 31520.
[3] See, "PSD and Title V Permitting Guidance for Greenhouse Gases," EPA-457/B-11-001, March 2011, at pp. 47-48.
[4] These are Permit Number OCS-EPA-R4007, issued by EPA Region 4 on 10/27/2011 to Eni US Operating Company Inc.;Permit Number PSD-TX-1244-GHG, issued by EPA Region 6 on 11/10/2011 to the Lower Colorado River Authority; Permit Number DPA-EPA-R4001, issued by EPA Region 4 on 12/1/2011 to Port Dolphin Energy LLC.

> [W]e have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of GHGs in the context of the additional impacts analysis or Class I area provisions.[5]

5.4 Proposed Permit Conditions

FMC 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 of daily averages; 147,500 short tons per year CO_2e based on cumulative 30-day rolling averages for calendar year
- Emission monitoring: parametric monitoring using mine water (MW) feed to CO_2 stripping columns in GPD, MW daily average specific gravity, and application of Equation 4-2

FMC proposes to perform the following activities in order to confirm annual methane emissions from the UIN-45 Mine:

- Determine and record the *daily* operational status of each vent well – open or closed
- Measure and record the wellhead pressure *monthly* of each open vent well
- Conduct *annual* EPA Method 18 and 25 emission tests on an open vent well to assess any change in methane emission concentration
- Calculate emissions using Equation 4-3 to determine *annual* methane emissions

[5] See, "Statement of Basis: Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Lower Colorado River Authority, Thomas C. Ferguson Plant, Permit Number PSD-TX-1244-GHG," September 2011, EPA Region 6.

6.0 Best Available Control Technology (BACT) Analysis

As described in Section 5.2, a Best Available Control Technology (BACT) analysis is required for GHG emissions from the new CO_2 Stripping System (UIN-50). This section of the permit application presents FMC Granger's proposed BACT determination.

6.1 BACT Methodology

The PSD regulations at 40 CFR § 52.21(j)(3) establish the trigger for BACT applicability. The scope of review by EPA Region 8 is limited to GHG emissions increases and BACT applicability for appropriate emissions units of GHGs. A separate PSD application is being submitted to the Wyoming Air Quality Division to address BACT requirements for increased emissions of non-GHG pollutants resulting from the Project.

Under the Federal Clean Air Act, BACT is "an emission limitation based on the maximum degree of reduction of [a pollutant], which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant."[1]

The BACT analysis performed by FMC for the GHG emissions from UIN-50 was conducted using the "top-down" methodology, which is a process described by EPA in its draft *New Source Review Workshop Manual (October 1990)* and in its *PSD and Title V Permitting Guidance for Greenhouse Gases.*[2] The five steps in this methodology are as follows:

- Step 1: Identify all potentially applicable control technologies;
- Step 2: Eliminate technically infeasible options;
- Step 3: Rank remaining technologies by control effectiveness;
- Step 4: Evaluate most effective controls and document results; and,
- Step 5: Select BACT.

[1] 42 U.S.C. § 7479(3). See, also, 40 CFR § 52.21(b)(12).
[2] EPA-457/B-11-001, March 2011.

6.2 Source Description

The existing FMC Granger facility is dedicated to the production of refined soda ash from the proximate trona ore resource owned by FMC Wyoming Corporation in Sweetwater County, Wyoming, in a manner that is economically viable. As discussed in this application, based upon the growing demand for product, the natural conditions of the local mine resource, and the undesired impacts of synthetic soda ash production, FMC has determined that the only economically viable production process at the Granger facility is through the processing of mine water (MW) as described in Section 3.3, including thermal conversion of the sodium bicarbonate fraction of the feedstock to sodium carbonate through stripping. The fundamental business and basic design objectives of the existing stationary source are economic production from the local natural resource utilizing existing equipment to the greatest extent possible. The BACT analysis presented in Sections 6.3 through 6.7, below, is evaluated in this context. Alternative raw materials, production processes, or products that would be inconsistent with these fundamental objectives or basic design would impermissibly redefine the source and are not a part of the BACT analysis.

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 (3) CO_2 stripper columns is combined and vented into a hydrogen sulfide absorber. The vapor stream will be composed of nitrogen, oxygen, water vapor, approximately 240 lb/hr hydrogen sulfide (H_2S), and 33654 lb/hr carbon dioxide (CO_2) at maximum design capacity of the stripping columns. The CO_2 present in the vapor will pass through the absorber and will be emitted from the absorber vent to atmosphere.

6.3 Step 1: Identification of 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)

The lack of additional suitable control technologies from the public domain is not surprising; 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. Consequently, the emission matrix is unique among soda ash-related emissions units.

Technical engineering resources within FMC 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:

- Caustic soda addition in place of the CO_2 stripping columns

Each of the above identified technologies will be described in the following sections.

6.3.1 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 through ocean sequestration.

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, the 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, a unique gas stream, 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 ocean-going 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 obviously inapplicable to CO_2 captured in the center of the continent. 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 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 CO2 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, silica for example.

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 rates. 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 existing infrastructure and an uncertain regulatory framework in addressing increased pressure rates and public health concerns.

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.

6.3.2 Caustic Soda Addition

As previously described in Section 3.0, 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:

(Eq. 6-1) $$\underset{\text{trona}}{2(Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O)} \xrightarrow[\text{heat}]{} 3Na_2CO_3 + CO_2 + 5H_2O$$

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:

(Eq. 6-2) $$NaHCO_3 + NaOH \rightarrow Na_2CO_3 + H_2O$$

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.

It is estimated that approximately 700 gpm of 10% caustic soda would be necessary in order to convert the bicarb in the mine water feed and completely replace the proposed CO_2 stripping columns.

6.4 Step 2: Eliminate Technically Infeasible Options

The second step in the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1. For each option that was identified, a technology evaluation was conducted to determine the technical feasibility. The technology is feasible only when the technology is available and applicable. A technology that is not commercially available for the scale of the project is also considered infeasible. An available technology is applicable only if it can be reasonably installed and operated on the proposed project. As suggested in the *1990 Draft EPA New Source Review Workshop Manual*, control technologies should be demonstrated in practice on full scale operations in order to be considered available within a BACT analysis. "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

6.4.1 Carbon Capture and Storage (CCS)

Carbon capture technology has not been demonstrated in practice in soda ash plant applications. Other process industries do have carbon capture systems that are demonstrated in practice, but the technology used for these processes cannot be applied to soda ash plants due to the high concentrations of H_2S, N_2 and water vapor generated in the gas stream.

While many believe that CCS will allow the future use of fossil fuels while minimizing GHG emissions, there are a number of technical barriers concerning the use of this technology for emissions generated by UIN-50:

- The separation of CO2 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 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 Project's CO_2 stripping columns,

- Use of captured CO_2 for EOR is widely believed to represent the practical first opportunity for CCS deployment; however, identification of depleted oil reservoirs

with owners and operators considering tertiary oil recovery is beyond the normal expertise for FMC. Furthermore, the volume of CO2 available from the proposed project is magnitudes lower than the scale of CO2 capture and pipeline projects being utilized for EOR, eliminating the possibility of financial feasibility even if technical feasibility were achieved.

- Little experience exists with other types of storage systems such as deep saline aquifers and mineral carbonation and unmineable coal formations (geological sequestration), and ocean systems (ocean sequestration) are not practicably available on a regional basis,

- FMC Granger has extensive experience injecting fluids into its existing mine workings; however, injection of CO_2 into the mine would concentrate sodium bicarbonate (bicarb) in the mine water (MW). The source of the CO_2 emissions from UIN-50 is the result of converting bicarb in the MW into sodium carbonate, thus liberating CO_2 (see Eq. 4-1). Any CO_2 that is injected into the mine will result in a one-to-one ratio of *additional* CO_2 that must be stripped from the mine water in order to produce soda ash product. Consequently, CO_2 injection into the existing mine would generate a product (bicarb) in the mine water that is inconsistent with the fundamental objective of the Project.

- Because of the developmental nature of CCS technology, vendors and contractors do not offer turn-key offerings; separate contracting would be required for capture system design and construction; compression and pipeline system routing, siting and licensing, engineering and construction; and geologic storage system design, deployment, operations, and monitoring,

- Significant legal uncertainties still exist regarding relationships between land surface ownership rights and subsurface (pore space) ownership, potential conflicts with other uses of land such as exploitation of mineral rights, management of risks and liabilities, etc,

Therefore, the CCS alternative is not considered technically feasible for the Project, and is eliminated from further consideration.

6.4.2 Caustic Soda Addition

The use of caustic soda (caustic) to convert mine water sodium bicarbonate (bicarb) is a practice that is currently employed in the existing FMC Granger operation, and therefore the technology is clearly available. However, 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 sodium bicarbonate, 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:

$$CaCO_3 + \text{heat} \rightarrow CaO + CO_2.$$

Stoichiometry requires that for each ton of CO_2 emissions avoided by converting sodium bicarbonate 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 sodium bicarbonate, compared to the emission from the proposed project technology. Therefore, caustic addition using lime-based caustic is technically infeasible.

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 (2) 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 (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:

$$2NaOH + CO_2 \rightarrow Na_2CO_3 + H_2O$$

Therefore, 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). Thus, the use of electrolytic caustic to reduce CO_2 emissions from this project is also technically infeasible.

FMC concludes from this analysis that there are no BACT control options which are technically feasible for UIN-50 CO_2 Stripping System.

6.5 Step 3: Rank Remaining Technologies by Control Effectiveness

Based on the results of Step 2 FMC concludes that there are no remaining technologies to evaluate for control effectiveness.

6.6 Step 4: Evaluate Most Effective Controls and Document Results

Based on the results of this analysis there are no control options to evaluate in Step 4.

6.7 Step 5: Select BACT

FMC 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 of daily averages; 147,500 short tons per year CO_2e based on cumulative 30-day rolling averages for calendar year
- Emission monitoring: parametric monitoring using mine water (MW) feed to CO_2 stripping columns in GPD, MW daily average specific gravity, and application of Equation 4-2

Appendix A

GHG Emission Calculations

FMC

FMC GRANGER OPTIMIZATION PROJECT - GHG PTE EMISSION TABLE

Source ID	Source	Hours	Fuel	Units	GHG						CO_2e
					CO_2	Ref	CH_4	Ref	N_2O	Ref	short tons
UIN-14	No. 1 Coal-Fired Boiler	8760	167500	tons coal	346330	*2*	34.9	*3*	5.1	*3*	348639
UIN-15	No. 2 Coal-Fired Boiler	8760	167500	tons coal	346330	*2*	34.9	*3*	5.1	*3*	348639
UIN-19	Emergency Fire Pump Engine	500	6596	gal. fuel oil	77	*5*	0.0	*5*	0.0		78
UIN-20	Emergency Mine Generator	500	45177	gal. fuel oil	526	*5*	0.3	*5*	0.0		532
UIN-21	Emergency Plant Generator	500	24326	gal. fuel oil	283	*5*	0.1	*5*	0.0		287
UIN-45	Mine	700	NA	NA	0	*1*	1782.5	*1*	0.0		37432
UIN-50	CO_2 Stripping System	8760	NA	NA	147414	*6*	0.0		0.0		147414
UIN-C01	No. 3 Gas-Fired Boiler	8760	1668571	kscf	102078	*4*	0.0	*3*	0.0	*3*	102078
UIN-C05	Emergency Caustic Generator	500	21348	gal. fuel oil	248	*5*	0.1	*5*	0.0		251
		Potential to Emit, tons			943286		1853		10		**985349**

FMC Granger Optimization Project- GHG PTE Emission Table

References

1. Emissions based on 03/2012 test results from IW10:

CO_2e = 212.2 lb/hr CH_4 x 24 hr/day x vent days ÷ 2000 lb/ton x 21 GWP

2. Coal boiler CO_2 emissions estimated using GHG Mandatory Inventory Rule (MIR) equations:

Eq. C-3 for solid fuel: CO_2, tpy = 44/12 x tons coal x %C/100

%C estimated via regression of BTU/lb vs. %C from 2010 analytical data; assumed to be represenatative of coal from the same mine in baseline period:

%C = -4.8607 + 0.00613*x*, where *x* = BTU/lb

3. CH_4 and N_2O emissions estimated using MIR equation:

Eq. C-8: CH_4 or N_2O, tpy = 0.001 x Fuel x HHV x *EF*/0.91

where: HHV = 17.25 (coal)
0.001028 (nat gas)

CH_4 *EF* = 0.011 (coal)
0.001 (nat gas)

N_2O *EF* = 0.0016 (coal)
0.0001 (nat gas)

4. Gas boiler CO_2 emissions estimated using MIR equation:

Eq. C-2a for gaseous fuel: CO_2, tpy = 0.001 x scf gas x HHV x EF/0.91

where: HHV = 0.001050 MMBTU/scf
EF = 53.02

5. Diesel engine CO_2 emissions estimated using AP42 Ch.3, Sec. 4, Table 3.4-1:

CO_2, tpy = 165 lb/MMBtu x 0.141 MMBtu/gal x gal. fuel ÷ 2000 lb/ton

CH_4, tpy = (0.09 x .09) x 0.141 MMBtu/gal x gal. fuel ÷ 2000 lb/ton

Gal. fuel estimated for 500 hr/yr operation based on the following heat inputs:

UIN-19 = 1.86 MMBtu/hr
UIN-20 = 12.74 MMBtu/hr
UIN-21 = 6.86 MMBtu/hr
UIN-C05 = 6.02 MMBtu/hr

6. CO_2, tons = [GPD] x [sp.gr.] x [% bicarb] x F x CY

where: GPD = 6,517,440 gal/day mine water
sp. gr. = 1.1348 (specific gravity of MW with 5% bicarb conc'n.)
% bicarb = 0.05 (5%)
F = 0.001092, based on: (8.34 lb/gal x (44 lb/mole CO_2 ÷ (2*84 lb/mole $NaHCO_3$)) ÷ 2000 lb/ton)
CY = 365 days/yr

FMC GRANGER OPTIMIZATION PROJECT - GHG BASELINE ACTUAL EMISSION TABLE

2010 ACTUAL EMISSIONS

Source ID	Source	Hours	Fuel	Units	GHG						CO_2e
					CO_2	Ref	CH_4	Ref	N_2O	Ref	short tons
UIN-14	No. 1 Coal-Fired Boiler	0	0	tons coal	0		0		0		0
			0	gal. fuel oil	0		0		0		0
UIN-15	No. 2 Coal-Fired Boiler	0	0	tons coal	0		0		0		0
			0	gal. fuel oil	0		0		0		0
UIN-19	Emergency Fire Pump Engine	0	0	gal. fuel oil	0		0		0		0
UIN-20	Emergency Mine Generator	0	0	gal. fuel oil	0		0		0		0
UIN-21	Emergency Plant Generator	0	0	gal. fuel oil	0		0		0		0
UIN-45	Mine	701		vent days	0		1785.0	*1*	0		37486
UIN-C01	No. 3 Gas-Fired Boiler	0	0	kscf	0		0		0		0
UIN-C05	Emergency Caustic Generator	0	0	gal. fuel oil	0		0		0		0
									2010 Emissions		37486

2011 ACTUAL EMISSIONS

Source ID	Source	Hours	Fuel	Units	GHG						CO_2e
					CO_2	Ref	CH_4	Ref	N_2O	Ref	short tons
UIN-14	No. 1 Coal-Fired Boiler	4436	60272	tons coal	123090	*2*	12.6	*3*	1.8	*3*	123921
			21650	gal. fuel oil	75	*2*	0.0	*3*	0.0	*3*	76
UIN-15	No. 2 Coal-Fired Boiler	3479	42913	tons coal	87639	*2*	8.9	*3*	1.3	*3*	88230
			16979	gal. fuel oil	59	*2*	0.0	*3*	0.0	*3*	60
UIN-19	Emergency Fire Pump Engine	14	185	gal. fuel oil	2	*5*	0.0	*5*	0		2
UIN-20	Emergency Mine Generator	0	0	gal. fuel oil	0	*5*	0.0	*5*	0		0
UIN-21	Emergency Plant Generator	28	2204	gal. fuel oil	26	*5*	0.0	*5*	0		26
UIN-45	Mine	698		vent days	0		1777.4	*1*	0		37325
UIN-C01	No. 3 Gas-Fired Boiler	2229	185869	kscf	11371	*4*	0.0	*3*	0.0	*3*	11371
UIN-C05	Emergency Caustic Generator	0	0	gal. fuel oil	0	*5*	0.0	*5*	0		0
									2011 Emissions		261011
	Average Baseline Actual Emissions, tons				111131		1792		2		**149248**

GHG Baseline Actual Emission Table

References

1. Emissions based on 03/2012 test results from IW10:

CO_2e = 212.2 lb/hr CH_4 x 24 hr/day x vent days ÷ 2000 lb/ton x 21 GWP

2. Coal boiler CO_2 emissions estimated using GHG Mandatory Inventory Rule (MIR) equations:

Eq. C-3 for solid fuel: CO_2, tpy = 44/12 x tons coal x %C/100

%C estimated via regression of BTU/lb vs. %C from 2010 analytical data; assumed to be representative of coal from the same mine in baseline period:

%C = -4.8607 + 0.00613x, where x = BTU/lb

Eq. C-4 for liquid fuel: CO_2, tpy = 44/12 x fuel x CC x 0.001/0.91

CC estimated as 86.4% based on reference material

3. CH_4 and N_2O emissions estimated using (MIR) equation:

Eq. C-8: CH_4 or N_2O, tpy = 0.001 x Fuel x HHV x EF

where: HHV = 17.25 (coal)
0.138 (fuel oil)
0.001028 (nat gas)

CH_4 EF = 0.011 (coal)
0.0003 (fuel oil)
0.001 (nat gas)

N_2O EF = 0.0016 (coal)
0.0006 (fuel oil)
0.0001 (nat gas)

4. Gas boiler CO_2 emissions estimated using MIR equation:

Eq. C-2a for gaseous fuel: CO_2, tpy = 0.001 x scf gas x HHV x EF/0.91

where: HHV = .001050 MMBTU/scf (2007, 2008 data)
EF = 53.02

5. Diesel engine CO_2 emissions estimated using AP42 Ch.3, Sec. 4, Table 3.4-1:

CO_2, tpy = 165 lb/MMBtu x 0.141 MMBtu/gal x gal. fuel ÷ 2000 lb/ton

CH_4, tpy = (0.09 x .09) x 0.141 MMBtu/gal x gal. fuel ÷ 2000 lb/ton

6. CO_2, tons = [GPD] x [sp.gr.] x [% bicarb] x F x CY

where: GPD = 6,517,440 gal/day mine water
sp. gr. = 1.1348 (specific gravity of MW with 5% bicarb conc'n.)
% bicarb = 0.05 (5%)
F = 0.001092, based on: (8.34 lb/gal x (44 lb/mole CO_2 ÷ (2*84 lb/mole $NaHCO_3$)) ÷ 2000 lb/ton)
CY = 365 days/yr

Appendix B

Mine Emission Test Results

FMC

MINE VENT EMISSION TEST RESULTS

Airtech Environmental Services Inc. conducted an air emissions test program at its facility located in Granger, Wyoming on January 31 and March 12, 2012. The specific objective of the test program was to determine the concentrations of carbon dioxide (CO_2), carbon monoxide (CO), and methane from an injection well used as a Mine Vent, designated IW10. Typical open well head pressure of a vent well is <0.1 PSI.

IW10 Mine Vent Emissions Results

Test Parameters	**Run 1**	**Run 2**	**Run 3**	**Run 4**	**Run 5**	**Run 6**	
Date	01/31/12	01/31/12	01/31/12	03/12/12	03/13/12	03/13/12	
Start Time	11:40	12:55	14:30	15:54	8:00	11:00	
Stop Time	12:30	13:20	15:06	16:00	8:10	11:09	
Gas Conditions							
Wellhead Pressure, Open, PSI	1.9	1.7	1.5	1.2	0.2	0.09	
Temperature (°F)	47.7	49.4	49.6	50.1	49.8	50.6	
Volumetric Flow Rate (acfm)	460	418	411	379	179	138	
Volumetric Flow Rate (wscfm)	381	346	340	309	146	112	
Volumetric Flow Rate (dscfm)	376	342	336	305	144	111	
Moisture (%)	1.28	1.18	1.18	1.22	1.22	1.22	**Typical Vent Well lb/Vent Day**
Results							
Carbon Dioxide (ppmwv)	100	0.00	0.00	0.00	0.00	0.00	
Carbon Dioxide (lb/hr)	0.26	0.00	0.00	0.00	0.00	0.00	0.0
Carbon Monoxide (ppmwv)	2.02	1.79	1.96	1.54	1.61	1.65	
Carbon Monoxide (lb/hr)	0.00	0.00	0.00	0.00	0.00	0.00	0.0
Methane (ppmwv)	742,929	555,733	541,173	747,535	757,784	757,351	
Methane (lb/hr)	706.00	481.00	459.00	576.86	276.31	212.17	5092.1