UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

June 20, 2018

Mr. Wiley Smith
Shute Creek Facility
ExxonMobil Corporation
Kemmerer, Wyoming 83101

Re: Monitoring, Reporting and Verification (MRV) Plan for Shute Creek Facility

Dear Mr. Smith:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for the Shute Creek Facility as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted for the Shute Creek Facility as the final MRV plan. The MRV Plan Approval Number is 1002150-1. This decision is effective June 25, 2018 and appealable to EPA's Environmental Appeals Board under 40 CFR Part 78.

If you have any questions regarding this determination, please write to ghgreporting@epa.gov and a member of the Greenhouse Gas Reporting Program will respond.

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan ExxonMobil Shute Creek Treating Facility

June 2018

Contents

<u>**Appendices**</u>

This report summarizes the EPA's technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) Plan submitted by ExxonMobil for the Shute Creek Treating Facility.

1 Overview of Project

ExxonMobil produces sour gas -- natural gas containing significant amounts of hydrogen sulfide and carbon dioxide (CO_2) along with methane (CH_4) -- from the Madison Formation in the LaBarge field located in the southwestern corner of Wyoming. The producing field area is within the Green River Basin and the field is located due west of the Wind River Mountains along the Moxa Arch. Maps locating these features are shown in Figures 2.1 and 2.3 of the MRV plan. A stratigraphic column is also provided in Figure 2.2 of the plan.

The Madison formation at the LaBarge field has approximately 4,000 feet true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 1,000 square miles, making it one of the largest gas fields in North America. The H_2S and some of the CO_2 is injected into the Madison Formation via two injection wells, once the CH_4 is stripped from the produced gas.

The Madison is estimated to contain approximately 170 trillion cubic feet (Tcf) of raw gas and 20 Tcf of natural gas (CH_4). At current rates of production, the estimated remaining field life is over 100 years.

The Acid Gas Injection (AGI) system transports the acid gas stripped in the Selexol process under pressure through a pipeline to the two injection wells located at or near the Shute Creek Treatment Facility (SCTF). The AGI 3-14 and AGI 2-18 injection wells are described in the MRV Plan as geologically suitable for storage of the acid gas. The parameters of the petrophysical evaluation of the two wells are described in section 2.6.2 of the plan. Both AGI wells in LaBarge are permitted as UIC Class II wells. A map showing the location of the LaBarge field is provided in Figure 2.1 in the MRV plan.

ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. In the MRV plan, ExxonMobil states that it plans to continue injection until the year 2106. ExxonMobil forecasts the total volume of CO_2 stored over the modeled injection period to be approximately 37 million metric tons.

The MRV plan provides a description of the project, including the site setting, processes, and plans for injection operations. The description of the project is determined to be reasonable and provided the necessary information to comply with 40 CFR 98.448(a)(6). Both injection wells are permitted as UIC Class II wells and the UIC injection well identification numbers are provided in the MRV plan.

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

As part of the MRV Plan, the reporter must identify the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines maximum monitoring area as “the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile.” Subpart RR defines active monitoring area as “the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) the area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) the area projected to contain the free phase CO_2 plume at the end of year t + 5.” See 40 CFR 98.449.

Data collected from the wells, including

seismic data, and historical production and injection data. Following this, a history match of the reservoir model was conducted. History matching is the process of adjusting the model until it reproduces the past behavior of a reservoir, as closely as possible. The reservoir model is used to predict the size and location of the plume, as well as understand how the plume diameter changes, over time.

From this, ExxonMobil has defined the MMA as equal to or greater than the area expected to contain the free-phase CO_2 plume, until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one-half mile. Specifically, ExxonMobil defines this, as shown in Figure 3.4 in the MRV plan, as the maximum areal extent anticipated for the plume once it has reached stability (defined by the extent of the plume in July 2986), which is an 8.3-mile diameter plus the buffer zone of one-half mile.

The MMA, as it is defined in the MRV plan, is consistent with subpart RR requirements because the defined MMA accounts for the expected free phase CO_2 plume, based on modeling results, and incorporates the additional 0.5 mile or greater buffer. Therefore, the MMA defined by ExxonMobil in the MRV plan meets the requirements for subpart RR.

ExxonMobil has defined the AMA as the same boundary as the MMA, and states that monitoring within the AMA should encompass a sufficient area to detect any potential surface leaks. The MRV plan outlines the factors that ExxonMobil considered for defining the AMA boundary: (1) the lack of faulting in the MMA yields no vertical pathways for fluids to move vertically out of the storage reservoir (Madison formation) to shallower intervals; (2) the lack of faulting in the injection area does not create enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be Darcy flow from pore-to-pore; (3) the distance from the LaBarge production field area is large (30 miles) and formation permeability is generally low, which naturally inhibits flow aerially from injection site; and (4) the LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons for long geologic periods of time. In the MRV plan, ExxonMobil states that any injection fluids that may migrate outwards from the injection site to the larger LaBarge structure should be effectively trapped in the LaBarge structure over geological time.

The computational modeling used to delineate the MMA, as described in ExxonMobil's MRV plan, accounts for the existing operational and subsurface conditions at the site and supports a high level of confidence that monitoring over a sufficient area will be performed. Therefore, the designation of the AMA as the MMA is a reasonable approach.

The delineation of the MMA and AMA was determined to comply with 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV Plan are clearly and explicitly delineated and, are consistent with the definitions in 40 CFR 98.449.

3 Identification of Potential Surface Leakage Pathways

As part of the MRV Plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). ExxonMobil identified the following as potential leakage pathways in their MRV plan that required consideration: leakage from surface equipment (pipeline and wellhead), leakage through existing wells, leakage through faults and fractures, and leakage through the seal.

3.1 Leakage from Surface Equipment

ExxonMobil states that leakage from surface equipment is not likely due to the design of the AGI facilities. This is based on the continuous surveillance, facility design, and routine inspections of the surface equipment. Field personnel monitor the AGI facility continuously through the distributed controls system (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections rounds are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. ExxonMobil also relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSV's), which are set to trip closed if leakage is detected. The MRV plan states that this would eliminate any backflow out from the formation, minimizing leakage volumes.

ExxonMobil explains that this surface monitoring approach is in place, in large part, because of the presence of H_2S gas in the injected stream. Other monitoring methods include H_2S gas detectors around the AGI facility and well sites (alarm at 10 ppm) and the requirement for field personnel to wear H_2S monitors for safety reasons (alarm at 5 ppm). The MRV plan notes that the monitoring systems in place indicate that any leakage should be detected quickly.

ExxonMobil acknowledges that damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2 entrained in the acid gas; however, ExxonMobil states that at this concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm, and immediate action would be taken to stop the leak. As a result, ExxonMobil asserts that the magnitude of such a leak would likely be small. The plan states that the same techniques for detecting leakage from surface equipment will also detect any surface leakage.

The MRV plan provides a reasonable characterization of the likelihood of and the volume of a CO_2 leak that could be expected from surface equipment.

3.2 Leakage through Existing Wells

According to Section 4 of the MRV Plan, ExxonMobil asserts that leakage through abandoned oil and gas wells is not likely because there is no commercial production of oil or gas within the immediate area of the SCTF. No existing Madison penetrations or production occurs within the MMA, other than the AGI wells.

One well (Whiskey Butte Unit 1 operated by Wexpro Company), located approximately six miles from the AGI wells, was drilled to the Madison formation in 1974. However, it was ultimately plugged and abandoned in February 1992 and ExxonMobil asserts that it does not pose a risk as a leakage pathway.

The ExxonMobil MRV Plan states that continuous surveillance of injection parameters, routine inspections, and mechanical integrity testing (MIT) will reduce the risk of unplanned leakage from the AGI wells. Additionally, as applied to other surface equipment as well, visual inspections of the well sites are performed on a weekly basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors are located at the well sites which alarm at 10 ppm H_2S and would be triggered if a leak from the wellbore to the atmosphere occurred. SCSSV's and surface isolation valves are installed at the wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If mechanical integrity testing demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

Thus, the MRV plan provides a reasonable characterization of the likelihood of and the volume of a CO_2 leakage that could be expected from existing wells.

ExxonMobil explains that the risk from future drilling hazards are also minimal based on the geological model (presented in Figures 3.2 and 3.4 in the MRV Plan). The model shows that there is limited areal extent of the injection plume. From this, the geological model can be used to delineate areas that should be avoided during drilling. This model has also history-matched the AGI injection that has occurred to date, and suggests that future injection will closely follow the patterns resulting from the geological model simulation. Finally, ExxonMobil states that should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from the current AGI wells.

Based on this, the MRV plan provides a reasonable characterization of the likelihood of a CO_2 leakage that could be expected from potential future drilling hazards.

3.3 Leakage through Faults and Fractures

The MRV plan states that there is a lack of faulting, as observed on 2D seismic panels, around the AGI well sites. ExxonMobil considers leaks through faults or fractures to be highly improbable to nearly impossible because seismic surveys show no evidence of faulting or structuring around the AGI wells.

The MRV plan also states that the lack of significant natural fracturing in the Madison reservoir at and around the AGI well sites, in conjunction with active inspection of wellbore image logs within the AGI wells themselves, indicates that natural fractures do not exist. The MRV plan states there is no concern of reactivation of regional thrust faults from injection activities, and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field.

A study performed by the Wyoming State Geological Survey[1] examined the historical relationship between injection wells and earthquakes in Wyoming, and based on a review of small earthquakes at six sites, concluded that in five of the sites the earthquakes that occurred were most likely the result of natural causes and unrelated to injection well activities. The remaining site, showed no definitive correlation between injection well activity and seismic events, but it was determined that further research may be necessary at this site.

The study noted that one seismic event was observed near the LaBarge field (Area A in the referenced study). A magnitude 3.0 earthquake, with a reported depth of 2,297 feet, occurred on September 4, 1993 in this area. Prior to this seismic event, four disposal and six injection wells were active in this area. Injection activities in the LaBarge field continued in the years following the earthquake, and the amount of fluids injected increased in 1997 with the study noting no resultant seismic events. The amount of fluid injected decreased in 1998; however, disposal activities have continued and are still active, with the study noting no reported seismic events. The study concluded that the seismic event recorded on September 4, 1993 in this area was due to natural causes and not induced seismicity from fluid injection.

ExxonMobil worked with multiple service companies who provided a range of fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison Formations in the area. From this work, ExxonMobil explains that based on these fracture gradients, and a downhole fracture pressure of 12,167 psi (which corresponds to a surface injection pressure of approximately 5,500 psi), the injected acid gas will not initiate fractures in the confining zones of overlying strata. ExxonMobil also states that facility limits

[1] Larsen, M.C., and Wittke, S.J., 2014, Relationships between injection and disposal well activities and known earthquakes in Wyoming, from 1984 to 2013: Wyoming State Geological Survey Open File Report 2014-05.

exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation. From this the MRV plan asserts that the probability of fracturing is unlikely.

Thus, the MRV plan provides a reasonable characterization of the likelihood of and the volume of a CO_2 leakage that could be expected from through faults and fractures.

3.4 Leakage through the Formation Seal

The ultimate top seal to the Madison Formation is provided by the evaporitic sequences within the Thaynes Formation. The MRV plan states that leakage through the Thaynes Formation is highly improbable, as it is a proven natural seal due to the reservoirs existence in the first place – the gas has been trapped in the LaBarge structure over geologic time.

It is adequately and appropriately explained in the MRV plan that the rock that forms the natural seal is impermeable to He, a gas with a much smaller molecular volume than CO_2 and if the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. Other evidence given for the effectiveness of the seal is that all gas production shallower than the Thaynes is void of sour gas, while all gas production below it is enriched in sour gases. Thus, leakage through the seal is deemed unlikely.

In section 4.4 of the MRV plan; it is explained that natural flowage of the salty sediments below the Nugget formation likely occurs, however, ExxonMobil notes that this flowage does not disturb the sediments to the degree necessary to breach the reservoir seal of the Madison formation. Further, if this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison formation to the surface, the plan notes that natural gases trapped in the formation would have leaked into the atmosphere during the long course of geological time up to this point. The MRV plan asserts that because the gas remains trapped at pressure in the Madison formation, it must follow that any natural reactivation or flowage of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage through the formation seal.

ExxonMobil also states that any injection fluids that may migrate outwards from the area of the injection site to the larger LaBarge structure should be effectively trapped in the LaBarge structure over geological time, making leakage from lateral migration unlikely.

Thus, the MRV plan provides a reasonable characterization of the likelihood of and the volume of a CO_2 leakage that could be expected through or around the formation seal.

4 Strategy for Detecting and Quantifying Surface Leakage of CO2 and for Establishing Expected Baselines for Monitoring

Sections 5 and 6 of the MRV plan outline ExxonMobil's strategy for detecting and verifying potential subsurface leakage. ExxonMobil's approach primarily includes pressure monitoring of injection wells, well maintenance, monitoring of surface infrastructure, and field inspections (visual inspections and H_2S detection by staff). 40 CFR 98.448(a)(3) requires that an MRV Plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV Plan include a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. ExxonMobil's MRV plan adequately and appropriately describes both a strategy for detecting and quantifying any surface leakage of CO_2 based on the identification of potential leakage risks, as well as establishing baselines for monitoring against which potential suspected leaks can be identified, evaluated, and, if necessary, quantified.

Section 5 of the MRV plan describes ExxonMobil's strategy for leakage detection at the AGI injection site, which is part of the ongoing operations that continuously monitors and collects flow, pressure, temperature, and gas composition data in the distributed control system (DCS). In-field gas detectors to detect H_2S in the vicinity are an additional monitoring tool for the facility. The AGI wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, continuous injection well monitoring, well mechanical integrity tests (MITs), and DCS surveillance.

An Emergency Contingency Plan is in place and outlines a response procedure should leaks be detected. If there is report or indication of a leak from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-person control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. The MRV plan explains that the pressure from the system will be relieved to the flare, not vented, due to the dangerous composition of the gas.

The MRV plan states that any leakage quantification will consist of a methodology that will consist of modeling or engineering estimates based on operating conditions at the time of the leak, such as temperatures, pressures, volumes, hole size, etc.

Relying on the DCS infrastructure and operating procedures in place at the facility, ExxonMobil uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. ExxonMobil's approach to collecting baseline information is outlined below.

4.1 Visual Inspections

Field personnel conduct daily inspections of the AGI facilities and weekly inspections of the AGI well sites. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

4.2 H_2S Detection

The CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). The plan states that H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high of a concentration of H_2S, the plan notes that even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

4.3 Continuous Parameter Monitoring

The DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS and engineering and operations are alerted if a parameter is outside these set points. If a parameter is outside this allowable window, this will trigger further investigation to determine if the issue poses a leak threat.

4.4 Well Testing

On an annual basis, the AGI subsurface and wellhead valves are leak tested for mechanical integrity testing as required by the Wyoming Oil and Gas Conservation Commission (WOGCC). This consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, in-line inspections are conducted of the AGI flow lines using a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised.

Table 5.1 of the MRV plan provides general information on the leakage pathways, monitoring programs to detect leakage, and location of monitoring.

Based on this detection strategy, if results of the monitoring activities fall outside their normal predicted ranges, ExxonMobil will initiate an investigation to determine if a leak has occurred. Triggers provided in the MRV plan for leakage investigation include visual inspections, pressure deviation in injection wells, deviations in high and low set points, and triggering of H_2S monitors.

Pressure monitoring of injection wells, along with the historical operational and monitoring data determining the baseline, is an established way to detect leaks in injection wells. Annular pressures in injection wells should be close to zero in normal operating conditions because the annulus is isolated by the tubing and packer from injection fluids. Any higher pressure would indicate a potential leak in either the tubing or the packer and would trigger further investigation. Mechanical integrity testing is conducted on an annual basis for the injection wells.

It is noted in the MRV plan that ExxonMobil conducts daily field inspections at the facility. For visual inspections, the baseline would be normal visual conditions. The strategy to detect surface leakage also relies on the triggering of personal H_2S monitors worn by the staff. Any leakage of CO_2 would co-exist with some amount of this H_2S gas.

In Section 5.3 of the MRV Plan, ExxonMobil discusses how leaks will be quantified, using a combination of modeling, measurements and engineering estimates, as appropriate. Fugitive leakage would be detected and managed as an upset event and calculated for that event based on operating conditions at that time.

The MRV plan provides a reasonable approach to detecting and quantifying surface leakage of CO2 and for establishing expected baselines for monitoring, and complies with subpart RR.

5 Considerations Used to Calculate Site-Specific Variables for the Mass Balance Equation

A reporter who is not producing oil or natural gas is required to calculate the amount of CO_2 sequestered using equation RR-12 per 40 CFR 98.443(f)(2), which ExxonMobil appropriately proposes to use. The equation is:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 is the total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} is the total annual CO_2 mass injected (metric tons) in the well or group of wells covered by subpart RR in the reporting year.

CO_{2E} is the total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} is the total CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W.

ExxonMobil adequately and appropriately explains its approach to calculating each of these variables in Section 7 of the MRV Plan.

5.1 Calculation of Total Annual Mass Injected

ExxonMobil will determine the amount of CO_2 injected by using volumetric flow meters which are used to measure the injection volumes at each well. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected. Equation RR-6 will be used to aggregate injection data for wells 2-18 and 3-14.

ExxonMobil's proposed approach for calculating the total annual mass injected is acceptable for the subpart RR requirements.

5.2 Calculation of Total Annual Mass Emitted by Surface Leakage

For reporting of the total annual CO_2 mass sequestered under subpart RR, potential surface leaks must be accounted for in the mass balance equation. Pursuant to 40 CFR 98.448(a)(2), an MRV Plan must describe the likelihood, magnitude, and timing of surface leakage of CO_2 through potential pathways. Subpart RR also requires that the MRV plan identify a strategy for establishing a baseline for monitoring CO_2 surface leakage, pursuant to 40 CFR 98.448(a)(4).

ExxonMobil discuss surface leakage and equipment leakage together in their MRV plan, since the proposed methods for both detection and emissions estimation will be based on the same techniques. This is discussed in Section 5.3. The plan's approach is reasonable for estimating potential emission from potential surface leakage given the likelihood, magnitude, and timing of surface leakage described above.

5.3 Calculation of Total Annual Mass Emitted as Equipment Leakage or Vented Emissions

ExxonMobil will estimate the mass of CO_2 emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak.

ExxonMobil asserts that there will be no CO_2 emissions from venting due to the high H_2S concentration of the injected gas; blowdown emissions are sent to the flares and are reported under subpart W for the gas plant. For this reason, ExxonMobil states that it is not appropriate to conduct a leak survey in the AGI operations due to the components being unsafe to monitor with field personnel because it would require the individual to wear a full-face respirator supplied to breathing air, which would make completion of a leak survey very difficult. Due to the high H_2S concentration of the AGI fluids, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface and/or equipment leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time.

This approach is reasonable for estimating potential emission from equipment leakage or vented emissions.

6 Summary of Findings

The subpart RR MRV Plan for the ExxonMobil Shute Creek Treating Facility meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV plans, are summarized below, along with a summary of relevant provisions in ExxonMobil's MRV Plan.

Subpart RR MRV Plan Requirement	ExxonMobil MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV Plan describes the MMA and AMA. The MMA is delineated as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one-half mile and the AMA is defined as the same as the MMA. The MMA and AMA delineations take into account site characterization and reservoir modeling along with pressure management considerations.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV Plan identifies and evaluates potential surface leakage pathways. The MRV Plan identifies the following most likely potential pathways: leakage from surface equipment (pipeline and wellhead), leakage through existing wells, leakage through faults and fractures, and leakage through the seal. The MRV Plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. ExxonMobil determined that leakage pathways are highly improbable to minimal at the Shute Creek facility and it is very unlikely that potential leakage conduits would result in significant loss of CO_2 to the atmosphere.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 5 of the MRV Plan describes how the facility would detect CO_2 leakage to the surface, such as monitoring of existing wells, field inspections, and pressure modeling and monitoring. The monitoring strategy is summarized in Table 5.1 of the MRV Plan. Section 5 of the MRV Plan also describes how surface leakage would be quantified.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 6 of the MRV Plan describes the baselines against which monitoring results will be compared to assess potential surface leakage.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 7 of the MRV Plan describes ExxonMobil's approach to determining the amount of CO_2 sequestered using the subpart RR mass balance

	equation, including as related to calculation of total annual mass emitted as equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 in the MRV Plan provides well identification numbers for each well. The MRV Plan specifies that injection wells are permitted as UIC Class II.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	The MRV Plan states that the Shute Creek Facility will have been following most of the monitoring procedures outlined in this plan since 2005. ExxonMobil will begin implementing this MRV plan beginning January 1, 2018.

Appendix A: Final MRV Plan

ExxonMobil Shute Creek Treating Facility Subpart RR Monitoring, Reporting and Verification Plan

February 2018

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Introduction

Exxon Mobil Corporation (ExxonMobil) operates two acid gas injection (AGI) wells in the Madison reservoir located near LaBarge, Wyoming for the primary purpose of acid gas disposal with a subsidiary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. ExxonMobil has developed this monitoring, reporting, and verification (MRV) plan in accordance with 40 CFR §98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for the monitoring, reporting and verification of geologic sequestration in the Madison reservoir during the injection period. This plan meets the requirement in §98.440(c)(1).

This MRV plan contains ten sections:

- Section 1 contains facility information.

- Section 2 contains the project description. This section describes the geology of the LaBarge Field, the history of the LaBarge field, an overview of the injection program and process, and provides the planned injection volumes. This section also demonstrates the suitability for secure geologic storage in the Madison reservoir.

- Section 3 contains the delineation of the monitoring areas.

- Section 4 evaluates the potential leakage pathways and demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

- Section 5 provides information on the detection, verification, and quantification of leakage. Leakage detection incorporates several monitoring programs including routine visual inspections, H_2S alarms, mechanical integrity testing of the well sites, and continuous surveillance of various parameters. Detection efforts will be focused towards managing potential leaks through the injection wells and surface equipment due to the improbability of leaks through the seal or faults and fractures.

- Section 6 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO_2 leakage.

- Section 7 provides the site specific modifications to the mass balance equation and the methodology for calculating volumes of CO_2 sequestered.

- Section 8 provides the estimated schedule for implementation of the MRV plan.

- Section 9 describes the quality assurance program.

- Section 10 describes the records retention process.

1.0 Facility Information

i) Reporter number: 523107
The AGI wells report under the Shute Creek Treating Facility (SCTF) Greenhouse Gas Reporting Program Identification number, which is: 523107.

ii) Underground Injection Control (UIC) Permit Class: Class II
The Wyoming Oil and Gas Conservation Commission (WOGCC) regulates oil and gas activities in Wyoming. Both AGI wells in LaBarge are classified as UIC Class II wells.

iii) UIC injection well identification numbers:

Well Name	AGI 2-18	AGI 3-14
Well Identification Number	4902321687	4902321674

2.0 Project Description

This section describes the planned injection volumes, environmental setting of the LaBarge Field, injection process, and reservoir modeling.

2.1 Geology of the LaBarge Field

The LaBarge field area is located in the southwestern corner of Wyoming, contained in Lincoln and Sublette counties. The producing field area is within the Green River Basin and the field is located due west of the Wind River Mountains along the Moxa Arch (Figure 2.1).

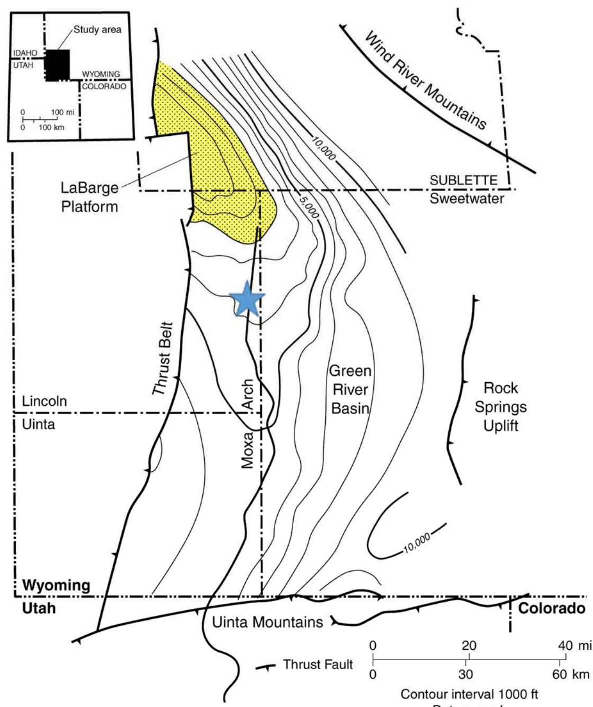

Figure 2.1 Location Map of the LaBarge Field, Wyoming. The injection area is denoted by the blue star.

2.2 Stratigraphy of the Greater LaBarge Field Area

The western region of Wyoming has been endowed in a very rich and prolific series of hydrocarbon reservoirs. Hydrocarbon production has been established or proven from a large number of stratigraphic intervals around Wyoming, ranging from reservoirs from Cenozoic to Paleozoic in age. Figure 2.2 shows a complete stratigraphic column applicable to the Greater Green River Basin in western Wyoming.

For the LaBarge field area, specifically, commercially producible quantities of hydrocarbons have been proven in the following intervals:

- Upper Cretaceous Frontier formation
- Lower Cretaceous Muddy formation
- Permian Phosphoria formation
- Lower Jurassic Nugget formation
- Pennsylvanian Weber formation
- Mississippian Madison formation

2.3 Structural Geology of the LaBarge Field Area

The LaBarge field area lies at the junction of three regional tectonic features: the Wyoming fold and thrust belt to the west, the north-south trending Moxa Arch that provides closure to the LaBarge field, and the Green River Basin to the east. On a regional scale, the Moxa Arch delineates the eastern limit of several regional north-south thrust faults that span the distance between the Wasatch Mountains of Utah to the Wind River Mountains of Wyoming (Figure 2.3).

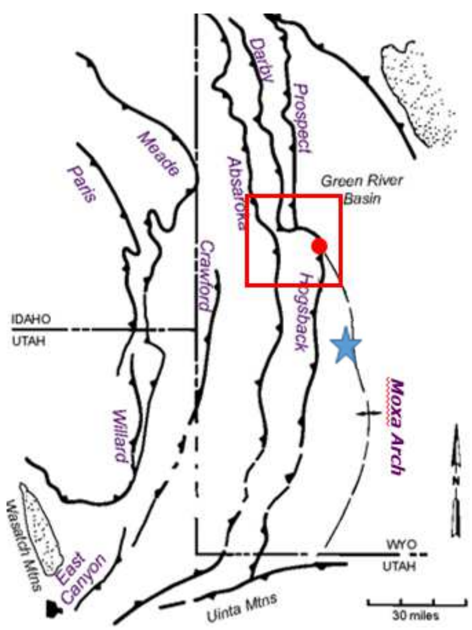

Figure 2.3 Schematic map showing location of Moxa Arch, regional thrust faults. The LaBarge field area is denoted by the red box and the approximate injection area is denoted by the blue star.

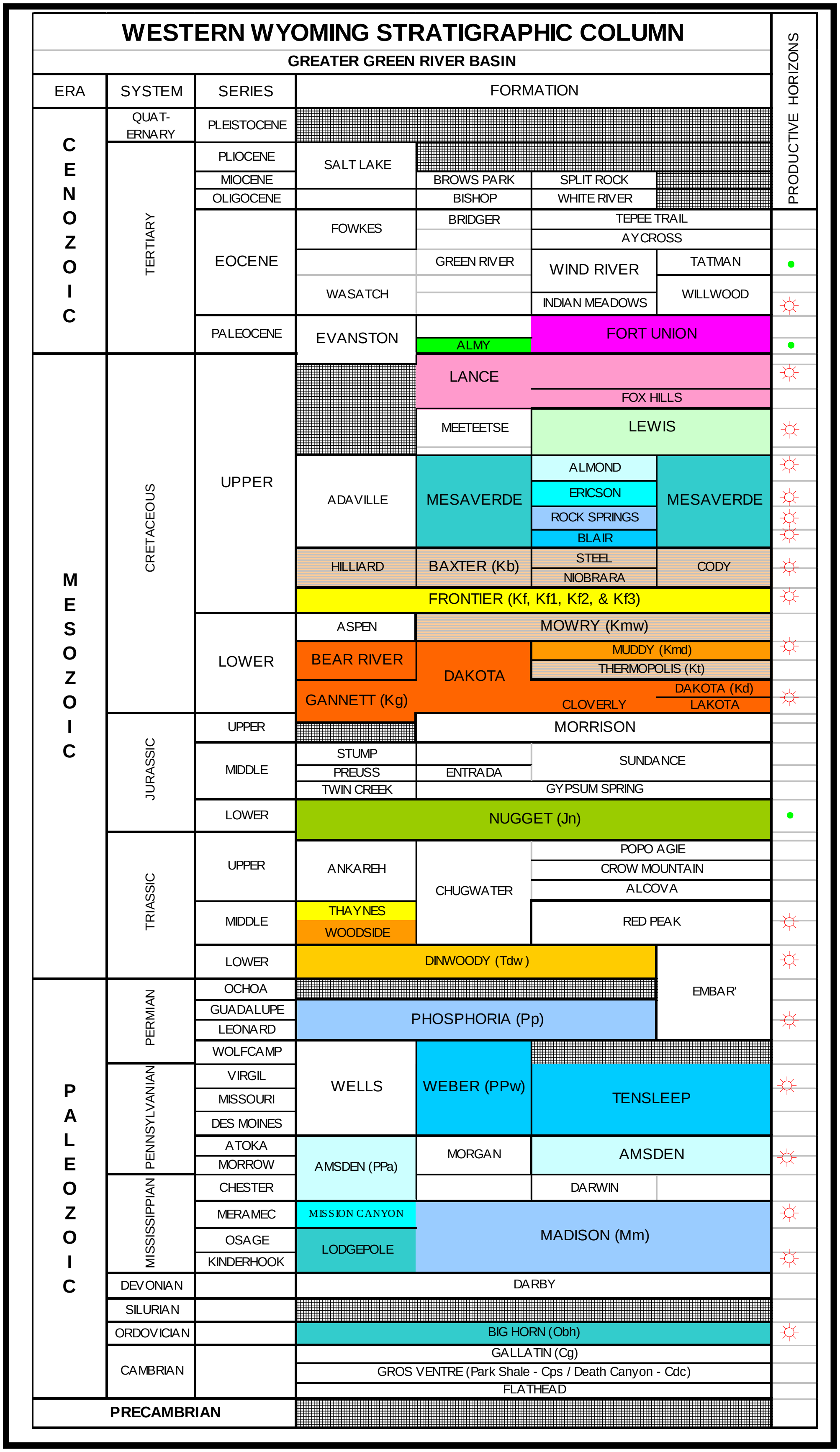

Figure 2.2 Generalized Stratigraphic Column for the Greater Green River Basin, Wyoming

The historical evaluation of structural styles at LaBarge has revealed that three principal styles of structuring have occurred in the area:

- Basement-involved contraction
- Deformation related to flowage of salt-rich Triassic strata
- Basement-detached contraction.

2.3.1 Basement-involved Contraction Events

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinal features being formed along the western edge of the LaBarge field area (Figure 2.3). These regional monoclinal features have been imaged extensively with 2D and 3D seismic data, and are easily recognizable on these data sets (Figure 2.4). At a smaller scale, the monoclinal features set up the LaBarge field structure, creating a hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section.

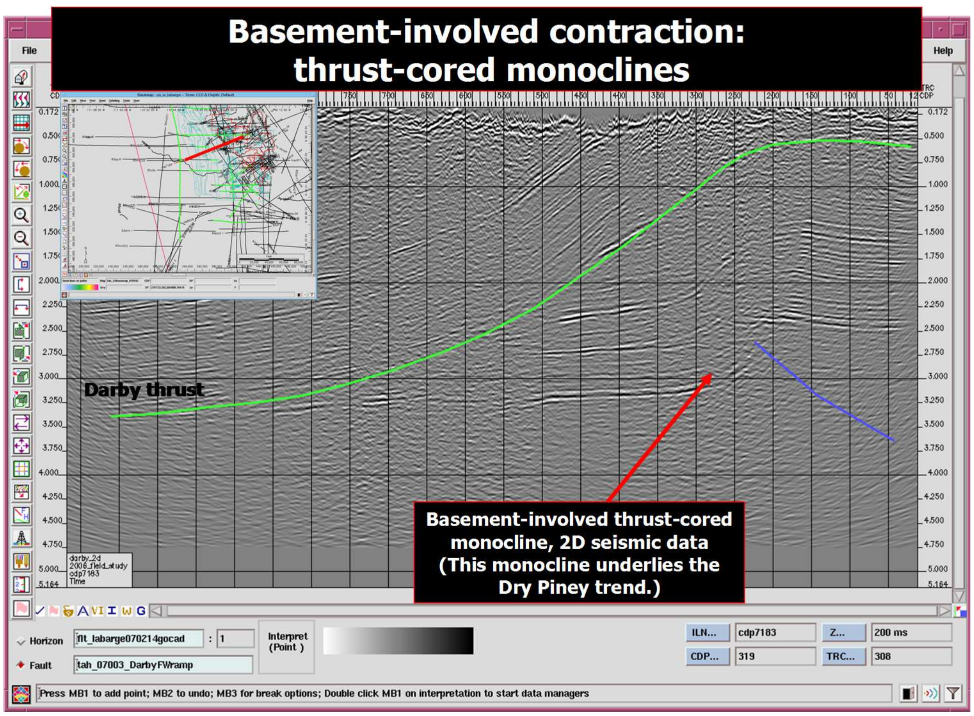

Figure 2.4 Example of thrust-cored monoclinal feature interpreted from 2D seismic data. The thrust-cored feature is believed to be a direct product of basement-involved contractional events.

2.3.2 Deformation of Flowage from Triassic Salt-rich Strata

The second most common style of deformation in the LaBarge field area is the result of flowage from Triassic strata that contain significant amounts of salt. These Triassic sediments have been observed in outcrop to be comprised of interbedded salt and siltstone intervals. At LaBarge, it is not typical to observe thick, continuous sections of pure salt, but rather the interbedded salt and siltstone sections. The 'salty sediments' of this interval have been determined to later evacuate and/or flow, which results in local structural highs being developed around these areas. Figure

2.5 shows two seismic lines showing the Triassic salt-rich sediments and the structuring. The salt-induced local structural features generated via salt evacuation can and do create small, local hydrocarbon traps associated with these sediments. These smaller, localized structures are of a much smaller scale than the main monoclinal hydrocarbon trap of the larger LaBarge field.

The active deformation behavior of these Triassic sediments has been empirically characterized through the drilling history of the LaBarge field. Early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. Subsequent drilling at LaBarge has necessitated using thicker-walled casing strings to combat the sediment flowage problems.

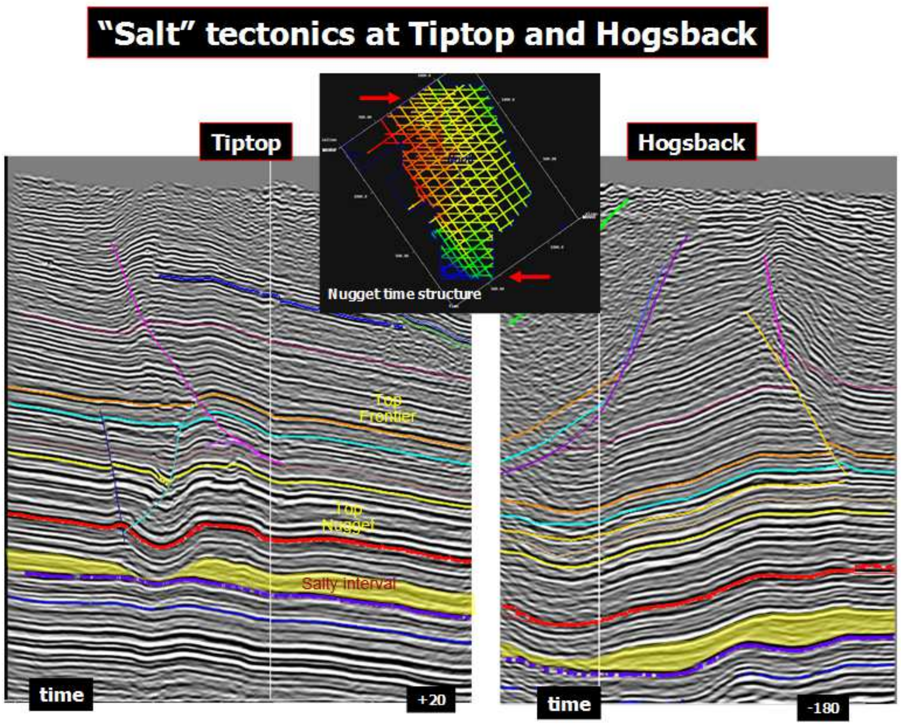

Figure 2.5 Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area (Data courtesy of CGG and WesternGeco)

2.3.3 Basement-detached Contraction

The third main structural style observed at LaBarge field is those resultant from basement-detached contraction. These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. Detachment and contraction along the basement typically creates three types of structural features:

- Regional scale thrust faults
- Localized, smaller scale thrust faults
- Reactivation of Triassic salt-rich sediments resulting in local structural highs (section 2.3.2.).

The basement-detached contraction features typically occur at a regional scale. The subsurface structural features formed through these contractional events are the same size or larger than the greater LaBarge field area. Very large faults are usually associated with these subsurface features, albeit that the reactivation of Triassic salt sediments which can result in additional localized structuring in the area (section 2.3.2).

2.3.4 Faulting and Fracturing of Reservoir Intervals

Reservoir permeability has been observed to increase with the presence of small-scale faults and fractures in almost all of the productive intervals of LaBarge field. Micro-fractures have been observed in core and on formation micro imager (FMI) logs. The fractures seen in the available core are typically filled with calcite, in general.

Empirically, reservoir permeability and increased hydrocarbon productivity have been observed in wells/penetrations that are correlative to areas located on or near structural highs or fault junctions. These empirical observations tend to suggest that these areas have a much higher natural fracture density than others areas or have a larger proportion of natural fractures that are open and not calcite filled. Lack of faulting in an area, as is observed in the area of the existing AGI wells at LaBarge, tends to yield reservoir permeability that is dominated only by matrix or pore-to-pore flow that is generally inhibitive to fluid flow in the subsurface over long distances.

2.3.5 LaBarge Field Structure and Gas Resource of the Madison Formation

Structural closure on the Madison formation at the LaBarge field is quite large, with approximately 4,000' true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 1,000 square miles making it one of the largest gas fields in North America.

The Madison is estimated to contain approximately 170 trillion cubic feet (TCF) of raw gas and 20 TCF of natural gas (CH_4). At current rates of production, the estimated remaining field life is over 100 years. Spatially, the Madison injection wells have been located at or immediately adjacent to the SCTF, over 40 miles to the southeast from the main LaBarge production areas.

2.4 History of the LaBarge Field Area

The LaBarge field was initially discovered in 1920 with the drilling of a shallow oil producing well. The generalized history of the LaBarge field area is as follows:

- 1907 Oil seeps observed near LaBarge, surface mapping of Tip Top anticline
- 1920 Texas Production Company drills shallow Hilliard sandstone discovery (10 BOPD)
- 1940's General Petroleum (Mobil) explores LaBarge area, surface and seismic mapping

- 1951 Tip Top Field discovered by G.P. (Frontier SS @ 1.8 MCFD, Nugget SS @ 266 BOPD)
- 1952 Belco discovers Frontier gas at Big Piney and LaBarge
- 1954 Belco commits gas to Pacific NW Pipeline, 33 SI gas wells
- 1956 Pacific NW Pipeline completed
- 1956-64 Active drilling of Frontier wells (structural traps)
- 1962 Mobil discovers Madison LS gas at Tip Top, chooses not to develop
- 1970 Exxon evaluates LaBarge area
- 1975-84 2nd major phase of Frontier drilling (stratigraphic traps)
- 1980 Section 29 of Oil Windfall Tax Act for tight gas sands passed (expired 01/01/94)
- 1981 Exxon discovers Madison gas on Lake Ridge Unit (LRU 1-03)
- 1986 First sales of Exxon Madison gas
- 1992 Wyoming Oil & Gas Commission approves 160 acre spacing for Frontier
- 1989-95 Chevron, Enron, PG & E, and Mobil actively drill Frontier targets
- 1999 Exxon and Mobil merge

Historically, Exxon held and operated the Lake Ridge and Fogarty Creek areas of the field, while Mobil operated the Tip Top and Hogsback field areas (Figure 2.6). The heritage operating areas were combined in 1999, with the merger of Exxon and Mobil to form ExxonMobil, into the greater LaBarge operating area. In general, heritage Mobil operations were focused upon shallow sweet gas development drilling while heritage Exxon operations focused upon deeper sour gas production.

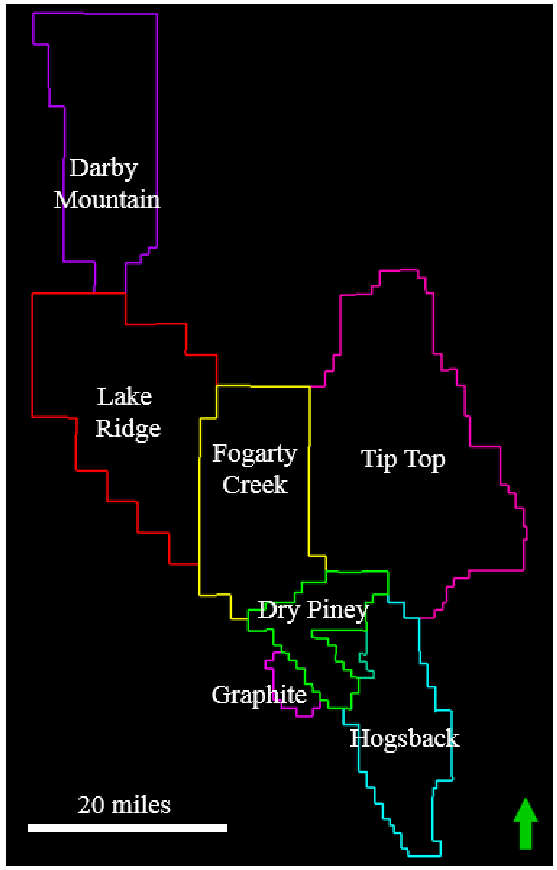

Figure 2.6 Unit map of the greater LaBarge field area

2.5 Initial Discovery of Gas and Early Commercial Production at LaBarge

ExxonMobil's involvement in LaBarge originates in the 1960's with Mobil's discovery of gas in the Madison carbonate formation. The Madison discovery, however, was not commercially developed until much later in the 1980's following Exxon's Madison gas discovery on the Lake Ridge Unit. Subsequently, initial commercial gas production at LaBarge was first established in the Frontier formation, while commercial oil production was established in the Nugget formation.

Gas production from the Madison formation was initiated in 1986 after the start-up of the SCTF, which expanded capacity to handle Madison gas. The total gas in-place for the Madison formation at LaBarge is in excess of 167 TCF gross gas and is a world-class gas reserve that was felt to be economically attractive for production.

2.6 Acid Gas Injection Program History at LaBarge

The Madison formation, once commercial production of gas was established, was found to contain relatively low methane (CH_4) concentration and high carbon dioxide (CO_2) content. The average properties of Madison gas are:

- 21% CH_4
- 66% CO_2
- 7% nitrogen (N_2)
- 5% hydrogen sulfide (H_2S)
- 0.6% helium (He)

Due to the abnormally high CO_2 and H_2S content of Madison gas, the CH_4 was stripped from the raw gas stream leaving a very large need for disposal of the CO_2 and H_2S that remained. For enhanced oil recovery projects (EOR), CO_2 volumes have been historically sold from LaBarge to offset oil operators operating EOR oilfield projects. Originally, the SCTF contained a sulfur recovery unit process to transform the H_2S in the gas stream to elemental sulfur. In 2005, the SRU's were decommissioned to debottleneck the plant and improve plant reliability. This created a need to establish reinjection of the H_2S, and entrained CO_2, to the subsurface.

2.6.1 Geological Overview of AGI Program

Sour gas of up to 66% CO_2 and 5% H_2S is currently produced from the Madison formation at LaBarge. The majority of produced CO_2 is currently being sold by ExxonMobil to other oilfield operators and is being used in EOR projects in the region. The sold volume however, does not equal the total produced CO_2 and H_2S volumes, thereby requiring disposal.

ExxonMobil has pursued the AGI program as a safe and reliable method to re-inject the acid gas into the Madison formation below the field GWC. Gas composition is based on plant injection needs, and will vary between 35 - 50% CO_2 and 50 - 65% H_2S. The gas is injected at a depth of 17,500 feet below the surface and approximately 43 miles away from the main producing areas of LaBarge. Figure 2.7 is a schematic diagram illustrating the AGI program at LaBarge.

2.6.2 Reservoir Quality of Madison Formation in AGI Wells

The existing AGI wells were successfully drilled, logged, and evaluated prior to injection commencement. Figure 2.8 is a schematic of two of the AGI wells (3-14 and 2-18). Petrophysical evaluation of these wells indicate that Madison limestone and dolomite sequences were penetrated, as expected. Total porosity ranges of the limestone sequences were determined to be between 0% and 5%, while the dolomite sequences were found to be up to 20% total porosity. Injection fall-off testing indicated that both wells exhibit greater than 2000 millidarcy-feet (md-ft) of permeability-height within the injection section. Figure 2.9 shows a table summarizing the reservoir properties determined from the 3-14 and 2-18 wells.

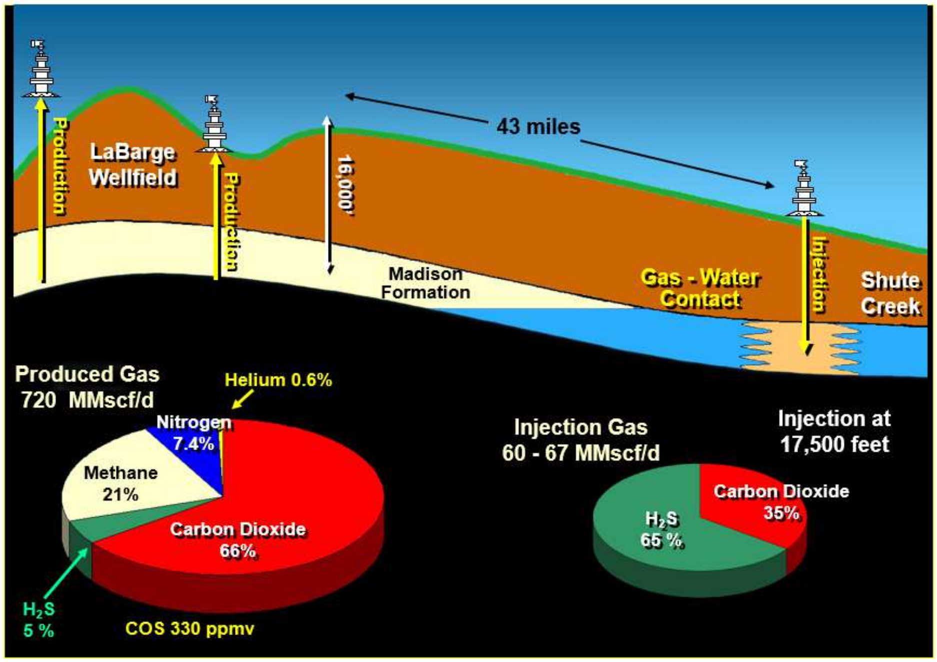

Figure 2.7 Schematic illustration of AGI injection program as currently used at LaBarge

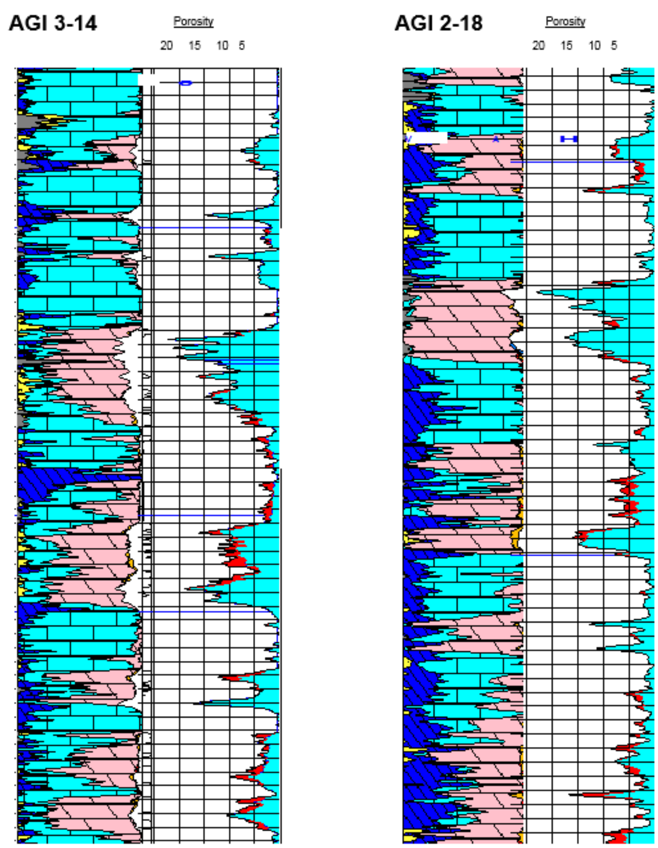

Figure 2.8 Well log sections from the AGI 3-14 and 2-18 injections wells across the Madison formation.

AGI WELLS

	PRE-DRILL	ACTUAL	
		AGI 3-14	AGI 2-18
Net Pay (ft)	210	240	220
Avg ϕ (%)	7%	10%	9%
Avg k (md)	9	9	12
kh (md.ft)	1900	2300*	~2700*
Skin	0	-4.1*	-4.5*

* From injection / falloff test analysis

Figure 2.9 Average reservoir properties of the two AGI wells.

From Figure 2.9, the parameters tabulated include:

- *Net pay:* Madison section that exceeds 5% total porosity.
- *Phi (ϕ):* Total porosity; the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements.
- *K:* Air permeability, which is measured in units of darcy; a measure of the ability of fluids to move from pore to pore in a rock. Note that the measure of darcy assumes linear flow (i.e. pipe shaped).
- *Kh:* Millidarcy-feet, which is a measure of the average permeability calculated at a 0.5 foot sample rate from the well log accumulated over the total net pay section encountered.
- *Skin:* Relative measure of damage or stimulation enhancement to formation permeability in a well completion. Negative skin values indicate enhancement of permeability through the completion whereas positive values indicate hindrance of permeability or damage via the completion.

2.6.3 Seismic Expression of Madison Formation at AGI Well Location

Seismic expression of the Madison formation at the injection location indicates that the injection wells are located on the plunging crest of the Moxa Arch with little to no structuring observable on the seismic data. Faulting is also not indicated by the seismic data. Figure 2.10 shows example lines from the AGI injection area at four times vertical exaggeration.

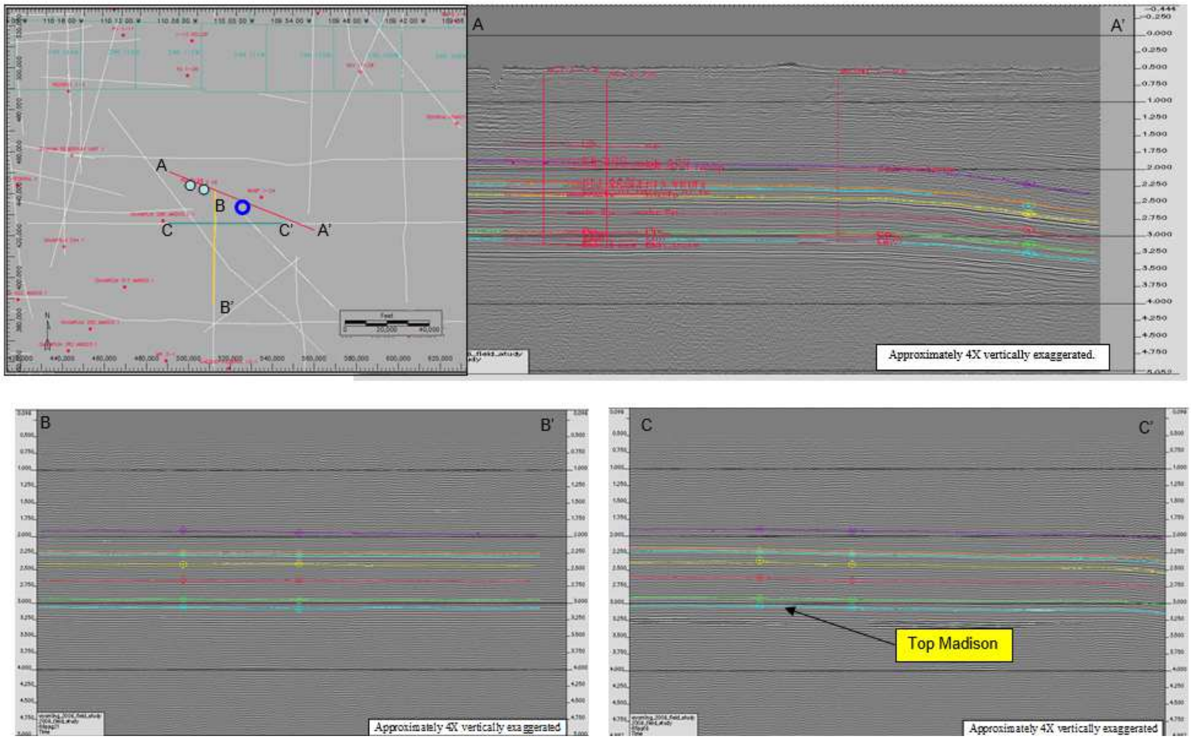

Figure 2.10 Seismic traverses around AGI injection well locations showing no evidence of faulting or structuring around the AGI wells

2.7 Description of the Injection Process

The AGI facility was commissioned for eliminating the Claus Sulfur Recovery Units bottleneck, reducing plant downtime, and reducing operating costs. The purpose of AGI is to take the H_2S and some of the CO_2 removed from the produced raw gas and inject it back into the Madison reservoir. Production of raw gas and injection of acid gas are out of and into the Madison Formation. The Madison reservoir fluid contains very little CH_4 and He at the lower injection locations under SCTF, where the AGI wells are located. Thus, there is no concern of contaminating the production from the LaBarge well field 43 miles away.

The AGI system transports the acid gas stripped in the Selexol process under pressure through a pipeline to two underground wells that are geologically suitable for storage of the acid gas. There are three parallel compressor trains. Two trains are required for full capacity; the third train is a spare. The low pressure feed from the Selexol process enters the first stage suction and is compressed through four stages of compression. The high pressure acid gas from the Selexol process requires only three stages of compression. The fourth stage discharge acid gas must be condensed prior to pumping to prevent damage from vapors. Fourth stage discharge acid gas is cooled in three heat exchangers prior to entering the pump. Dense phase aerial coolers are located downstream of the pumps; they remove heat generated by pumping and increase the density of the fluid. The liquid H_2S/CO_2 is commingled downstream of the dense phase coolers and divided to the two injection wells (3-14 and 2-18). The approximate stream composition being injected is 50 - 65% H_2S and 35 - 50% CO_2.

Each injection well has a dedicated six-inch carbon steel pipeline. The length of pipeline from the AGI battery limit to the injection wells is about:

- 3,200 feet to AGI 3-14
- 12,400 feet to AGI 2-18

The AGI flow lines are buried with seven feet of cover. Heat tracing is provided for the aboveground portions of the lines to prevent the fluid from cooling to the point where free water settles out. Free water and liquid H_2S/CO_2 form acids, which could lead to corrosive conditions. Additionally, the gas is dehydrated before it enters the flow line, reducing the possibility of free water formation, and the water content of the gas is continuously monitored. The liquid H_2S/CO_2 flows via the injection lines to two injection wells. The total depth of each well is about:

- 18,015 feet for AGI 3-14
- 18,017 feet for AGI 2-18.

2.8 Planned Injection Volumes

The below graph is a long-term injection forecast through the life of the injection project. It is based on historic and predicted data. It is important to note that this is just a forecast; actual injection volumes will be collected, calculated, and reported as required by Subpart RR. Additionally, the volumes provided below are the total amount of gas to be injected, not just the CO_2 portion. ExxonMobil forecasts the total volume of CO_2 stored over the modeled injection period to be approximately 37 million metric tons.

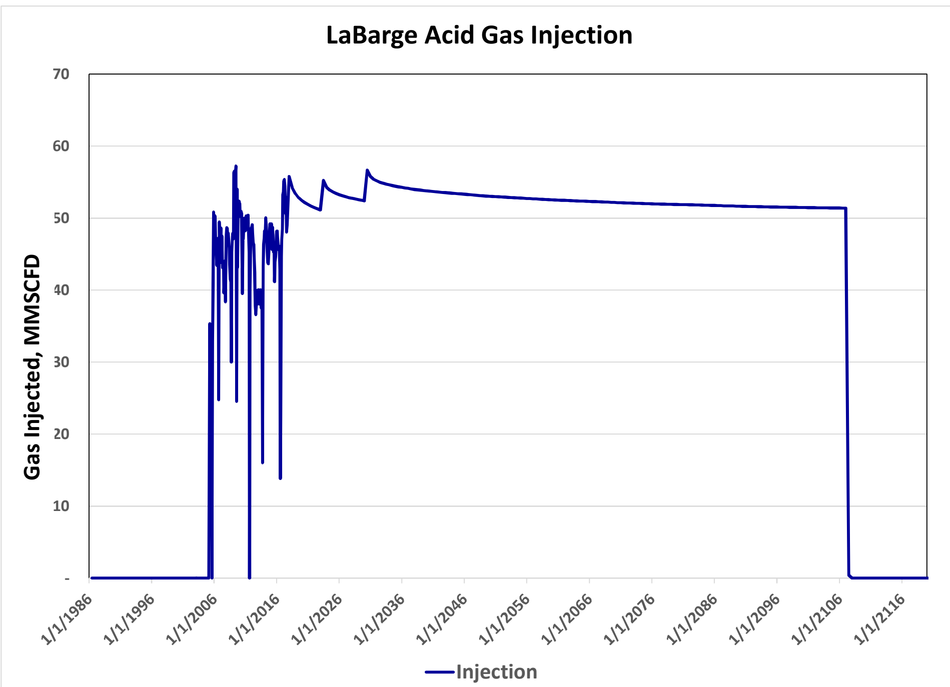

Figure 2.11 – Planned Injection Volumes

3.0 Delineation of Monitoring Area

3.1 Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the acid gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 0.5%. A gas saturation of 0.5% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison formation.

After injecting 0.2 TCF by year-end 2017, the estimated acid gas plume size is approximately 15,000 feet in diameter (2.84 miles) (see Figure 3.1). With continuing injection of an additional 1.7 TCF through year-end 2106, at which injection is expected to cease, the plume size is expected to grow to approximately 36,000 feet in diameter (6.82 miles) (see Figure 3.2). Figure 3.3 shows how the predicted plume average diameter is expected to change over time. The model was run through July 2986 to assess the potential for expansion of the plume after acid gas injection ceases. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. Expansion of the plume to a diameter of approximately 42,000 feet (7.95 miles) occurs by the year 2500 as the gas plume settles due to gravity segregation and dispersion. The plume is expected to continue settling, with a modeled plume size of approximately 44,000 feet (8.33 miles) by July 2986, 1000 years after production of the LaBarge field started and over 800 years after injection was shut-in. At this point, the rate of movement of the free-phase gas plume has decreased to less than four feet per year, demonstrating plume stability. Therefore, the MMA will be defined by Figure 3.4, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume in July 2986, which is an 8.3-mile diameter) plus the buffer zone of one-half mile.

3.2 Active Monitoring Area (AMA)

ExxonMobil proposes to define the AMA as the same boundary as the MMA. The following factors were considered in defining this boundary:

- Lack of faulting in the MMA yields no vertical pathways for fluids to move vertically out of the Madison to shallower intervals.
- Lack of faulting in the injection area does not create enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be darcy flow from pore to pore.
- Distance from the LaBarge production field area is large (30 miles) and formation permeability is generally low which naturally inhibits flow aerially from injection site.

- The LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons for large geologic periods of time. There is no reason to believe that any injection fluids that may migrate outwards from the injection site to the larger LaBarge structure would not also be effectively trapped at the LaBarge structure over geological time.

The purpose of the AMA is to allow for a practical and cost-effective monitoring program throughout the life of the project. Because there are no probable leakage pathways in the maximum monitoring area, besides surface equipment which is extensively monitored, ExxonMobil believes it is appropriate to define the AMA as the same boundary as the MMA. Additionally, due to the high H_2S content of the injected gas stream, monitoring of leaks is essential to operations and personnel safety, so a full-scale monitoring program has already been implemented at the AGI sites, as will be discussed below.

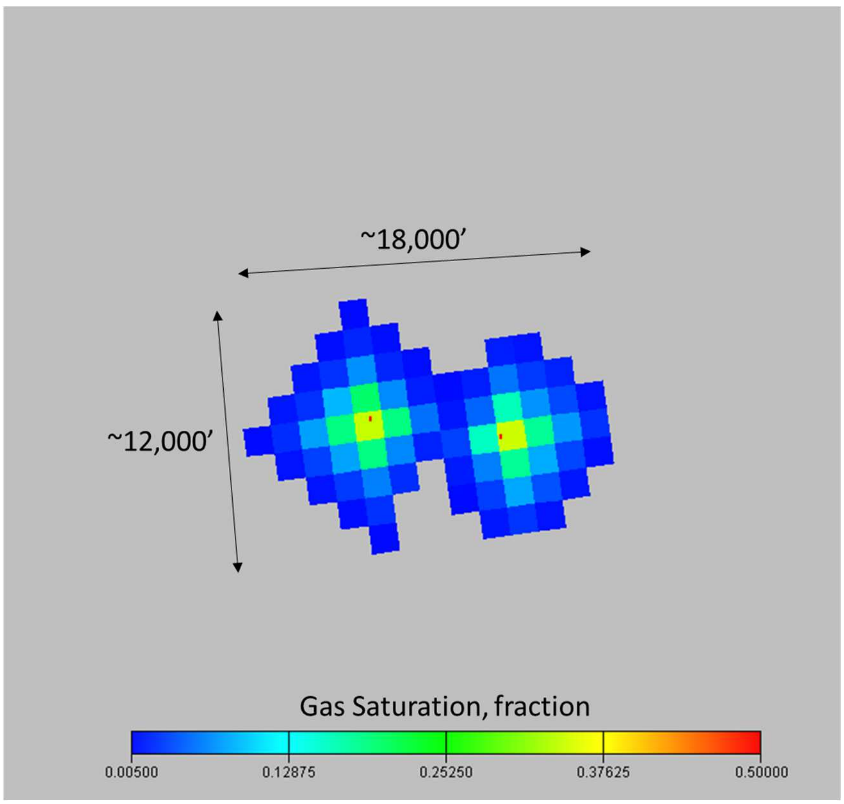

Figure 3.1 – AGI Gas Saturations at Year-end 2017

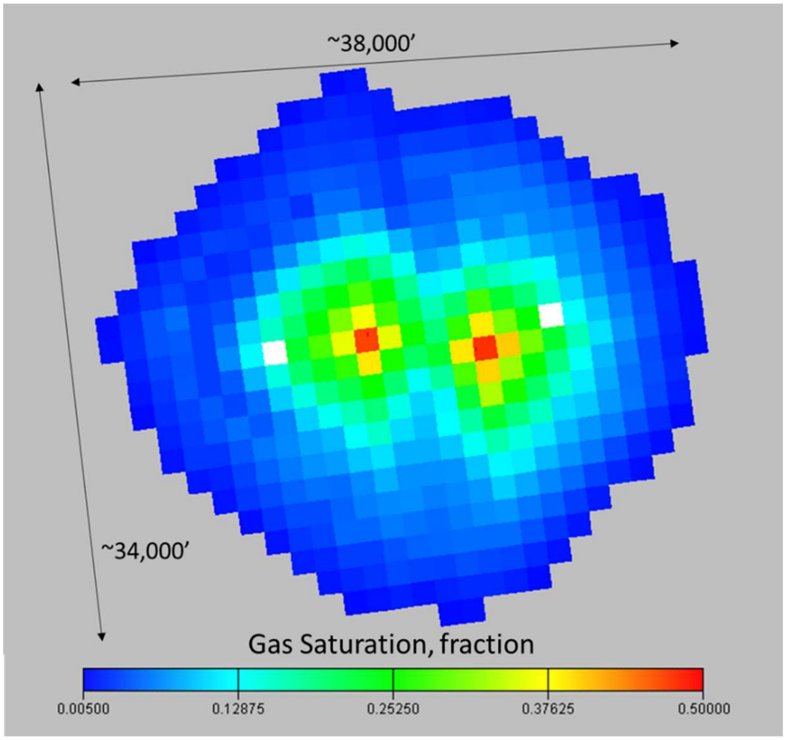

Figure 3.2 – AGI Gas Saturations at Year-end 2106

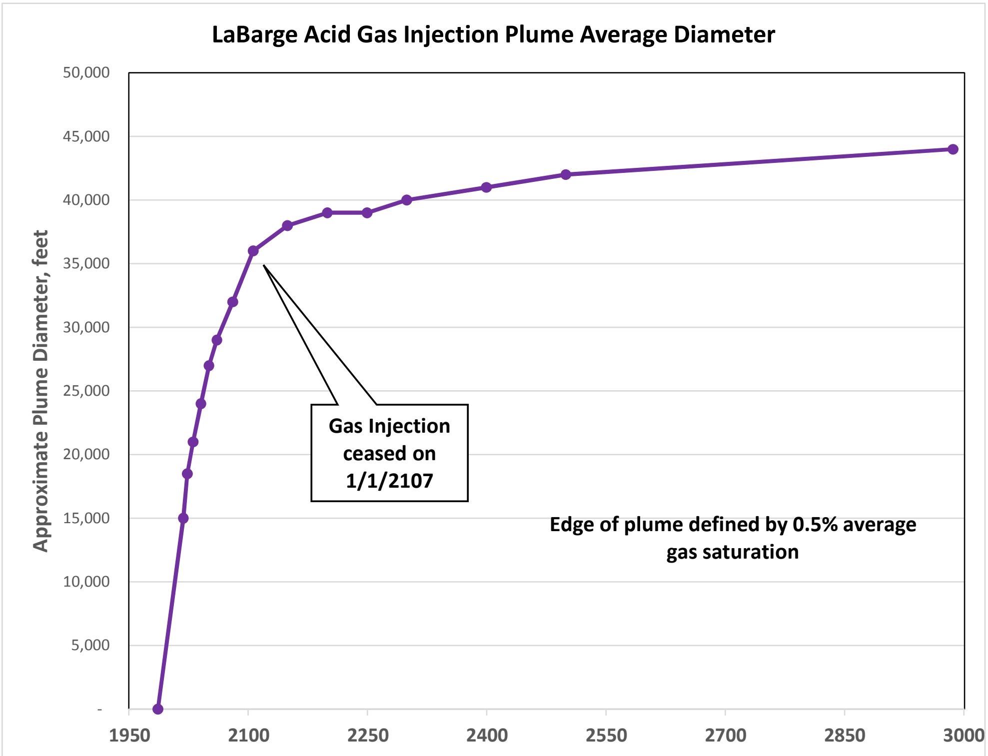

Figure 3.3 – Predicted LaBarge AGI Plume Diameter

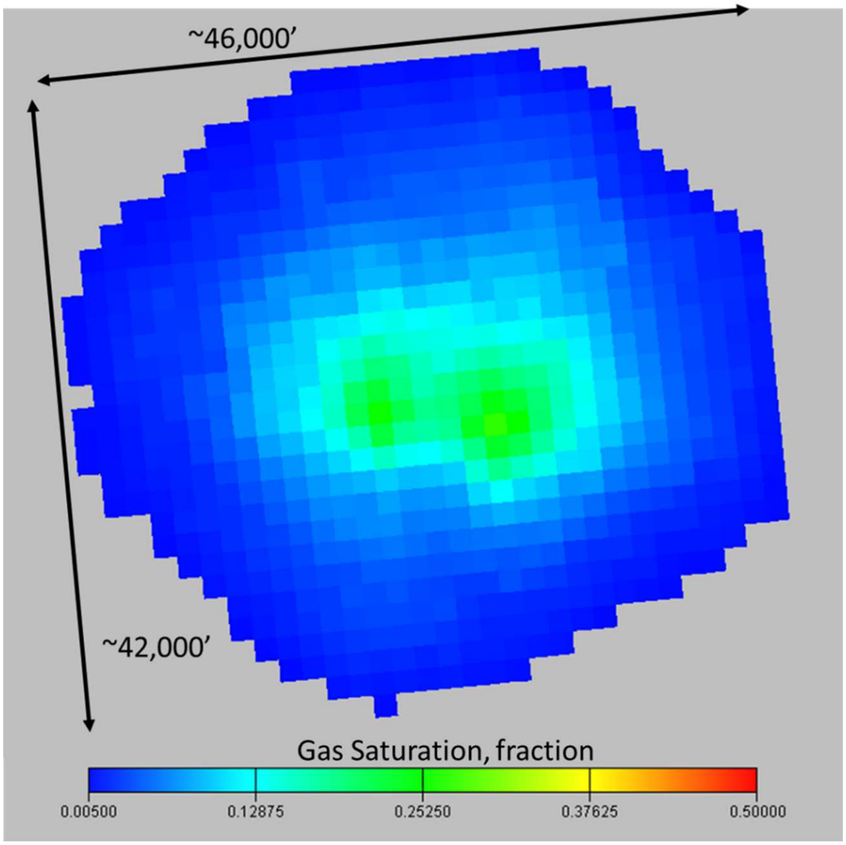

Figure 3.4 – AGI Gas Saturations at Year-end 2986

4.0 Evaluation of Potential Pathways for Leakage to the Surface

This section assesses the potential pathways for leakage of injected CO_2 to the surface. ExxonMobil has identified the potential leakage pathways within the monitoring area as:

1. Leakage from surface equipment (pipeline and wellhead)
2. Leakage through wells
3. Leakage through faults and fractures
4. Leakage through the seal

As will be demonstrated in the following sections, there are no leakage pathways that are likely to result in loss of CO_2 to the atmosphere. Further, given the relatively high concentration of H_2S in the injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by alarms and addressed, thereby minimizing the amount of CO_2 released to the atmosphere.

4.1 Leakage from Surface Equipment

Leakage from surface equipment is not likely due to the design of the AGI facilities. The AGI facilities were designed to minimize leak points such as valves and flanges, and use welded connections where possible instead. The only surface equipment located between the flow meter

and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H_2S in the injection stream at a concentration of 50 - 65% (500,000 - 650,000 ppm), H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons, which alarm at 5 ppm. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2 entrained in the acid gas, at this relative concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm, and immediate action would be taken to stop the leak. Accordingly, in the unlikely event of such a leak, its magnitude would be small.

ExxonMobil reduces the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine inspections. Field personnel monitor the AGI facility continuously through the distributed controls system (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections rounds are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. ExxonMobil also relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSV's), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Additionally, the wells have multiple surface isolation valves for redundant protection if there are any issues with the SCSSV's. Inline inspections of the injection pipelines using a smart pigging tool are conducted on a regular frequency to check the wall thickness of the pipeline to identify potential areas of corrosion.

Should leakage be detected from surface equipment, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

4.2 Leakage through Wells

Leakage of CO_2 through oil, gas, and/or water wells completed and/or abandoned is not likely. There is no commercial production of oil or gas within the immediate area of the SCTF. There is shallower production of gas from the Frontier and Dakota formations nearby in the Cow Hollow Field, at depths of 10,800' – 11,800'. A search of the WOGCC database demonstrated that there are no existing Madison penetrations or production within the MMA other than the AGI wells. The nearest established Madison production is greater than 40 miles to the north-northwest in the ExxonMobil LaBarge Deep Madison Field, which is the well field that supplies SCTF. One well (Whiskey Butte Unit 1 operated by Wexpro Company), which was located approximately six miles from the AGI wells, was drilled to the Madison formation back in 1974. However, the well never produced from the Madison formation and instead was perforated and had casing installed thousands of feet above in the Frontier formation. The well was ultimately plugged and abandoned in February 1992 and does not pose a risk as a leakage pathway. Two additional Madison penetrations are located between the well field and the AGI wells; both penetrations are outside the boundary of the MMA and therefore do not pose a risk as a leakage pathway. Keller Rubow 1-12 was P&A'd in 1996. Fontenelle II Unit 22-35 was drilled to the Madison formation but currently is only perforated and producing from thousands of feet above in the Frontier formation.

As mentioned in Section 2.3.2, early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. The thin-wall wells that failed have been plugged and abandoned in accordance with regulatory standards. Madison wells that were subsequently drilled were cased using thick-walled/chrome tubulars due to the high H_2S and CO_2 content and subsequent corrosion effects, as well as to combat the sediment flowage problems. Therefore, there is no current risk of failure as all wells currently use or have used thick-walled casing of sufficient strength to penetrate and/or produce the Madison formation.

Future drilling also does not pose a risk as a leakage pathway. Future drilling hazards are implied via the geological model presented in Figures 3.2 and 3.4, which shows that there is limited areal extent of the injection plume. Therefore, the geological model can be used to delineate areas that should be avoided during drilling. This model has also history-matched the AGI injection that has occurred to date and suggests that future injection will closely follow the patterns resulting from the geological model simulation. Additionally, should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from the current acid gas injection wells.

ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a weekly basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors are located at the well sites which alarm at 10 ppm H_2S and would be triggered if a leak from the wellbore to the atmosphere occurred. Additionally, SCSSV's and surface isolation valves are installed at the wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

Should leakage result from the injection wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

4.3 Leakage through Faults and Fractures

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells. As a result, the risk of leakage through this pathway is highly improbable. The absence of faulting also tends to suggest that natural fracturing or permeability enhancement in the Madison is also highly improbable.

Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field. The activation of the salty sediments (which exist below the Nugget formation and above the Madison formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments. It is believed that weakness in the casing of thin-wall cased wells contributes to the ability of the salty sediments to flow local to the wellbore, shearing casing, as this a point of weakness in the structural integrity of the wellbore at this depth. Once thick-walled casing was introduced, failures have decreased or have been eliminated.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. It therefore follows that a lack of faulting, as observed on 2D seismic panels around and through the AGI well sites, will yield formations void of natural fracturing, and the necessary faults are not present to generate pervasive natural fractures. The lack of significant natural fracturing in the Madison reservoir at and around the AGI well sites, in conjunction with active inspection of wellbore image logs within the AGI wells themselves, indicates that natural fractures do not exist, that all flow in the Madison must be from pore to pore, and that ability for fluids to flow will depend solely upon the natural intergranular porosity and permeability of the Madison. It should be noted that the permeability of the Madison is low or 'tight' according to industry definitions of 'tight' and therefore has minimal capability to freely flow fluids through only the pore system of the Madison. Accordingly, there is little potential for lateral migration of the injection fluids.

Prior to drilling the AGI wells, ExxonMobil worked with multiple service companies who provided a range of fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison Formations in the area. Based on a frac gradient of 0.85 pounds per square inch (psi)/foot for the Madison, 0.82 psi/foot for the Morgan, 0.80 psi/foot for the Weber/Amsden, and 0.775 psi/foot for the Phosphoria Formation, and a downhole fracture pressure of 12,167 psi, which corresponds to a surface injection pressure of ~5,500 psi, the injected acid gas will not initiate fractures in the confining zones of overlying strata. Facility limits exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is unlikely.

4.4 Leakage through the Formation Seal

Leakage through the seal of the Madison reservoir is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. In fact, the natural seal is the reason the reservoir exists in the first place – the gas has been trapped in the LaBarge structure over a large amount of geologic time. The rock that forms the natural seal is impermeable to He, a gas with a much smaller molecular volume than CO_2. If the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. The Thaynes Formation's sealing effect is also demonstrated by the fact that all gas production shallower than the Thaynes is void of sour gas, while all gas production below it is enriched in sour gases.

Although natural flowage of the salty sediments below the Nugget formation likely occurs, this flowage does not disturb the sediments to the degree necessary to breach the reservoir seal of the

Madison formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison formation to the surface, the natural gases trapped in the formation would have leaked into the atmosphere during the long course of geological time up to this point. The fact that gas remains trapped at pressure in the Madison formation, it must follow that any natural reactivation or flowage of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface.

The acid gas wells are monitored to ensure that the injected gases stay sequestered. Any escaped CO_2 will be associated with H_2S, which has the potential to cause injury to ExxonMobil employees. The CO_2 injected at SCTF cannot escape without immediate detection, as expanded upon in the below sections.

5.0 Detection, Verification, and Quantification of Leakage

5.1 Leakage Detection

As part of ongoing operations, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. These data are monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. Additionally, SCTF maintains in-field gas detectors to detect H_2S in the vicinity. If one of the gas detectors alarmed, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming will trigger automatic equipment isolation/shutdown to mitigate the leak.

Leakage detection for the AGI wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and Distributed Control System (DCS) surveillance. Table 5.1 provides general information on the leakage pathways, monitoring programs to detect leakage, and location of monitoring. Monitoring will occur for the duration of injection. As will be discussed in Section 7.0 below, ExxonMobil will quantify equipment leaks by using a risk-driven approach and continuous surveillance.

Table 5.1 - AGI Monitoring Programs

Leakage Pathway	Detection Monitoring Program	Monitoring Location
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead

Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	N/A – Leakage pathway is highly improbable	N/A

5.2 Leakage Verification

Responses to leaks are covered in the facility's Emergency Contingency Plan. If there is report or indication of a leak from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the system will be relieved to the flare, not vented, due to the dangerous composition of the gas.

5.3 Leakage Quantification

The leakage from surface equipment will be estimated once leakage has been detected and confirmed. Leakage quantification will consist of a methodology selected by ExxonMobil. Leakage estimating methods may potentially consist of modeling or engineering estimates based on operating conditions at the time of the leak such as temperatures, pressures, volumes, hole size, etc.

6.0 Determination of Baselines

ExxonMobil uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. The following describes ExxonMobil's approach to collecting baseline information.

Visual Inspections

Field personnel conduct daily inspections of the AGI facilities and weekly inspections of the AGI well sites. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

H_2S Detection

The CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high of a concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

Continuous Parameter Monitoring

The DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat.

Well Testing

On an annual basis, the AGI subsurface and wellhead valves are leak tested for mechanical integrity testing as required by the WOGCC. This consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections are conducted of the AGI flow lines through the use of a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised.

7.0 Site Specific Modifications to the Mass Balance Equation

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, ExxonMobil proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H_2S concentration of the AGI fluids, monitoring poses a risk to personnel. Additionally, as mentioned above, even a small leak of this high H_2S gas would trigger an alarm. ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. This continuous surveillance using gas detectors identifies leaks better than an annual leak survey would due to the fact that the gas detectors are in operation at all times. Fugitive leakage would be detected and managed as an upset event and calculated for that event based on operating conditions at that time.

Below describes how ExxonMobil will calculate the mass of CO_2 injected, emitted, and sequestered.

7.1 Mass of CO_2 Received

§98.443 states that "you must calculate the mass of CO_2 received using CO_2 received equations… unless you follow the procedures in §98.444(a)(4)". §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." Since the CO_2 received by the AGI process is wholly injected and not mixed with any other supply of CO_2, the annual mass of CO_2 injected would be equal to the annual mass of CO_2 received. No CO_2 is received in containers.

7.2 Mass of CO_2 Injected

Volumetric flow meters are used to measure the injection volumes at each well. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected. Equation RR-6 will be used to aggregate injection data for wells 2-18 and 3-14.

7.3 Mass of CO_2 Produced

The AGI wells are not part of an enhanced oil recovery process, therefore, there is no CO_2 produced and/or recycled.

7.4 Mass of CO_2 Emitted by Surface Leakage and Equipment Leaks

It is not appropriate to conduct a leak survey in AGI due to the components being unsafe-to-monitor. Entry into AGI requires the individual to don a full face respirator supplied to breathing air, which would make completion of a leak survey very difficult. Due to the high H_2S concentration of the AGI fluids, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time. As already mentioned, gas detectors are in operation continuously to survey the area for leaks; even a small leak of this high H_2S gas would trigger an alarm. This methodology is consistent with 40 CFR 98.448(5), which provides the opportunity for an operator to calculate site-specific variables for the mass balance equation.

Therefore, parameters CO_2E and CO_2FI will be measured using the leakage quantification procedures described earlier in this plan. ExxonMobil will estimate the mass of CO_2 emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. There are no CO_2 emissions from venting due to the high H_2S concentration of the injected gas; blowdown emissions are sent to the flares and are reported under Subpart W for the gas plant.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since ExxonMobil is not actively producing oil or natural gas or any other fluids as part of the AGI process, Equation RR-12 will be used to quantify CO_2 sequestered. Parameter CO_2I will be determined used Equation RR-4, as outlined above in Section 7.2. Parameters CO_2E and CO_2FI will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration.

8.0 Estimated Schedule for Implementation of MRV Plan

The SCTF AGI facility and wells have been operational since 2005 and have been following most of the monitoring procedures outlined in this plan since then. ExxonMobil will begin implementing this MRV plan beginning January 1, 2018 and the GHGRP submittal under Subpart RR will occur on or before March 31, 2019. ExxonMobil anticipates the MRV program will be in effect until the end-of-field-life of the LaBarge assets. At the time of cessation of injection, ExxonMobil will prepare a demonstration supporting the long-term containment determination and submit a request to discontinue reporting under this MRV plan consistent with 40 CFR 98.441(b)(2)(ii).

9.0 Quality Assurance Program

9.1 Monitoring QA/QC

In accordance with the applicable requirements of 40 CFR 98.444, ExxonMobil has incorporated the following provisions into its QA/QC programs:

CO_2 *Injected*

- The flow rate of CO_2 injected is measured with a volumetric flow meter for each injection well and is monitored continuously, allowing the flow rate to be compiled quarterly.
- The injected CO_2 stream will be measured upstream of the volumetric flow meter at the three AGI compressors, at which measurement of the CO_2 is representative of the CO_2 stream being injected, with a continuous gas composition analyzer.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO_2 composition of the injected stream.
- The CO_2 analyzers are calibrated according to manufacturer recommendations.

CO_2 *emissions from equipment leaks and vented emissions of* CO_2

- Gas detectors are operated continuously except as necessary for maintenance and calibration
- Gas detectors will be operated and calibrated according to manufacturer recommendations and API standards

Measurement Devices

- Flow meters are operated continuously except as necessary for maintenance and calibration
- Flow meters are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i)
- Flow meters are operated according to an appropriate standard method published by a consensus-based standards organization

- Flow meter calibrations are traceable to National Institute of Standards and Technology (NIST)

General

- The CO_2 concentration is measured using continuous gas analyzers, which is an industry standard practice.
- All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data Procedures

In the event ExxonMobil is unable to collect data needed for the mass balance calculations, 40 CFR 98.445 procedures for estimating missing data will be used as follows:

- If a quarterly quantity of CO_2 injected is missing, it will be estimated using a representative quantify of CO_2 injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures will be followed in accordance with those specified in subpart W of 40 CFR Part 98.

9.3 MRV Plan Revisions

If any of the changes outlined in 40 CFR 98.448(d) occur, ExxonMobil will revise and submit the MRV plan within 180 days to the Administrator for approval.

10.0 Records Retention

ExxonMobil will follow the record retention requirements of 98.3(g). Additionally, it will retain the following records for at least three years:

- Quarterly records of injected CO_2 including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Appendix B: Submissions and Responses to Requests for Additional Information

ExxonMobil Shute Creek Treating Facility Subpart RR Monitoring, Reporting and Verification Plan

February 2018

Table of Contents

Introduction

Exxon Mobil Corporation (ExxonMobil) operates two acid gas injection (AGI) wells in the Madison reservoir located near LaBarge, Wyoming for the primary purpose of acid gas disposal with a subsidiary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. ExxonMobil has developed this monitoring, reporting, and verification (MRV) plan in accordance with 40 CFR §98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for the monitoring, reporting and verification of geologic sequestration in the Madison reservoir during the injection period. This plan meets the requirement in §98.440(c)(1).

This MRV plan contains ten sections:

- Section 1 contains facility information.
- Section 2 contains the project description. This section describes the geology of the LaBarge Field, the history of the LaBarge field, an overview of the injection program and process, and provides the planned injection volumes. This section also demonstrates the suitability for secure geologic storage in the Madison reservoir.
- Section 3 contains the delineation of the monitoring areas.
- Section 4 evaluates the potential leakage pathways and demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.
- Section 5 provides information on the detection, verification, and quantification of leakage. Leakage detection incorporates several monitoring programs including routine visual inspections, H_2S alarms, mechanical integrity testing of the well sites, and continuous surveillance of various parameters. Detection efforts will be focused towards managing potential leaks through the injection wells and surface equipment due to the improbability of leaks through the seal or faults and fractures.
- Section 6 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO_2 leakage.
- Section 7 provides the site specific modifications to the mass balance equation and the methodology for calculating volumes of CO_2 sequestered.
- Section 8 provides the estimated schedule for implementation of the MRV plan.
- Section 9 describes the quality assurance program.
- Section 10 describes the records retention process.

1.0 Facility Information

i) Reporter number: 523107
The AGI wells report under the Shute Creek Treating Facility (SCTF) Greenhouse Gas Reporting Program Identification number, which is: 523107.

ii) Underground Injection Control (UIC) Permit Class: Class II
The Wyoming Oil and Gas Conservation Commission (WOGCC) regulates oil and gas activities in Wyoming. Both AGI wells in LaBarge are classified as UIC Class II wells.

iii) UIC injection well identification numbers:

Well Name	AGI 2-18	AGI 3-14
Well Identification Number	4902321687	4902321674

2.0 Project Description

This section describes the planned injection volumes, environmental setting of the LaBarge Field, injection process, and reservoir modeling.

2.1 Geology of the LaBarge Field

The LaBarge field area is located in the southwestern corner of Wyoming, contained in Lincoln and Sublette counties. The producing field area is within the Green River Basin and the field is located due west of the Wind River Mountains along the Moxa Arch (Figure 2.1).

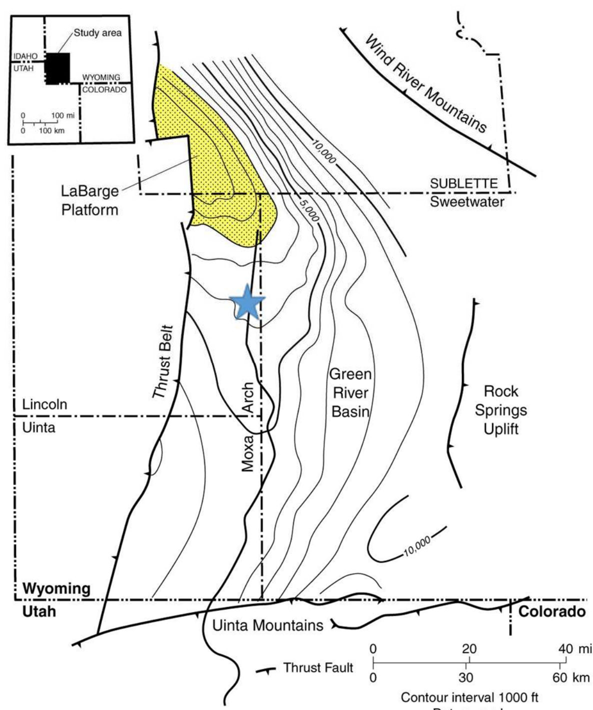

Figure 2.1 Location Map of the LaBarge Field, Wyoming. The injection area is denoted by the blue star.

2.2 Stratigraphy of the Greater LaBarge Field Area

The western region of Wyoming has been endowed in a very rich and prolific series of hydrocarbon reservoirs. Hydrocarbon production has been established or proven from a large number of stratigraphic intervals around Wyoming, ranging from reservoirs from Cenozoic to Paleozoic in age. Figure 2.2 shows a complete stratigraphic column applicable to the Greater Green River Basin in western Wyoming.

For the LaBarge field area, specifically, commercially producible quantities of hydrocarbons have been proven in the following intervals:

- Upper Cretaceous Frontier formation
- Lower Cretaceous Muddy formation
- Permian Phosphoria formation
- Lower Jurassic Nugget formation
- Pennsylvanian Weber formation
- Mississippian Madison formation

2.3 Structural Geology of the LaBarge Field Area

The LaBarge field area lies at the junction of three regional tectonic features: the Wyoming fold and thrust belt to the west, the north-south trending Moxa Arch that provides closure to the LaBarge field, and the Green River Basin to the east. On a regional scale, the Moxa Arch delineates the eastern limit of several regional north-south thrust faults that span the distance between the Wasatch Mountains of Utah to the Wind River Mountains of Wyoming (Figure 2.3).

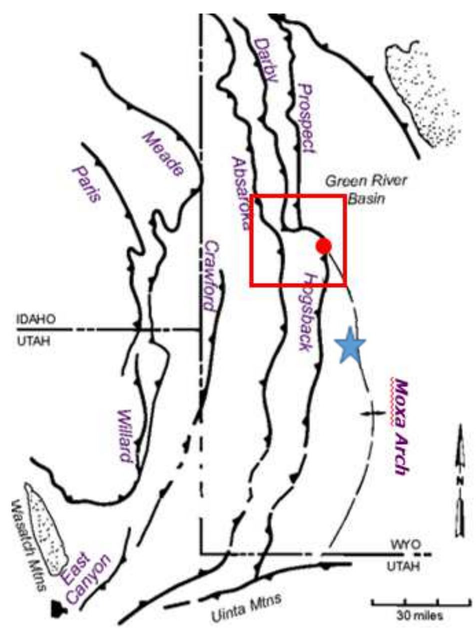

Figure 2.3 Schematic map showing location of Moxa Arch, regional thrust faults. The LaBarge field area is denoted by the red box and the approximate injection area is denoted by the blue star.

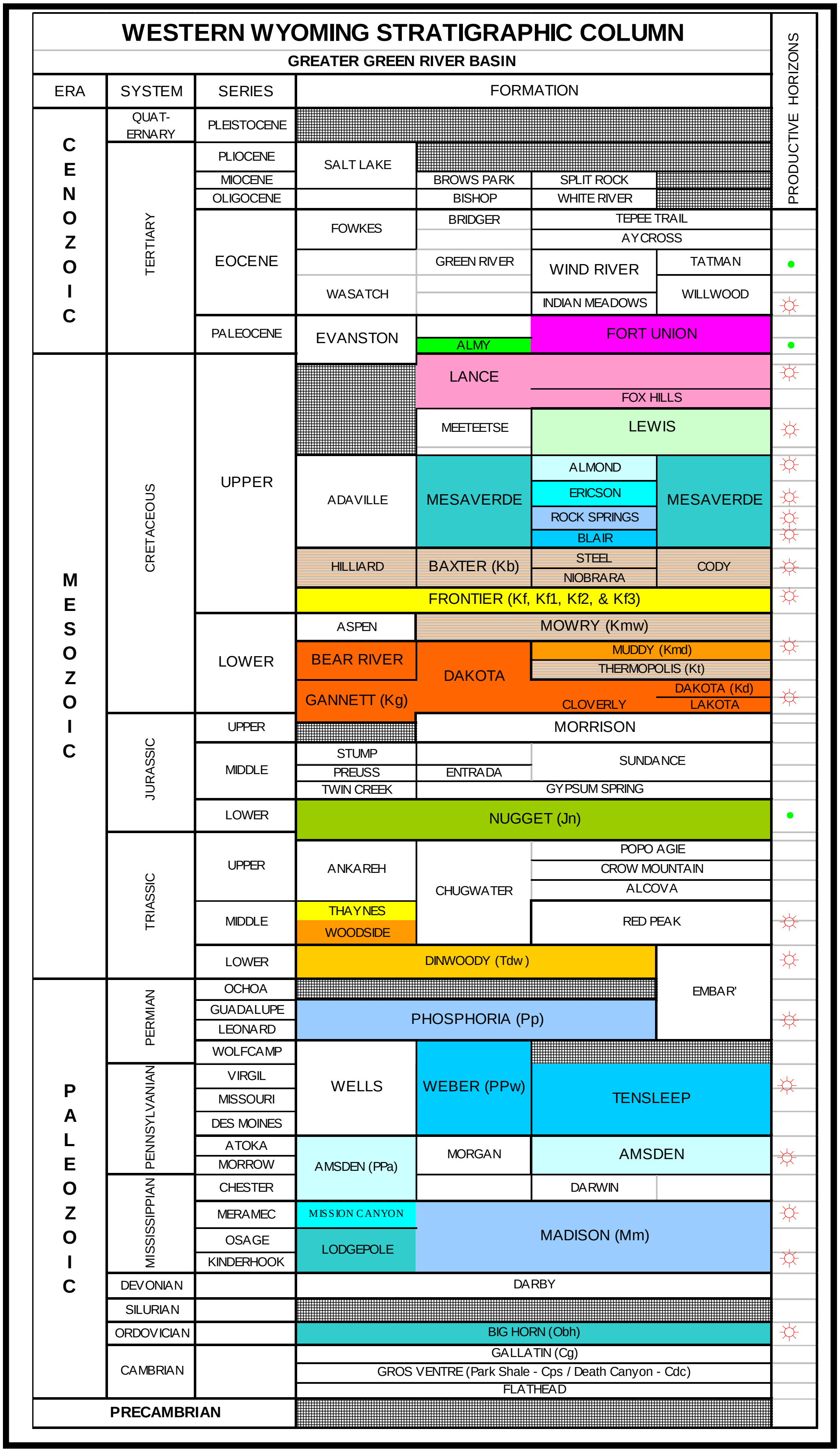

Figure 2.2 Generalized Stratigraphic Column for the Greater Green River Basin, Wyoming

The historical evaluation of structural styles at LaBarge has revealed that three principal styles of structuring have occurred in the area:

- Basement-involved contraction
- Deformation related to flowage of salt-rich Triassic strata
- Basement-detached contraction.

2.3.1 Basement-involved Contraction Events

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinal features being formed along the western edge of the LaBarge field area (Figure 2.3). These regional monoclinal features have been imaged extensively with 2D and 3D seismic data, and are easily recognizable on these data sets (Figure 2.4). At a smaller scale, the monoclinal features set up the LaBarge field structure, creating a hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section.

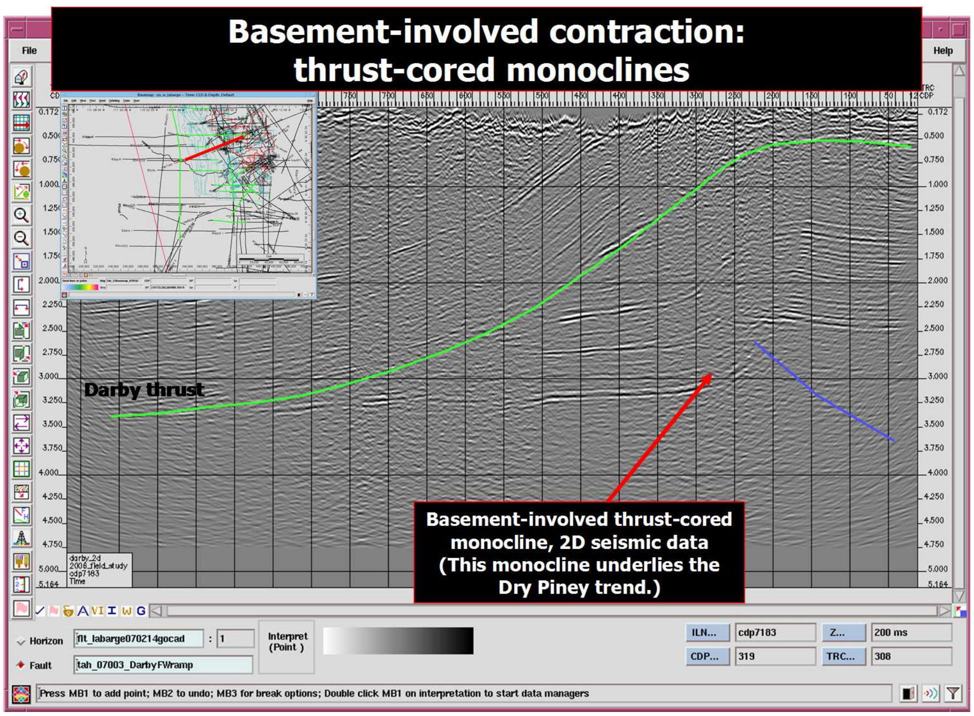

Figure 2.4 Example of thrust-cored monoclinal feature interpreted from 2D seismic data. The thrust-cored feature is believed to be a direct product of basement-involved contractional events.

2.3.2 Deformation of Flowage from Triassic Salt-rich Strata

The second most common style of deformation in the LaBarge field area is the result of flowage from Triassic strata that contain significant amounts of salt. These Triassic sediments have been observed in outcrop to be comprised of interbedded salt and siltstone intervals. At LaBarge, it is not typical to observe thick, continuous sections of pure salt, but rather the interbedded salt and siltstone sections. The 'salty sediments' of this interval have been determined to later evacuate and/or flow, which results in local structural highs being developed around these areas. Figure

2.5 shows two seismic lines showing the Triassic salt-rich sediments and the structuring. The salt-induced local structural features generated via salt evacuation can and do create small, local hydrocarbon traps associated with these sediments. These smaller, localized structures are of a much smaller scale than the main monoclinal hydrocarbon trap of the larger LaBarge field.

The active deformation behavior of these Triassic sediments has been empirically characterized through the drilling history of the LaBarge field. Early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. Subsequent drilling at LaBarge has necessitated using thicker-walled casing strings to combat the sediment flowage problems.

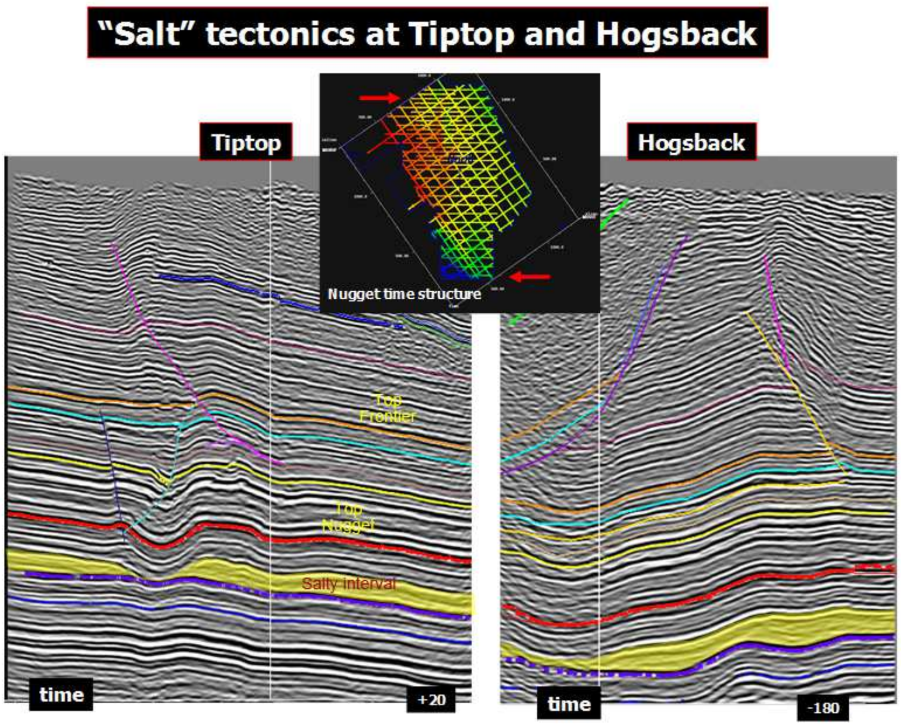

Figure 2.5 Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area (Data courtesy of CGG and WesternGeco)

2.3.3 Basement-detached Contraction

The third main structural style observed at LaBarge field is those resultant from basement-detached contraction. These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. Detachment and contraction along the basement typically creates three types of structural features:

- Regional scale thrust faults
- Localized, smaller scale thrust faults
- Reactivation of Triassic salt-rich sediments resulting in local structural highs (section 2.3.2.).

The basement-detached contraction features typically occur at a regional scale. The subsurface structural features formed through these contractional events are the same size or larger than the greater LaBarge field area. Very large faults are usually associated with these subsurface features, albeit that the reactivation of Triassic salt sediments which can result in additional localized structuring in the area (section 2.3.2).

2.3.4 Faulting and Fracturing of Reservoir Intervals

Reservoir permeability has been observed to increase with the presence of small-scale faults and fractures in almost all of the productive intervals of LaBarge field. Micro-fractures have been observed in core and on formation micro imager (FMI) logs. The fractures seen in the available core are typically filled with calcite, in general.

Empirically, reservoir permeability and increased hydrocarbon productivity have been observed in wells/penetrations that are correlative to areas located on or near structural highs or fault junctions. These empirical observations tend to suggest that these areas have a much higher natural fracture density than others areas or have a larger proportion of natural fractures that are open and not calcite filled. Lack of faulting in an area, as is observed in the area of the existing AGI wells at LaBarge, tends to yield reservoir permeability that is dominated only by matrix or pore-to-pore flow that is generally inhibitive to fluid flow in the subsurface over long distances.

2.3.5 LaBarge Field Structure and Gas Resource of the Madison Formation

Structural closure on the Madison formation at the LaBarge field is quite large, with approximately 4,000’ true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 1,000 square miles making it one of the largest gas fields in North America.

The Madison is estimated to contain approximately 170 trillion cubic feet (TCF) of raw gas and 20 TCF of natural gas (CH_4). At current rates of production, the estimated remaining field life is over 100 years. Spatially, the Madison injection wells have been located at or immediately adjacent to the SCTF, over 40 miles to the southeast from the main LaBarge production areas.

2.4 History of the LaBarge Field Area

The LaBarge field was initially discovered in 1920 with the drilling of a shallow oil producing well. The generalized history of the LaBarge field area is as follows:

- 1907 Oil seeps observed near LaBarge, surface mapping of Tip Top anticline
- 1920 Texas Production Company drills shallow Hilliard sandstone discovery (10 BOPD)
- 1940's General Petroleum (Mobil) explores LaBarge area, surface and seismic mapping

- 1951 Tip Top Field discovered by G.P. (Frontier SS @ 1.8 MCFD, Nugget SS @ 266 BOPD)
- 1952 Belco discovers Frontier gas at Big Piney and LaBarge
- 1954 Belco commits gas to Pacific NW Pipeline, 33 SI gas wells
- 1956 Pacific NW Pipeline completed
- 1956-64 Active drilling of Frontier wells (structural traps)
- 1962 Mobil discovers Madison LS gas at Tip Top, chooses not to develop
- 1970 Exxon evaluates LaBarge area
- 1975-84 2nd major phase of Frontier drilling (stratigraphic traps)
- 1980 Section 29 of Oil Windfall Tax Act for tight gas sands passed (expired 01/01/94)
- 1981 Exxon discovers Madison gas on Lake Ridge Unit (LRU 1-03)
- 1986 First sales of Exxon Madison gas
- 1992 Wyoming Oil & Gas Commission approves 160 acre spacing for Frontier
- 1989-95 Chevron, Enron, PG & E, and Mobil actively drill Frontier targets
- 1999 Exxon and Mobil merge

Historically, Exxon held and operated the Lake Ridge and Fogarty Creek areas of the field, while Mobil operated the Tip Top and Hogsback field areas (Figure 2.6). The heritage operating areas were combined in 1999, with the merger of Exxon and Mobil to form ExxonMobil, into the greater LaBarge operating area. In general, heritage Mobil operations were focused upon shallow sweet gas development drilling while heritage Exxon operations focused upon deeper sour gas production.

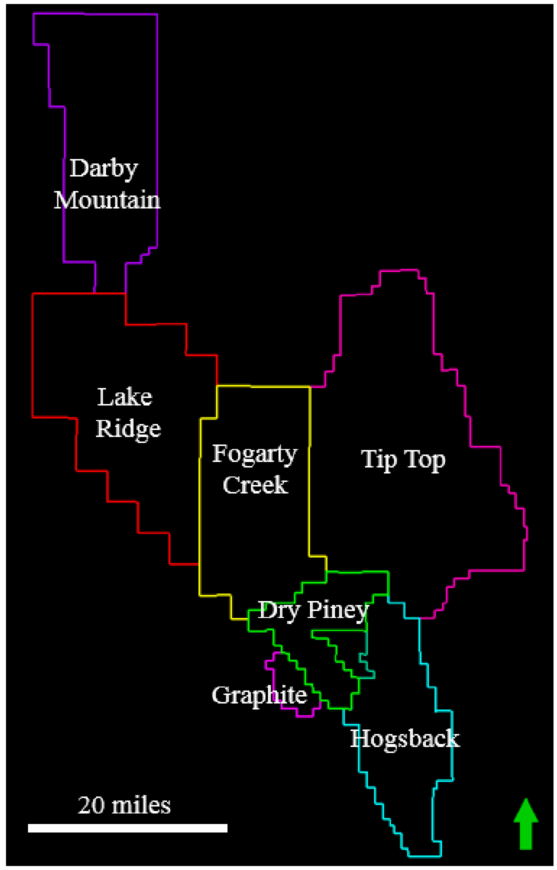

Figure 2.6 Unit map of the greater LaBarge field area

2.5 Initial Discovery of Gas and Early Commercial Production at LaBarge

ExxonMobil's involvement in LaBarge originates in the 1960's with Mobil's discovery of gas in the Madison carbonate formation. The Madison discovery, however, was not commercially developed until much later in the 1980's following Exxon's Madison gas discovery on the Lake Ridge Unit. Subsequently, initial commercial gas production at LaBarge was first established in the Frontier formation, while commercial oil production was established in the Nugget formation.

Gas production from the Madison formation was initiated in 1986 after the start-up of the SCTF, which expanded capacity to handle Madison gas. The total gas in-place for the Madison formation at LaBarge is in excess of 167 TCF gross gas and is a world-class gas reserve that was felt to be economically attractive for production.

2.6 Acid Gas Injection Program History at LaBarge

The Madison formation, once commercial production of gas was established, was found to contain relatively low methane (CH_4) concentration and high carbon dioxide (CO_2) content. The average properties of Madison gas are:

- 21% CH_4
- 66% CO_2
- 7% nitrogen (N_2)
- 5% hydrogen sulfide (H_2S)
- 0.6% helium (He)

Due to the abnormally high CO_2 and H_2S content of Madison gas, the CH_4 was stripped from the raw gas stream leaving a very large need for disposal of the CO_2 and H_2S that remained. For enhanced oil recovery projects (EOR), CO_2 volumes have been historically sold from LaBarge to offset oil operators operating EOR oilfield projects. Originally, the SCTF contained a sulfur recovery unit process to transform the H_2S in the gas stream to elemental sulfur. In 2005, the SRU's were decommissioned to debottleneck the plant and improve plant reliability. This created a need to establish reinjection of the H_2S, and entrained CO_2, to the subsurface.

2.6.1 Geological Overview of AGI Program

Sour gas of up to 66% CO_2 and 5% H_2S is currently produced from the Madison formation at LaBarge. The majority of produced CO_2 is currently being sold by ExxonMobil to other oilfield operators and is being used in EOR projects in the region. The sold volume however, does not equal the total produced CO_2 and H_2S volumes, thereby requiring disposal.

ExxonMobil has pursued the AGI program as a safe and reliable method to re-inject the acid gas into the Madison formation below the field GWC. Gas composition is based on plant injection needs, and will vary between 35 - 50% CO_2 and 50 - 65% H_2S. The gas is injected at a depth of 17,500 feet below the surface and approximately 43 miles away from the main producing areas of LaBarge. Figure 2.7 is a schematic diagram illustrating the AGI program at LaBarge.

2.6.2 Reservoir Quality of Madison Formation in AGI Wells

The existing AGI wells were successfully drilled, logged, and evaluated prior to injection commencement. Figure 2.8 is a schematic of two of the AGI wells (3-14 and 2-18). Petrophysical evaluation of these wells indicate that Madison limestone and dolomite sequences were penetrated, as expected. Total porosity ranges of the limestone sequences were determined to be between 0% and 5%, while the dolomite sequences were found to be up to 20% total porosity. Injection fall-off testing indicated that both wells exhibit greater than 2000 millidarcy-feet (md-ft) of permeability-height within the injection section. Figure 2.9 shows a table summarizing the reservoir properties determined from the 3-14 and 2-18 wells.

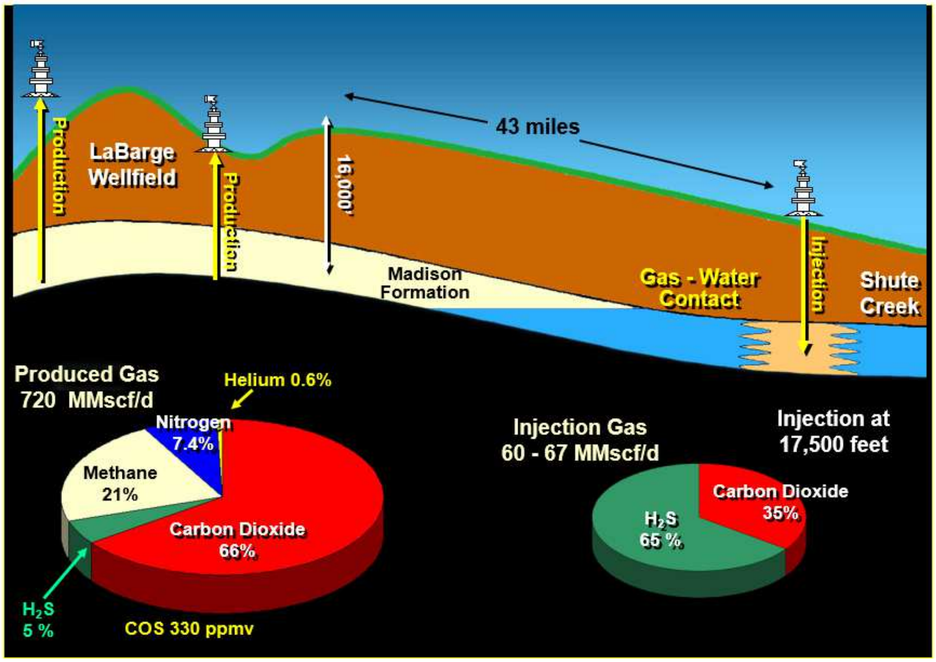

Figure 2.7 Schematic illustration of AGI injection program as currently used at LaBarge

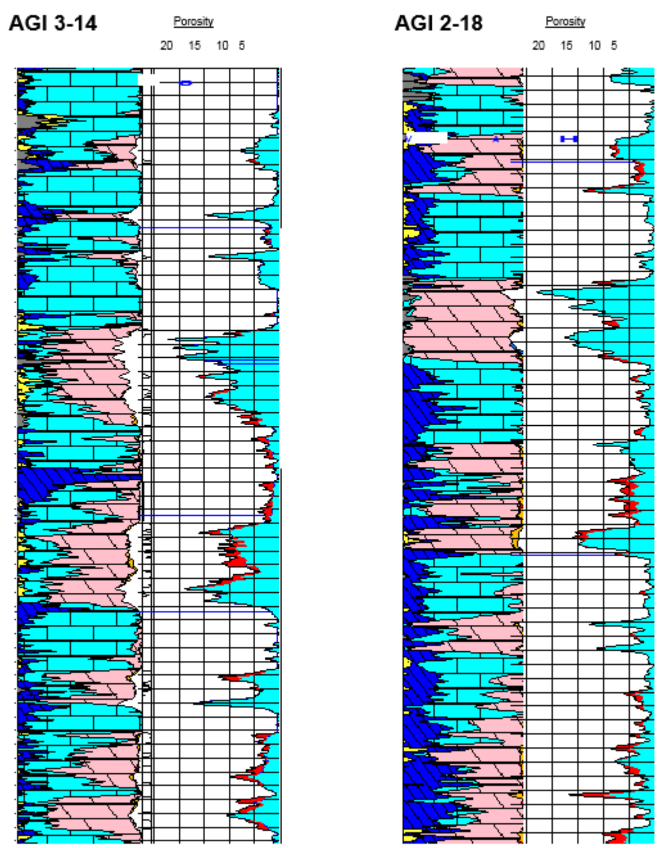

Figure 2.8 Well log sections from the AGI 3-14 and 2-18 injections wells across the Madison formation.

AGI WELLS

	PRE-DRILL	ACTUAL	
		AGI 3-14	AGI 2-18
Net Pay (ft)	210	240	220
Avg ϕ (%)	7%	10%	9%
Avg k (md)	9	9	12
kh (md.ft)	1900	2300*	~2700*
Skin	0	-4.1*	-4.5*

* From injection / falloff test analysis

Figure 2.9 Average reservoir properties of the two AGI wells.

From Figure 2.9, the parameters tabulated include:

- *Net pay:* Madison section that exceeds 5% total porosity.
- *Phi (ϕ):* Total porosity; the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements.
- *K:* Air permeability, which is measured in units of darcy; a measure of the ability of fluids to move from pore to pore in a rock. Note that the measure of darcy assumes linear flow (i.e. pipe shaped).
- *Kh:* Millidarcy-feet, which is a measure of the average permeability calculated at a 0.5 foot sample rate from the well log accumulated over the total net pay section encountered.
- *Skin:* Relative measure of damage or stimulation enhancement to formation permeability in a well completion. Negative skin values indicate enhancement of permeability through the completion whereas positive values indicate hindrance of permeability or damage via the completion.

2.6.3 Seismic Expression of Madison Formation at AGI Well Location

Seismic expression of the Madison formation at the injection location indicates that the injection wells are located on the plunging crest of the Moxa Arch with little to no structuring observable on the seismic data. Faulting is also not indicated by the seismic data. Figure 2.10 shows example lines from the AGI injection area at four times vertical exaggeration.

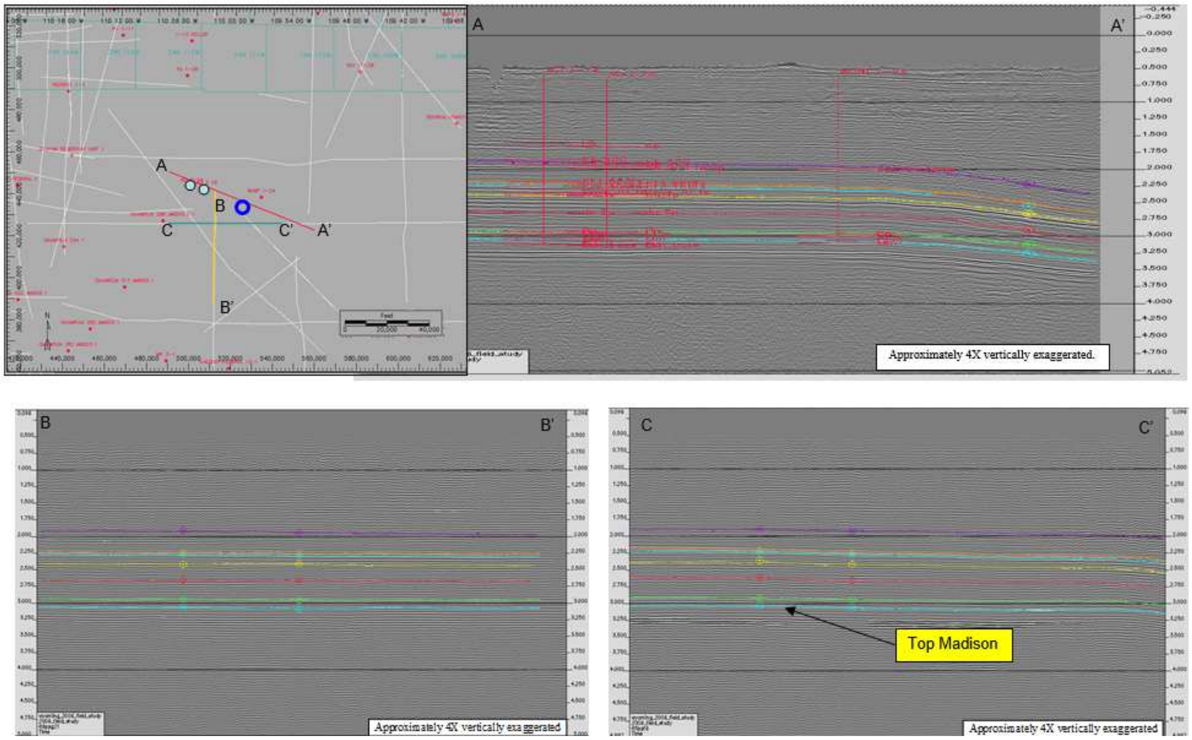

Figure 2.10 Seismic traverses around AGI injection well locations showing no evidence of faulting or structuring around the AGI wells

2.7 Description of the Injection Process

The AGI facility was commissioned for eliminating the Claus Sulfur Recovery Units bottleneck, reducing plant downtime, and reducing operating costs. The purpose of AGI is to take the H_2S and some of the CO_2 removed from the produced raw gas and inject it back into the Madison reservoir. Production of raw gas and injection of acid gas are out of and into the Madison Formation. The Madison reservoir fluid contains very little CH_4 and He at the lower injection locations under SCTF, where the AGI wells are located. Thus, there is no concern of contaminating the production from the LaBarge well field 43 miles away.

The AGI system transports the acid gas stripped in the Selexol process under pressure through a pipeline to two underground wells that are geologically suitable for storage of the acid gas. There are three parallel compressor trains. Two trains are required for full capacity; the third train is a spare. The low pressure feed from the Selexol process enters the first stage suction and is compressed through four stages of compression. The high pressure acid gas from the Selexol process requires only three stages of compression. The fourth stage discharge acid gas must be condensed prior to pumping to prevent damage from vapors. Fourth stage discharge acid gas is cooled in three heat exchangers prior to entering the pump. Dense phase aerial coolers are located downstream of the pumps; they remove heat generated by pumping and increase the density of the fluid. The liquid H_2S/CO_2 is commingled downstream of the dense phase coolers and divided to the two injection wells (3-14 and 2-18). The approximate stream composition being injected is 50 - 65% H_2S and 35 - 50% CO_2.

Each injection well has a dedicated six-inch carbon steel pipeline. The length of pipeline from the AGI battery limit to the injection wells is about:

- 3,200 feet to AGI 3-14
- 12,400 feet to AGI 2-18

The AGI flow lines are buried with seven feet of cover. Heat tracing is provided for the aboveground portions of the lines to prevent the fluid from cooling to the point where free water settles out. Free water and liquid H_2S/CO_2 form acids, which could lead to corrosive conditions. Additionally, the gas is dehydrated before it enters the flow line, reducing the possibility of free water formation, and the water content of the gas is continuously monitored. The liquid H_2S/CO_2 flows via the injection lines to two injection wells. The total depth of each well is about:

- 18,015 feet for AGI 3-14
- 18,017 feet for AGI 2-18.

2.8 Planned Injection Volumes

The below graph is a long-term injection forecast through the life of the injection project. It is based on historic and predicted data. It is important to note that this is just a forecast; actual injection volumes will be collected, calculated, and reported as required by Subpart RR. Additionally, the volumes provided below are the total amount of gas to be injected, not just the CO_2 portion. ExxonMobil forecasts the total volume of CO_2 stored over the modeled injection period to be approximately 37 million metric tons.

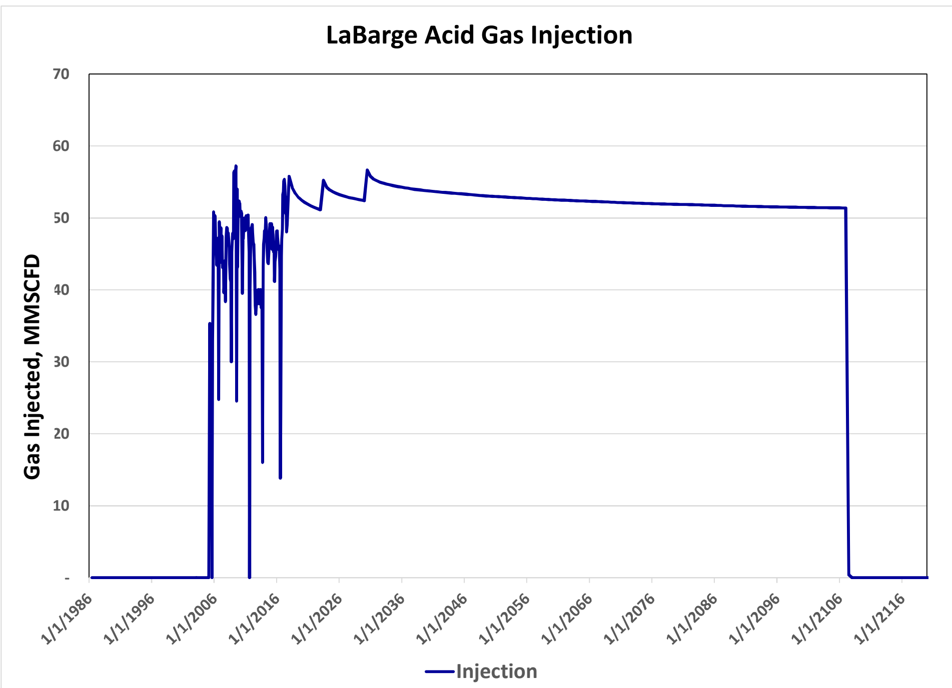

Figure 2.11 – Planned Injection Volumes

3.0 Delineation of Monitoring Area

3.1 Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the acid gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 0.5%. A gas saturation of 0.5% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison formation.

After injecting 0.2 TCF by year-end 2017, the estimated acid gas plume size is approximately 15,000 feet in diameter (2.84 miles) (see Figure 3.1). With continuing injection of an additional 1.7 TCF through year-end 2106, at which injection is expected to cease, the plume size is expected to grow to approximately 36,000 feet in diameter (6.82 miles) (see Figure 3.2). Figure 3.3 shows how the predicted plume average diameter is expected to change over time. The model was run through July 2986 to assess the potential for expansion of the plume after acid gas injection ceases. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. Expansion of the plume to a diameter of approximately 42,000 feet (7.95 miles) occurs by the year 2500 as the gas plume settles due to gravity segregation and dispersion. The plume is expected to continue settling, with a modeled plume size of approximately 44,000 feet (8.33 miles) by July 2986, 1000 years after production of the LaBarge field started and over 800 years after injection was shut-in. At this point, the rate of movement of the free-phase gas plume has decreased to less than four feet per year, demonstrating plume stability. Therefore, the MMA will be defined by Figure 3.4, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume in July 2986, which is an 8.3-mile diameter) plus the buffer zone of one-half mile.

3.2 Active Monitoring Area (AMA)

ExxonMobil proposes to define the AMA as the same boundary as the MMA. The following factors were considered in defining this boundary:

- Lack of faulting in the MMA yields no vertical pathways for fluids to move vertically out of the Madison to shallower intervals.
- Lack of faulting in the injection area does not create enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be darcy flow from pore to pore.
- Distance from the LaBarge production field area is large (30 miles) and formation permeability is generally low which naturally inhibits flow aerially from injection site.

- The LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons for large geologic periods of time. There is no reason to believe that any injection fluids that may migrate outwards from the injection site to the larger LaBarge structure would not also be effectively trapped at the LaBarge structure over geological time.

The purpose of the AMA is to allow for a practical and cost-effective monitoring program throughout the life of the project. Because there are no probable leakage pathways in the maximum monitoring area, besides surface equipment which is extensively monitored, ExxonMobil believes it is appropriate to define the AMA as the same boundary as the MMA. Additionally, due to the high H_2S content of the injected gas stream, monitoring of leaks is essential to operations and personnel safety, so a full-scale monitoring program has already been implemented at the AGI sites, as will be discussed below.

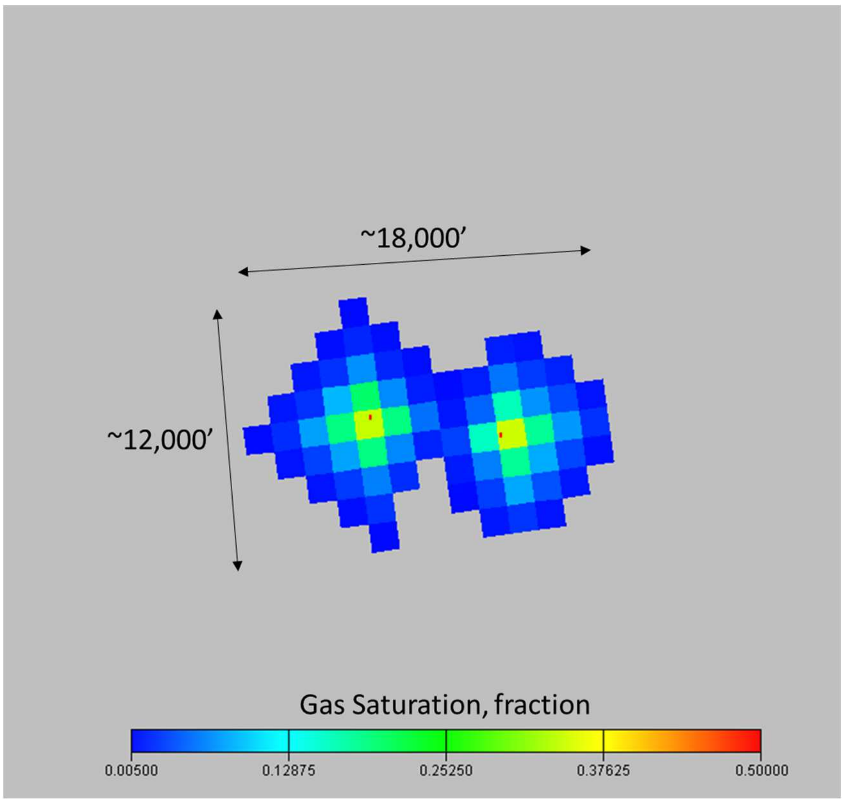

Figure 3.1 – AGI Gas Saturations at Year-end 2017

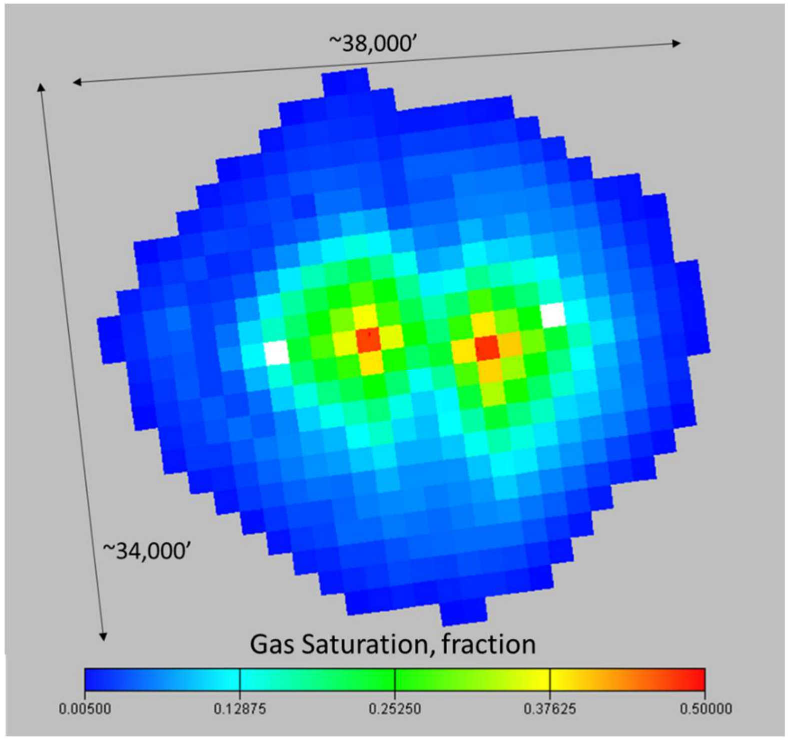

Figure 3.2 – AGI Gas Saturations at Year-end 2106

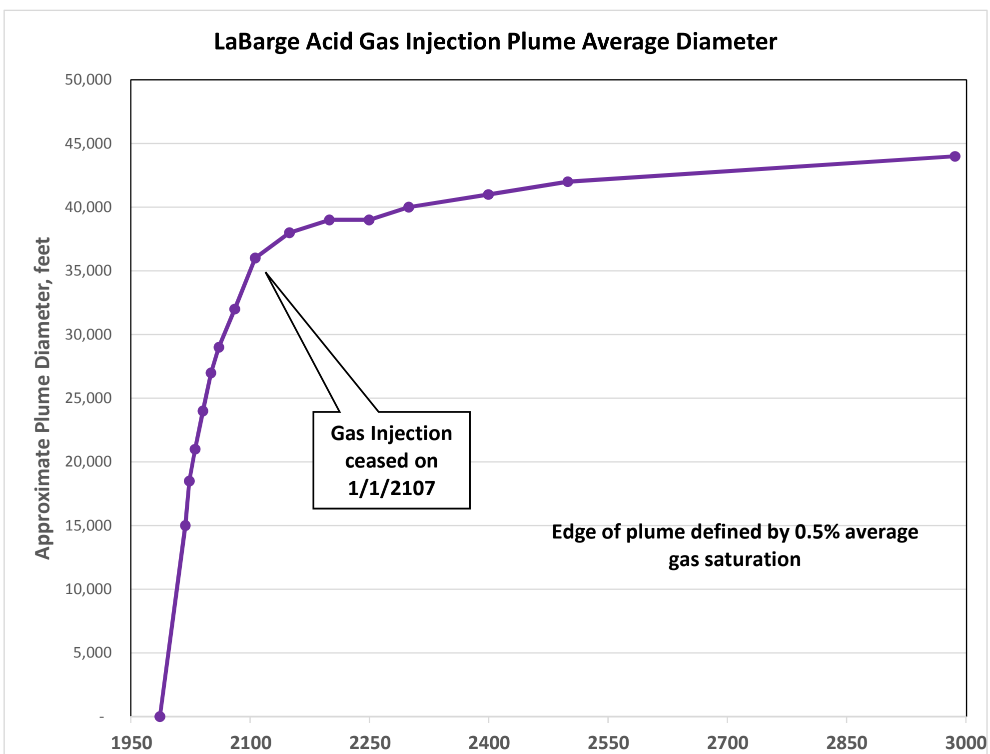

Figure 3.3 – Predicted LaBarge AGI Plume Diameter

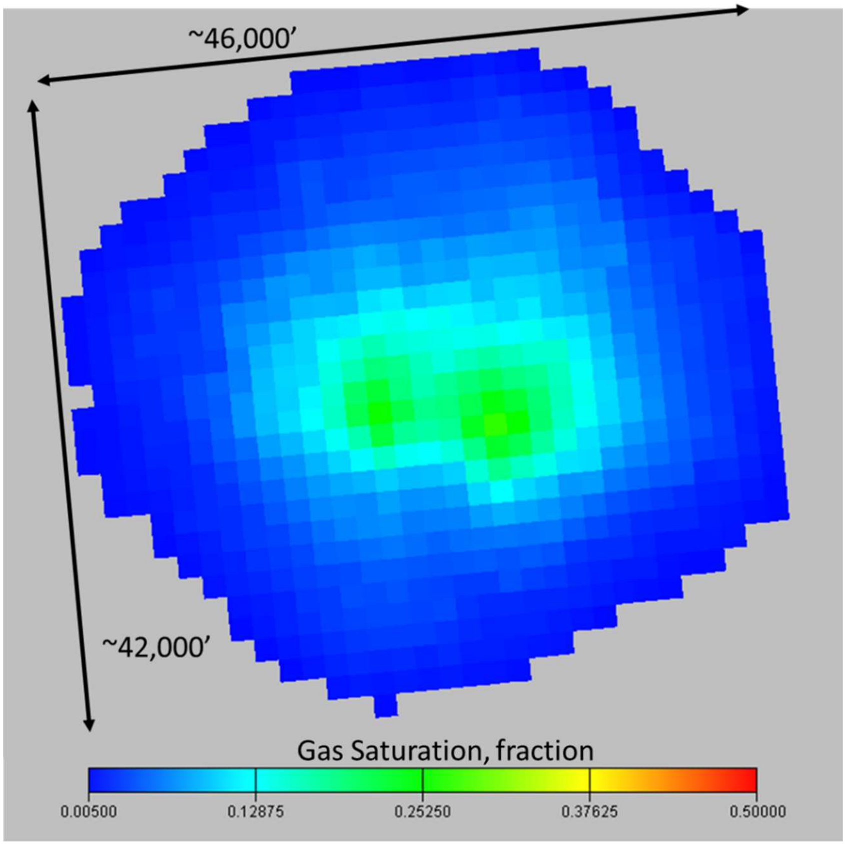

Figure 3.4 – AGI Gas Saturations at Year-end 2986

4.0 Evaluation of Potential Pathways for Leakage to the Surface

This section assesses the potential pathways for leakage of injected CO_2 to the surface. ExxonMobil has identified the potential leakage pathways within the monitoring area as:

1. Leakage from surface equipment (pipeline and wellhead)
2. Leakage through wells
3. Leakage through faults and fractures
4. Leakage through the seal

As will be demonstrated in the following sections, there are no leakage pathways that are likely to result in loss of CO_2 to the atmosphere. Further, given the relatively high concentration of H_2S in the injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by alarms and addressed, thereby minimizing the amount of CO_2 released to the atmosphere.

4.1 Leakage from Surface Equipment

Leakage from surface equipment is not likely due to the design of the AGI facilities. The AGI facilities were designed to minimize leak points such as valves and flanges, and use welded connections where possible instead. The only surface equipment located between the flow meter

and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H_2S in the injection stream at a concentration of 50 - 65% (500,000 - 650,000 ppm), H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons, which alarm at 5 ppm. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2 entrained in the acid gas, at this relative concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm, and immediate action would be taken to stop the leak. Accordingly, in the unlikely event of such a leak, its magnitude would be small.

ExxonMobil reduces the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine inspections. Field personnel monitor the AGI facility continuously through the distributed controls system (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections rounds are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. ExxonMobil also relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSV's), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Additionally, the wells have multiple surface isolation valves for redundant protection if there are any issues with the SCSSV's. Inline inspections of the injection pipelines using a smart pigging tool are conducted on a regular frequency to check the wall thickness of the pipeline to identify potential areas of corrosion.

Should leakage be detected from surface equipment, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

4.2 Leakage through Wells

Leakage of CO_2 through oil, gas, and/or water wells completed and/or abandoned is not likely. There is no commercial production of oil or gas within the immediate area of the SCTF. There is shallower production of gas from the Frontier and Dakota formations nearby in the Cow Hollow Field, at depths of 10,800' – 11,800'. A search of the WOGCC database demonstrated that there are no existing Madison penetrations or production within the MMA other than the AGI wells. The nearest established Madison production is greater than 40 miles to the north-northwest in the ExxonMobil LaBarge Deep Madison Field, which is the well field that supplies SCTF. One well (Whiskey Butte Unit 1 operated by Wexpro Company), which was located approximately six miles from the AGI wells, was drilled to the Madison formation back in 1974. However, the well never produced from the Madison formation and instead was perforated and had casing installed thousands of feet above in the Frontier formation. The well was ultimately plugged and abandoned in February 1992 and does not pose a risk as a leakage pathway. Two additional Madison penetrations are located between the well field and the AGI wells; both penetrations are outside the boundary of the MMA and therefore do not pose a risk as a leakage pathway. Keller Rubow 1-12 was P&A'd in 1996. Fontenelle II Unit 22-35 was drilled to the Madison formation but currently is only perforated and producing from thousands of feet above in the Frontier formation.

As mentioned in Section 2.3.2, early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. The thin-wall wells that failed have been plugged and abandoned in accordance with regulatory standards. Madison wells that were subsequently drilled were cased using thick-walled/chrome tubulars due to the high H_2S and CO_2 content and subsequent corrosion effects, as well as to combat the sediment flowage problems. Therefore, there is no current risk of failure as all wells currently use or have used thick-walled casing of sufficient strength to penetrate and/or produce the Madison formation.

Future drilling also does not pose a risk as a leakage pathway. Future drilling hazards are implied via the geological model presented in Figures 3.2 and 3.4, which shows that there is limited areal extent of the injection plume. Therefore, the geological model can be used to delineate areas that should be avoided during drilling. This model has also history-matched the AGI injection that has occurred to date and suggests that future injection will closely follow the patterns resulting from the geological model simulation. Additionally, should future drilling occur, it would occur near the existing production area, which is greater than 40 miles away from the current acid gas injection wells.

ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a weekly basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors are located at the well sites which alarm at 10 ppm H_2S and would be triggered if a leak from the wellbore to the atmosphere occurred. Additionally, SCSSV's and surface isolation valves are installed at the wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

Should leakage result from the injection wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

4.3 Leakage through Faults and Fractures

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells. As a result, the risk of leakage through this pathway is highly improbable. The absence of faulting also tends to suggest that natural fracturing or permeability enhancement in the Madison is also highly improbable.

Current-day regional scale thrust faulting has not been observed in the LaBarge area since the field has been under development. There is no concern of reactivation of these thrust faults and it is hypothesized that regional structuring similar in size to the Laramide Orogeny (formation of the Rocky Mountains) would be required to generate new thrust faults of significant size to produce subsurface structures of the scale and magnitude of the LaBarge field. The activation of the salty sediments (which exist below the Nugget formation and above the Madison formation at LaBarge) is a phenomenon that was only observed to damage thin-wall cased wells, with thick-wall cased wells having sufficient strength to prevent flowage of these salt sediments. It is believed that weakness in the casing of thin-wall cased wells contributes to the ability of the salty sediments to flow local to the wellbore, shearing casing, as this a point of weakness in the structural integrity of the wellbore at this depth. Once thick-walled casing was introduced, failures have decreased or have been eliminated.

It has been documented that natural fracturing of reservoirs in the subsurface of LaBarge and surrounding areas are directly correlative to distance to thrust faults in the area. This correlation has been documented in subsurface wellbore image logs and also by surface geological mapping around the thrust faults in the LaBarge area. It therefore follows that a lack of faulting, as observed on 2D seismic panels around and through the AGI well sites, will yield formations void of natural fracturing, and the necessary faults are not present to generate pervasive natural fractures. The lack of significant natural fracturing in the Madison reservoir at and around the AGI well sites, in conjunction with active inspection of wellbore image logs within the AGI wells themselves, indicates that natural fractures do not exist, that all flow in the Madison must be from pore to pore, and that ability for fluids to flow will depend solely upon the natural intergranular porosity and permeability of the Madison. It should be noted that the permeability of the Madison is low or ‘tight’ according to industry definitions of ‘tight’ and therefore has minimal capability to freely flow fluids through only the pore system of the Madison. Accordingly, there is little potential for lateral migration of the injection fluids.

Prior to drilling the AGI wells, ExxonMobil worked with multiple service companies who provided a range of fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison Formations in the area. Based on a frac gradient of 0.85 pounds per square inch (psi)/foot for the Madison, 0.82 psi/foot for the Morgan, 0.80 psi/foot for the Weber/Amsden, and 0.775 psi/foot for the Phosphoria Formation, and a downhole fracture pressure of 12,167 psi, which corresponds to a surface injection pressure of ~5,500 psi, the injected acid gas will not initiate fractures in the confining zones of overlying strata. Facility limits exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is unlikely.

4.4 Leakage through the Formation Seal

Leakage through the seal of the Madison reservoir is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. In fact, the natural seal is the reason the reservoir exists in the first place – the gas has been trapped in the LaBarge structure over a large amount of geologic time. The rock that forms the natural seal is impermeable to He, a gas with a much smaller molecular volume than CO_2. If the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. The Thaynes Formation’s sealing effect is also demonstrated by the fact that all gas production shallower than the Thaynes is void of sour gas, while all gas production below it is enriched in sour gases.

Although natural flowage of the salty sediments below the Nugget formation likely occurs, this flowage does not disturb the sediments to the degree necessary to breach the reservoir seal of the

Madison formation. If this salty sediment were to flow on a scale large enough to create a leakage pathway from the Madison formation to the surface, the natural gases trapped in the formation would have leaked into the atmosphere during the long course of geological time up to this point. The fact that gas remains trapped at pressure in the Madison formation, it must follow that any natural reactivation or flowage of salt-rich sediments that has occurred over the geological history of the LaBarge field area has not created any pathways for gas leakage to the surface.

The acid gas wells are monitored to ensure that the injected gases stay sequestered. Any escaped CO_2 will be associated with H_2S, which has the potential to cause injury to ExxonMobil employees. The CO_2 injected at SCTF cannot escape without immediate detection, as expanded upon in the below sections.

5.0 Detection, Verification, and Quantification of Leakage

5.1 Leakage Detection

As part of ongoing operations, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. These data are monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. Additionally, SCTF maintains in-field gas detectors to detect H_2S in the vicinity. If one of the gas detectors alarmed, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming will trigger automatic equipment isolation/shutdown to mitigate the leak.

Leakage detection for the AGI wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and Distributed Control System (DCS) surveillance. Table 5.1 provides general information on the leakage pathways, monitoring programs to detect leakage, and location of monitoring. Monitoring will occur for the duration of injection. As will be discussed in Section 7.0 below, ExxonMobil will quantify equipment leaks by using a risk-driven approach and continuous surveillance.

Table 5.1 - AGI Monitoring Programs

Leakage Pathway	Detection Monitoring Program	Monitoring Location
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead

Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation
Faults and Fractures, Formation Seal, Lateral Migration	N/A – Leakage pathway is highly improbable	N/A

5.2 Leakage Verification

Responses to leaks are covered in the facility's Emergency Contingency Plan. If there is report or indication of a leak from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the system will be relieved to the flare, not vented, due to the dangerous composition of the gas.

5.3 Leakage Quantification

The leakage from surface equipment will be estimated once leakage has been detected and confirmed. Leakage quantification will consist of a methodology selected by ExxonMobil. Leakage estimating methods may potentially consist of modeling or engineering estimates based on operating conditions at the time of the leak such as temperatures, pressures, volumes, hole size, etc.

6.0 Determination of Baselines

ExxonMobil uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. The following describes ExxonMobil's approach to collecting baseline information.

Visual Inspections

Field personnel conduct daily inspections of the AGI facilities and weekly inspections of the AGI well sites. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

<u>H_2S Detection</u>

The CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high of a concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

<u>Continuous Parameter Monitoring</u>

The DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat.

<u>Well Testing</u>

On an annual basis, the AGI subsurface and wellhead valves are leak tested for mechanical integrity testing as required by the WOGCC. This consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections are conducted of the AGI flow lines through the use of a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised.

7.0 Site Specific Modifications to the Mass Balance Equation

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, ExxonMobil proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H_2S concentration of the AGI fluids, monitoring poses a risk to personnel. Additionally, as mentioned above, even a small leak of this high H_2S gas would trigger an alarm. ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. This continuous surveillance using gas detectors identifies leaks better than an annual leak survey would due to the fact that the gas detectors are in operation at all times. Fugitive leakage would be detected and managed as an upset event and calculated for that event based on operating conditions at that time.

Below describes how ExxonMobil will calculate the mass of CO_2 injected, emitted, and sequestered.

7.1 Mass of CO_2 Received

§98.443 states that "you must calculate the mass of CO_2 received using CO_2 received equations… unless you follow the procedures in §98.444(a)(4)". §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." Since the CO_2 received by the AGI process is wholly injected and not mixed with any other supply of CO_2, the annual mass of CO_2 injected would be equal to the annual mass of CO_2 received. No CO_2 is received in containers.

7.2 Mass of CO_2 Injected

Volumetric flow meters are used to measure the injection volumes at each well. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected. Equation RR-6 will be used to aggregate injection data for wells 2-18 and 3-14.

7.3 Mass of CO_2 Produced

The AGI wells are not part of an enhanced oil recovery process, therefore, there is no CO_2 produced and/or recycled.

7.4 Mass of CO_2 Emitted by Surface Leakage and Equipment Leaks

It is not appropriate to conduct a leak survey in AGI due to the components being unsafe-to-monitor. Entry into AGI requires the individual to don a full face respirator supplied to breathing air, which would make completion of a leak survey very difficult. Due to the high H_2S concentration of the AGI fluids, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time. As already mentioned, gas detectors are in operation continuously to survey the area for leaks; even a small leak of this high H_2S gas would trigger an alarm. This methodology is consistent with 40 CFR 98.448(5), which provides the opportunity for an operator to calculate site-specific variables for the mass balance equation.

Therefore, parameters CO_2E and CO_2FI will be measured using the leakage quantification procedures described earlier in this plan. ExxonMobil will estimate the mass of CO_2 emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. There are no CO_2 emissions from venting due to the high H_2S concentration of the injected gas; blowdown emissions are sent to the flares and are reported under Subpart W for the gas plant.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since ExxonMobil is not actively producing oil or natural gas or any other fluids as part of the AGI process, Equation RR-12 will be used to quantify CO_2 sequestered. Parameter CO_2I will be determined used Equation RR-4, as outlined above in Section 7.2. Parameters CO_2E and CO_2FI will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration.

8.0 Estimated Schedule for Implementation of MRV Plan

The SCTF AGI facility and wells have been operational since 2005 and have been following most of the monitoring procedures outlined in this plan since then. ExxonMobil will begin implementing this MRV plan beginning January 1, 2018 and the GHGRP submittal under Subpart RR will occur on or before March 31, 2019. ExxonMobil anticipates the MRV program will be in effect until the end-of-field-life of the LaBarge assets. At the time of cessation of injection, ExxonMobil will prepare a demonstration supporting the long-term containment determination and submit a request to discontinue reporting under this MRV plan consistent with 40 CFR 98.441(b)(2)(ii).

9.0 Quality Assurance Program

9.1 Monitoring QA/QC

In accordance with the applicable requirements of 40 CFR 98.444, ExxonMobil has incorporated the following provisions into its QA/QC programs:

<u>CO_2 *Injected*</u>

- The flow rate of CO_2 injected is measured with a volumetric flow meter for each injection well and is monitored continuously, allowing the flow rate to be compiled quarterly.
- The injected CO_2 stream will be measured upstream of the volumetric flow meter at the three AGI compressors, at which measurement of the CO_2 is representative of the CO_2 stream being injected, with a continuous gas composition analyzer.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO_2 composition of the injected stream.
- The CO_2 analyzers are calibrated according to manufacturer recommendations.

<u>CO_2 *emissions from equipment leaks and vented emissions of* CO_2</u>

- Gas detectors are operated continuously except as necessary for maintenance and calibration
- Gas detectors will be operated and calibrated according to manufacturer recommendations and API standards

<u>*Measurement Devices*</u>

- Flow meters are operated continuously except as necessary for maintenance and calibration
- Flow meters are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i)
- Flow meters are operated according to an appropriate standard method published by a consensus-based standards organization

- Flow meter calibrations are traceable to National Institute of Standards and Technology (NIST)

General

- The CO_2 concentration is measured using continuous gas analyzers, which is an industry standard practice.
- All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data Procedures

In the event ExxonMobil is unable to collect data needed for the mass balance calculations, 40 CFR 98.445 procedures for estimating missing data will be used as follows:

- If a quarterly quantity of CO_2 injected is missing, it will be estimated using a representative quantify of CO_2 injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures will be followed in accordance with those specified in subpart W of 40 CFR Part 98.

9.3 MRV Plan Revisions

If any of the changes outlined in 40 CFR 98.448(d) occur, ExxonMobil will revise and submit the MRV plan within 180 days to the Administrator for approval.

10.0 Records Retention

ExxonMobil will follow the record retention requirements of 98.3(g). Additionally, it will retain the following records for at least three years:

- Quarterly records of injected CO_2 including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Request for Additional Information: ExxonMobil Shute Creek Subpart RR MRV Plan
March 27, 2018

Instructions: Please enter responses into this table. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. Supplemental information may also be provided in a resubmitted MRV plan.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	1	3	MRV Plan: Figures 2.1 and/or 2.3. It would be helpful to show the location of the SCTF facility. It is not located on the map in Figure 2.1 or Figure 2.3.	Updated on both figures.
2.	2.3.2	7	MRV Plan mentions wells that were drilled at LaBarge with thin walled casing were observed to fail due to casing shearing across the Triassic interval. However, this risk was not mentioned in Section 4.2 as a potential leakage pathway. Please clarify why such a concern is not a risk, if true. Alternatively, please describe how such risks may be monitored and, if necessary, mitigated.	Included additional language in Section 4.2 addressing this.
3.	2.3.5	8	MRV Plan: Spatially, the Madison injection wells have been located at or immediately adjacent to the SCTF, approximately 30 miles to the southeast from the main LaBarge production areas. The SCTF and related injection wells are stated to be approximately 30 miles southeast from the main LaBarge production areas, however Figure 2.7 shows the distance to be 43 miles. Please correct or explain.	Updated to read over 40 miles to be consistent with Figure 2.7.
4.	2.6.1 & 2.7	11, 12, 14	The H_2S concentrations are not consistent for the injected stream (50-60% H_2S on page 11, 50-65% H_2S on page 14). Also, update the pie chart in figure 2.7 if necessary (Injection Gas pie chart lists H_2S at 65%).	Updated page 11 to correct H2S range.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	2.6.2	11	MRV Plan: The gas is injected at a depth of 17,500 feet below the surface and approximately 43 miles away from the main producing areas of LaBarge. This is inconsistent with Section 2.3.5, which states the distance is 30 miles away. Please correct or explain.	Injection area is over 40 miles away from production area.
6.	2.7	14	MRV Plan: Thus, there is no concern of contaminating the production from the LaBarge well field 43 miles away. This is inconsistent with Section 2.3.5, which states the distance is 30 miles away. Please correct or explain.	Injection area is over 40 miles away from production area.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.	4.0	19-21	Per 40 CFR 98.448(a)(2), the MRV plan should identify potential surface leakage pathways. A few potential surface leakage pathways are alluded to in Section 2.0, but are not explicitly discussed in Section 4.0. These are: • Seismicity (natural and induced): The discussion of active deformation behavior due to "salty sediments" (pages 6-7); along with that on page 8; "The subsurface structural features formed through these contractional events are the same size or larger than the greater LaBarge field area. Very large faults are usually associated with these subsurface features, albeit that the reactivation of Triassic salt sediments which can result in additional localized structuring in the area (section 2.3.2)." imply minimal concerns about seismicity. This could be explained more explicitly in Section 4.0. • Lateral migration: On page 8, it says: "Lack of faulting in an area, as is observed in the area of the existing AGI wells at LaBarge, tends to yield reservoir permeability that is dominated only by matrix or pore-to-pore flow that is generally inhibitive to fluid flow in the subsurface over long distances." This suggests little potential for lateral migration that could be discussed more fully in Section 4.0. • Future drilling: As discussed in Item 2 above, reference is made to past drilling in the area, but there is not discussion of the potential risks associated with future drilling. While the narrative suggests little concern for issues associated with future drilling, this could be discussed more fully in Section 4.0. If applicable, any additional potential surface leakage pathways should also be added to Table 5.1.	Included additional language in Section 4.3 addressing this. Included additional language in Section 4.3 and Section 4.4 addressing this. Included additional language in Section 4.2 addressing this.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
8.	8.0	25	MRV Plan: ExxonMobil will begin reporting under Subpart RR beginning January 1, 2018 and the GHGRP submittal will occur on or before March 31 of the following year. Suggest editing for clarity that ExxonMobil will begin implementing this MRV Plan beginning January 1, 2018 with the first annual report submittal occurring on or before March 31, 2019.	Corrected Section 8.0 per EPA's suggestion.

ExxonMobil Shute Creek Treating Facility Subpart RR Monitoring, Reporting and Verification Plan

February 2018

Table of Contents

Introduction

Exxon Mobil Corporation (ExxonMobil) operates two acid gas injection (AGI) wells in the Madison reservoir located near LaBarge, Wyoming for the primary purpose of acid gas disposal with a subsidiary purpose of geologic sequestration of carbon dioxide (CO_2) in a subsurface geologic formation. ExxonMobil has been operating the AGI wells since 2005 and intends to continue injection until the end-of-field-life of the LaBarge assets. ExxonMobil has developed this monitoring, reporting, and verification (MRV) plan in accordance with 40 CFR §98.440-449 (Subpart RR – Geologic Sequestration of Carbon Dioxide) to provide for the monitoring, reporting and verification of geologic sequestration in the Madison reservoir during the injection period. This plan meets the requirement in §98.440(c)(1).

This MRV plan contains ten sections:

- Section 1 contains facility information.

- Section 2 contains the project description. This section describes the geology of the LaBarge Field, the history of the LaBarge field, an overview of the injection program and process, and provides the planned injection volumes. This section also demonstrates the suitability for secure geologic storage in the Madison reservoir.

- Section 3 contains the delineation of the monitoring areas.

- Section 4 evaluates the potential leakage pathways and demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

- Section 5 provides information on the detection, verification, and quantification of leakage. Leakage detection incorporates several monitoring programs including routine visual inspections, H_2S alarms, mechanical integrity testing of the well sites, and continuous surveillance of various parameters. Detection efforts will be focused towards managing potential leaks through the injection wells and surface equipment due to the improbability of leaks through the seal or faults and fractures.

- Section 6 describes the determination of expected baselines to identify excursions from expected performance that could indicate CO_2 leakage.

- Section 7 provides the site specific modifications to the mass balance equation and the methodology for calculating volumes of CO_2 sequestered.

- Section 8 provides the estimated schedule for implementation of the MRV plan.

- Section 9 describes the quality assurance program.

- Section 10 describes the records retention process.

1.0 Facility Information

i) Reporter number: 523107
The AGI wells report under the Shute Creek Treating Facility (SCTF) Greenhouse Gas Reporting Program Identification number, which is: 523107.

ii) Underground Injection Control (UIC) Permit Class: Class II
The Wyoming Oil and Gas Conservation Commission (WOGCC) regulates oil and gas activities in Wyoming. Both AGI wells in LaBarge are classified as UIC Class II wells.

iii) UIC injection well identification numbers:

Well Name	AGI 2-18	AGI 3-14
Well Identification Number	4902321687	4902321674

2.0 Project Description

This section describes the planned injection volumes, environmental setting of the LaBarge Field, injection process, and reservoir modeling.

2.1 Geology of the LaBarge Field

The LaBarge field area is located in the southwestern corner of Wyoming, contained in Lincoln and Sublette counties. The producing field area is within the Green River Basin and the field is located due west of the Wind River Mountains along the Moxa Arch (Figure 2.1).

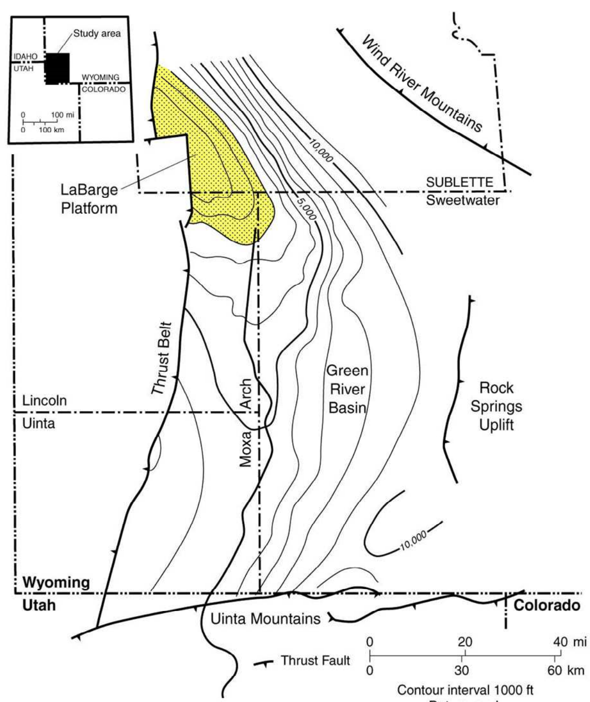

Figure 2.1 Location Map of the LaBarge Field, Wyoming

2.2 Stratigraphy of the Greater LaBarge Field Area

The western region of Wyoming has been endowed in a very rich and prolific series of hydrocarbon reservoirs. Hydrocarbon production has been established or proven from a large number of stratigraphic intervals around Wyoming, ranging from reservoirs from Cenozoic to Paleozoic in age. Figure 2.2 shows a complete stratigraphic column applicable to the Greater Green River Basin in western Wyoming.

For the LaBarge field area, specifically, commercially producible quantities of hydrocarbons have been proven in the following intervals:

- Upper Cretaceous Frontier formation
- Lower Cretaceous Muddy formation
- Permian Phosphoria formation
- Lower Jurassic Nugget formation
- Pennsylvanian Weber formation
- Mississippian Madison formation

2.3 Structural Geology of the LaBarge Field Area

The LaBarge field area lies at the junction of three regional tectonic features: the Wyoming fold and thrust belt to the west, the north-south trending Moxa Arch that provides closure to the LaBarge field, and the Green River Basin to the east. On a regional scale, the Moxa Arch delineates the eastern limit of several regional north-south thrust faults that span the distance between the Wasatch Mountains of Utah to the Wind River Mountains of Wyoming (Figure 2.3).

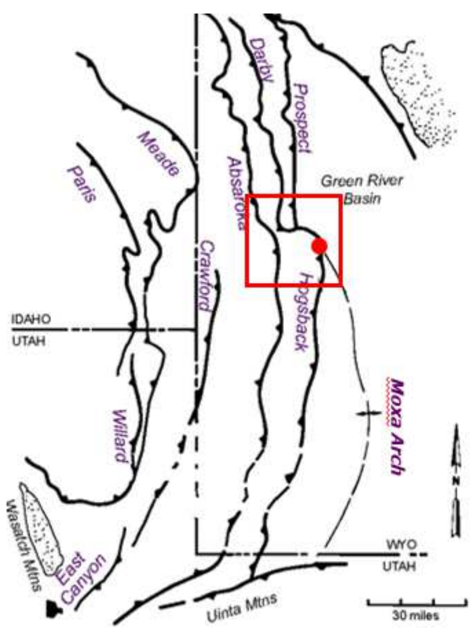

Figure 2.3 Schematic map showing location of Moxa Arch, regional thrust faults. The LaBarge field area is denoted by the red box.

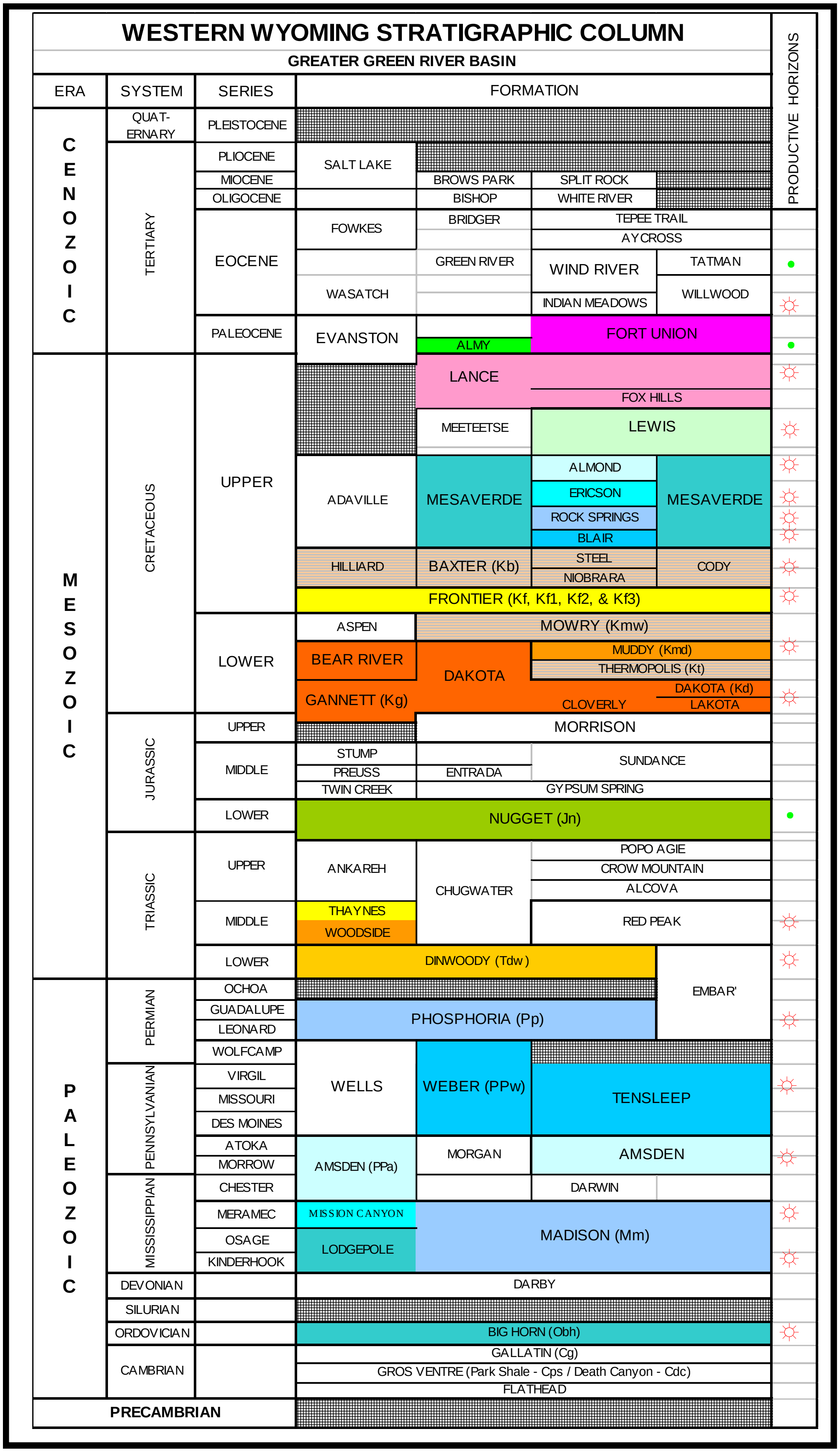

Figure 2.2 Generalized Stratigraphic Column for the Greater Green River Basin, Wyoming

The historical evaluation of structural styles at LaBarge has revealed that three principal styles of structuring have occurred in the area:

- Basement-involved contraction
- Deformation related to flowage of salt-rich Triassic strata
- Basement-detached contraction.

2.3.1 Basement-involved Contraction Events

Basement-involved contraction has been observed to most commonly result in thrust-cored monoclinal features being formed along the western edge of the LaBarge field area (Figure 2.3). These regional monoclinal features have been imaged extensively with 2D and 3D seismic data, and are easily recognizable on these data sets (Figure 2.4). At a smaller scale, the monoclinal features set up the LaBarge field structure, creating a hydrocarbon trapping configuration of the various reservoirs contained in the LaBarge productive section.

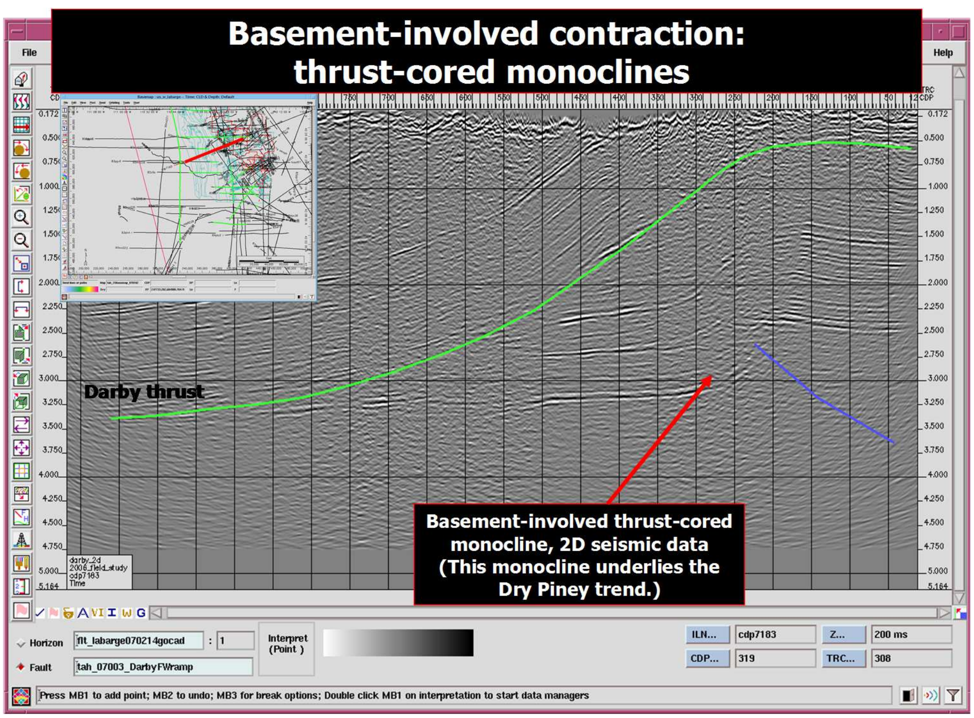

Figure 2.4 Example of thrust-cored monoclinal feature interpreted from 2D seismic data. The thrust-cored feature is believed to be a direct product of basement-involved contractional events.

2.3.2 Deformation of Flowage from Triassic Salt-rich Strata

The second most common style of deformation in the LaBarge field area is the result of flowage from Triassic strata that contain significant amounts of salt. These Triassic sediments have been observed in outcrop to be comprised of interbedded salt and siltstone intervals. At LaBarge, it is not typical to observe thick, continuous sections of pure salt, but rather the interbedded salt and siltstone sections. The ‘salty sediments’ of this interval have been determined to later evacuate and/or flow, which results in local structural highs being developed around these areas. Figure

2.5 shows two seismic lines showing the Triassic salt-rich sediments and the structuring. The salt-induced local structural features generated via salt evacuation can and do create small, local hydrocarbon traps associated with these sediments. These smaller, localized structures are of a much smaller scale than the main monoclinal hydrocarbon trap of the larger LaBarge field.

The active deformation behavior of these Triassic sediments has been empirically characterized through the drilling history of the LaBarge field. Early in the life of many wells drilled at LaBarge, wells drilled with thin-walled casing were observed to fail due to casing shearing across the Triassic interval. Subsequent drilling at LaBarge has necessitated using thicker-walled casing strings to combat the sediment flowage problems.

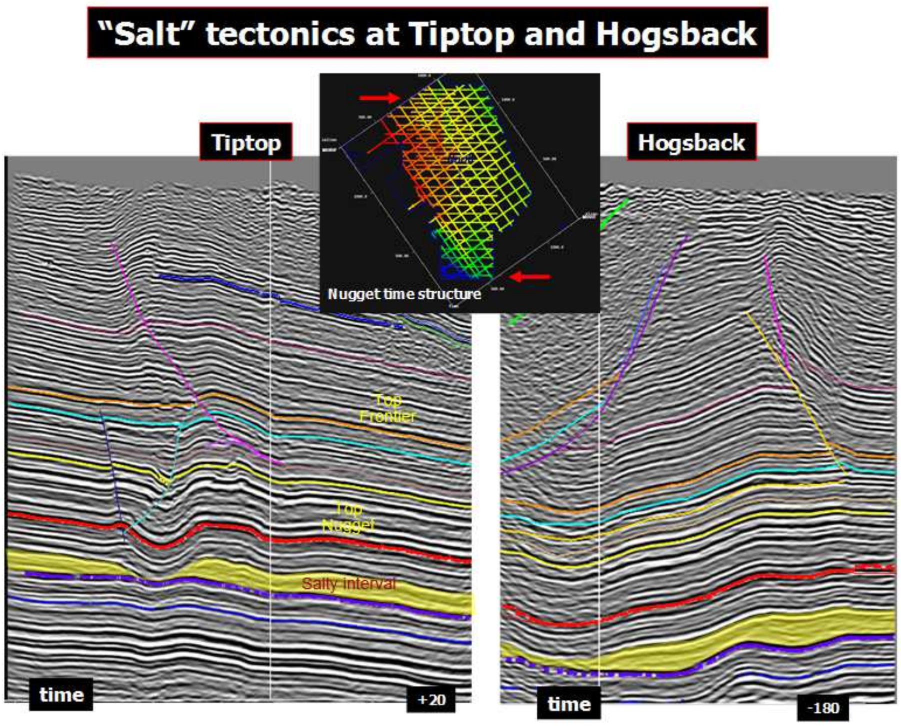

Figure 2.5 Seismic expression of Triassic salt-rich localized sediment structures in the greater LaBarge field area (Data courtesy of CGG and WesternGeco)

2.3.3 Basement-detached Contraction

The third main structural style observed at LaBarge field is those resultant from basement-detached contraction. These features have been well-documented, historically at LaBarge as many of these features have mapped fault expressions on the surface. Detachment and contraction along the basement typically creates three types of structural features:

- Regional scale thrust faults
- Localized, smaller scale thrust faults
- Reactivation of Triassic salt-rich sediments resulting in local structural highs (section 2.3.2.).

The basement-detached contraction features typically occur at a regional scale. The subsurface structural features formed through these contractional events are the same size or larger than the greater LaBarge field area. Very large faults are usually associated with these subsurface features, albeit that the reactivation of Triassic salt sediments which can result in additional localized structuring in the area (section 2.3.2).

2.3.4 Faulting and Fracturing of Reservoir Intervals

Reservoir permeability has been observed to increase with the presence of small-scale faults and fractures in almost all of the productive intervals of LaBarge field. Micro-fractures have been observed in core and on formation micro imager (FMI) logs. The fractures seen in the available core are typically filled with calcite, in general.

Empirically, reservoir permeability and increased hydrocarbon productivity have been observed in wells/penetrations that are correlative to areas located on or near structural highs or fault junctions. These empirical observations tend to suggest that these areas have a much higher natural fracture density than others areas or have a larger proportion of natural fractures that are open and not calcite filled. Lack of faulting in an area, as is observed in the area of the existing AGI wells at LaBarge, tends to yield reservoir permeability that is dominated only by matrix or pore-to-pore flow that is generally inhibitive to fluid flow in the subsurface over long distances.

2.3.5 LaBarge Field Structure and Gas Resource of the Madison Formation

Structural closure on the Madison formation at the LaBarge field is quite large, with approximately 4,000’ true vertical depth (TVD) of structural closure from the top of the structure to the gas-water contact (GWC). Spatially, the Madison closure covers over 1,000 square miles making it one of the largest gas fields in North America.

The Madison is estimated to contain approximately 170 trillion cubic feet (TCF) of raw gas and 20 TCF of natural gas (CH_4). At current rates of production, the estimated remaining field life is over 100 years. Spatially, the Madison injection wells have been located at or immediately adjacent to the SCTF, approximately 30 miles to the southeast from the main LaBarge production areas.

2.4 History of the LaBarge Field Area

The LaBarge field was initially discovered in 1920 with the drilling of a shallow oil producing well. The generalized history of the LaBarge field area is as follows:

- 1907 Oil seeps observed near LaBarge, surface mapping of Tip Top anticline
- 1920 Texas Production Company drills shallow Hilliard sandstone discovery (10 BOPD)
- 1940's General Petroleum (Mobil) explores LaBarge area, surface and seismic mapping

- 1951 Tip Top Field discovered by G.P. (Frontier SS @ 1.8 MCFD, Nugget SS @ 266 BOPD)
- 1952 Belco discovers Frontier gas at Big Piney and LaBarge
- 1954 Belco commits gas to Pacific NW Pipeline, 33 SI gas wells
- 1956 Pacific NW Pipeline completed
- 1956-64 Active drilling of Frontier wells (structural traps)
- 1962 Mobil discovers Madison LS gas at Tip Top, chooses not to develop
- 1970 Exxon evaluates LaBarge area
- 1975-84 2nd major phase of Frontier drilling (stratigraphic traps)
- 1980 Section 29 of Oil Windfall Tax Act for tight gas sands passed (expired 01/01/94)
- 1981 Exxon discovers Madison gas on Lake Ridge Unit (LRU 1-03)
- 1986 First sales of Exxon Madison gas
- 1992 Wyoming Oil & Gas Commission approves 160 acre spacing for Frontier
- 1989-95 Chevron, Enron, PG & E, and Mobil actively drill Frontier targets
- 1999 Exxon and Mobil merge

Historically, Exxon held and operated the Lake Ridge and Fogarty Creek areas of the field, while Mobil operated the Tip Top and Hogsback field areas (Figure 2.6). The heritage operating areas were combined in 1999, with the merger of Exxon and Mobil to form ExxonMobil, into the greater LaBarge operating area. In general, heritage Mobil operations were focused upon shallow sweet gas development drilling while heritage Exxon operations focused upon deeper sour gas production.

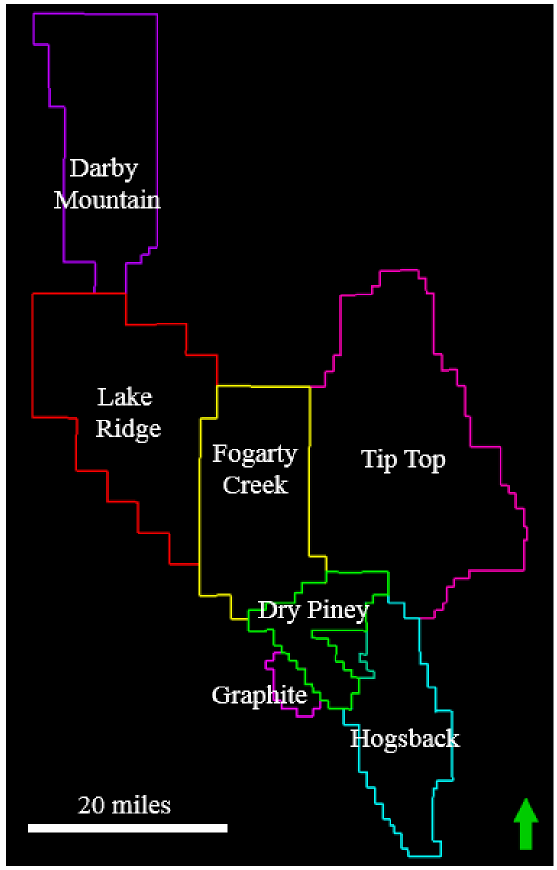

Figure 2.6 Unit map of the greater LaBarge field area

2.5 Initial Discovery of Gas and Early Commercial Production at LaBarge

ExxonMobil's involvement in LaBarge originates in the 1960's with Mobil's discovery of gas in the Madison carbonate formation. The Madison discovery, however, was not commercially developed until much later in the 1980's following Exxon's Madison gas discovery on the Lake Ridge Unit. Subsequently, initial commercial gas production at LaBarge was first established in the Frontier formation, while commercial oil production was established in the Nugget formation.

Gas production from the Madison formation was initiated in 1986 after the start-up of the SCTF, which expanded capacity to handle Madison gas. The total gas in-place for the Madison formation at LaBarge is in excess of 167 TCF gross gas and is a world-class gas reserve that was felt to be economically attractive for production.

2.6 Acid Gas Injection Program History at LaBarge

The Madison formation, once commercial production of gas was established, was found to contain relatively low methane (CH_4) concentration and high carbon dioxide (CO_2) content. The average properties of Madison gas are:

- 21% CH_4
- 66% CO_2
- 7% nitrogen (N_2)
- 5% hydrogen sulfide (H_2S)
- 0.6% helium (He)

Due to the abnormally high CO_2 and H_2S content of Madison gas, the CH_4 was stripped from the raw gas stream leaving a very large need for disposal of the CO_2 and H_2S that remained. For enhanced oil recovery projects (EOR), CO_2 volumes have been historically sold from LaBarge to offset oil operators operating EOR oilfield projects. Originally, the SCTF contained a sulfur recovery unit process to transform the H_2S in the gas stream to elemental sulfur. In 2005, the SRU's were decommissioned to debottleneck the plant and improve plant reliability. This created a need to establish reinjection of the H_2S, and entrained CO_2, to the subsurface.

2.6.1 Geological Overview of AGI Program

Sour gas of up to 66% CO_2 and 5% H_2S is currently produced from the Madison formation at LaBarge. The majority of produced CO_2 is currently being sold by ExxonMobil to other oilfield operators and is being used in EOR projects in the region. The sold volume however, does not equal the total produced CO_2 and H_2S volumes, thereby requiring disposal.

ExxonMobil has pursued the AGI program as a safe and reliable method to re-inject the acid gas into the Madison formation below the field GWC. Gas composition is based on plant injection needs, and will vary between 35 - 50% CO_2 and 50 - 60% H_2S. The gas is injected at a depth of 17,500 feet below the surface and approximately 43 miles away from the main producing areas of LaBarge. Figure 2.7 is a schematic diagram illustrating the AGI program at LaBarge.

2.6.2 Reservoir Quality of Madison Formation in AGI Wells

The existing AGI wells were successfully drilled, logged, and evaluated prior to injection commencement. Figure 2.8 is a schematic of two of the AGI wells (3-14 and 2-18). Petrophysical evaluation of these wells indicate that Madison limestone and dolomite sequences were penetrated, as expected. Total porosity ranges of the limestone sequences were determined to be between 0% and 5%, while the dolomite sequences were found to be up to 20% total porosity. Injection fall-off testing indicated that both wells exhibit greater than 2000 millidarcy-feet (md-ft) of permeability-height within the injection section. Figure 2.9 shows a table summarizing the reservoir properties determined from the 3-14 and 2-18 wells.

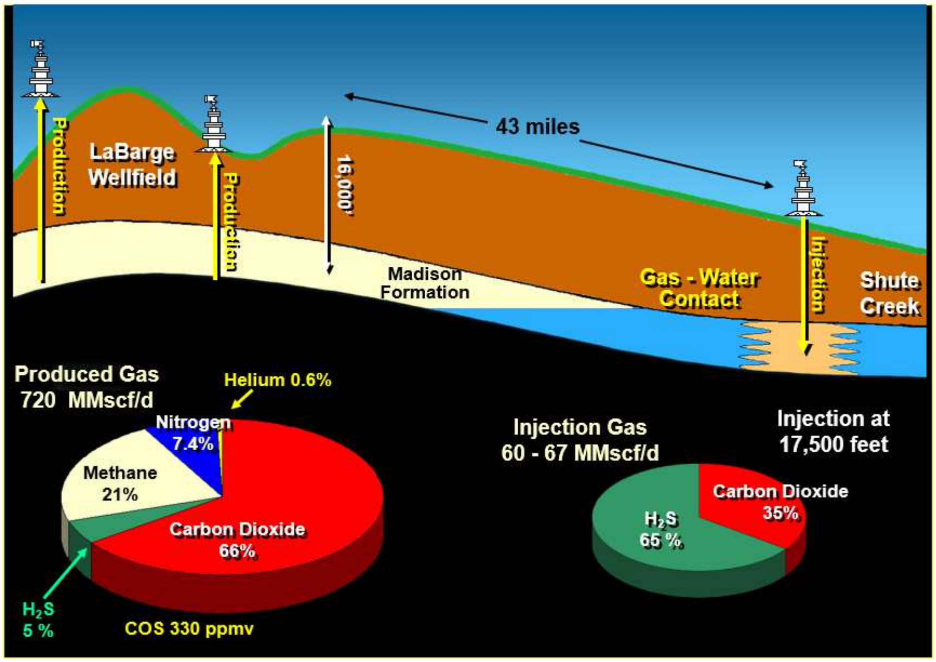

Figure 2.7 Schematic illustration of AGI injection program as currently used at LaBarge

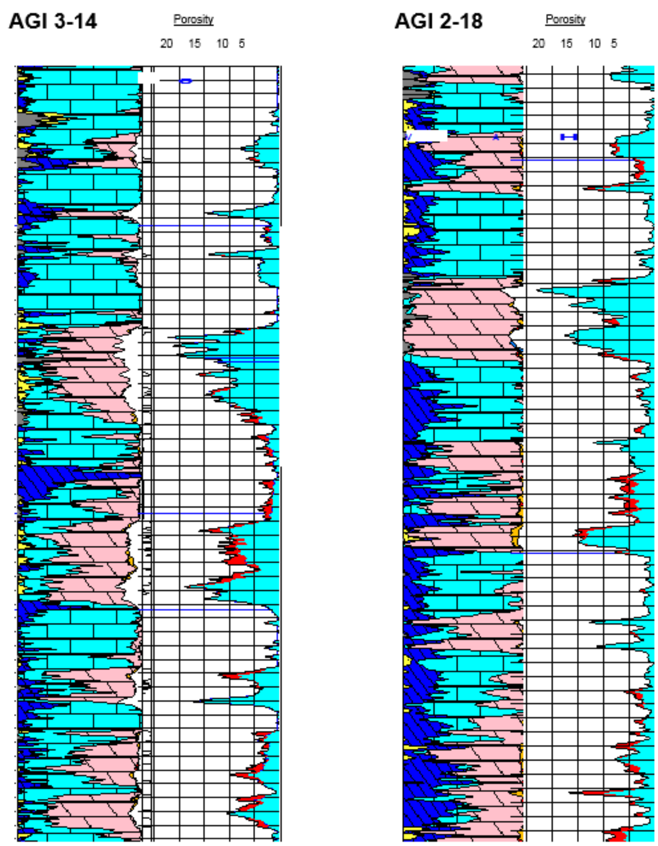

Figure 2.8 Well log sections from the AGI 3-14 and 2-18 injections wells across the Madison formation.

AGI WELLS

	PRE-DRILL	ACTUAL	
		AGI 3-14	AGI 2-18
Net Pay (ft)	210	240	220
Avg ϕ (%)	7%	10%	9%
Avg k (md)	9	9	12
kh (md.ft)	1900	2300*	~2700*
Skin	0	-4.1*	-4.5*

* From injection / falloff test analysis

Figure 2.9 Average reservoir properties of the two AGI wells.

From Figure 2.9, the parameters tabulated include:

- *Net pay:* Madison section that exceeds 5% total porosity.
- *Phi (ϕ):* Total porosity; the percent of the total bulk volume of the rock investigated that is not occupied by rock-forming matrix minerals or cements.
- *K:* Air permeability, which is measured in units of darcy; a measure of the ability of fluids to move from pore to pore in a rock. Note that the measure of darcy assumes linear flow (i.e. pipe shaped).
- *Kh:* Millidarcy-feet, which is a measure of the average permeability calculated at a 0.5 foot sample rate from the well log accumulated over the total net pay section encountered.
- *Skin:* Relative measure of damage or stimulation enhancement to formation permeability in a well completion. Negative skin values indicate enhancement of permeability through the completion whereas positive values indicate hindrance of permeability or damage via the completion.

2.6.3 Seismic Expression of Madison Formation at AGI Well Location

Seismic expression of the Madison formation at the injection location indicates that the injection wells are located on the plunging crest of the Moxa Arch with little to no structuring observable on the seismic data. Faulting is also not indicated by the seismic data. Figure 2.10 shows example lines from the AGI injection area at four times vertical exaggeration.

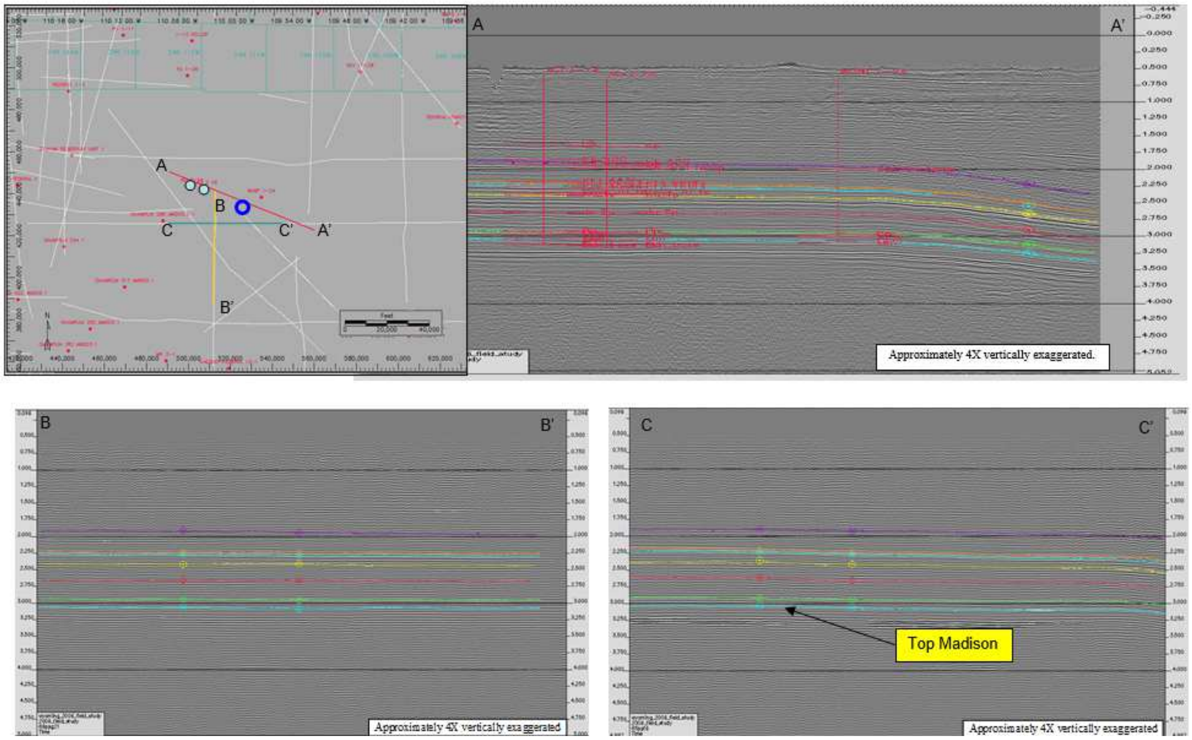

Figure 2.10 Seismic traverses around AGI injection well locations showing no evidence of faulting or structuring around the AGI wells

2.7 Description of the Injection Process

The AGI facility was commissioned for eliminating the Claus Sulfur Recovery Units bottleneck, reducing plant downtime, and reducing operating costs. The purpose of AGI is to take the H_2S and some of the CO_2 removed from the produced raw gas and inject it back into the Madison reservoir. Production of raw gas and injection of acid gas are out of and into the Madison Formation. The Madison reservoir fluid contains very little CH_4 and He at the lower injection locations under SCTF, where the AGI wells are located. Thus, there is no concern of contaminating the production from the LaBarge well field 43 miles away.

The AGI system transports the acid gas stripped in the Selexol process under pressure through a pipeline to two underground wells that are geologically suitable for storage of the acid gas. There are three parallel compressor trains. Two trains are required for full capacity; the third train is a spare. The low pressure feed from the Selexol process enters the first stage suction and is compressed through four stages of compression. The high pressure acid gas from the Selexol process requires only three stages of compression. The fourth stage discharge acid gas must be condensed prior to pumping to prevent damage from vapors. Fourth stage discharge acid gas is cooled in three heat exchangers prior to entering the pump. Dense phase aerial coolers are located downstream of the pumps; they remove heat generated by pumping and increase the density of the fluid. The liquid H_2S/CO_2 is commingled downstream of the dense phase coolers and divided to the two injection wells (3-14 and 2-18). The approximate stream composition being injected is 50 - 65% H_2S and 35 - 50% CO_2.

Each injection well has a dedicated six-inch carbon steel pipeline. The length of pipeline from the AGI battery limit to the injection wells is about:

- 3,200 feet to AGI 3-14
- 12,400 feet to AGI 2-18

The AGI flow lines are buried with seven feet of cover. Heat tracing is provided for the aboveground portions of the lines to prevent the fluid from cooling to the point where free water settles out. Free water and liquid H_2S/CO_2 form acids, which could lead to corrosive conditions. Additionally, the gas is dehydrated before it enters the flow line, reducing the possibility of free water formation, and the water content of the gas is continuously monitored. The liquid H_2S/CO_2 flows via the injection lines to two injection wells. The total depth of each well is about:

- 18,015 feet for AGI 3-14
- 18,017 feet for AGI 2-18.

2.8 Planned Injection Volumes

The below graph is a long-term injection forecast through the life of the injection project. It is based on historic and predicted data. It is important to note that this is just a forecast; actual injection volumes will be collected, calculated, and reported as required by Subpart RR. Additionally, the volumes provided below are the total amount of gas to be injected, not just the CO_2 portion. ExxonMobil forecasts the total volume of CO_2 stored over the modeled injection period to be approximately 37 million metric tons.

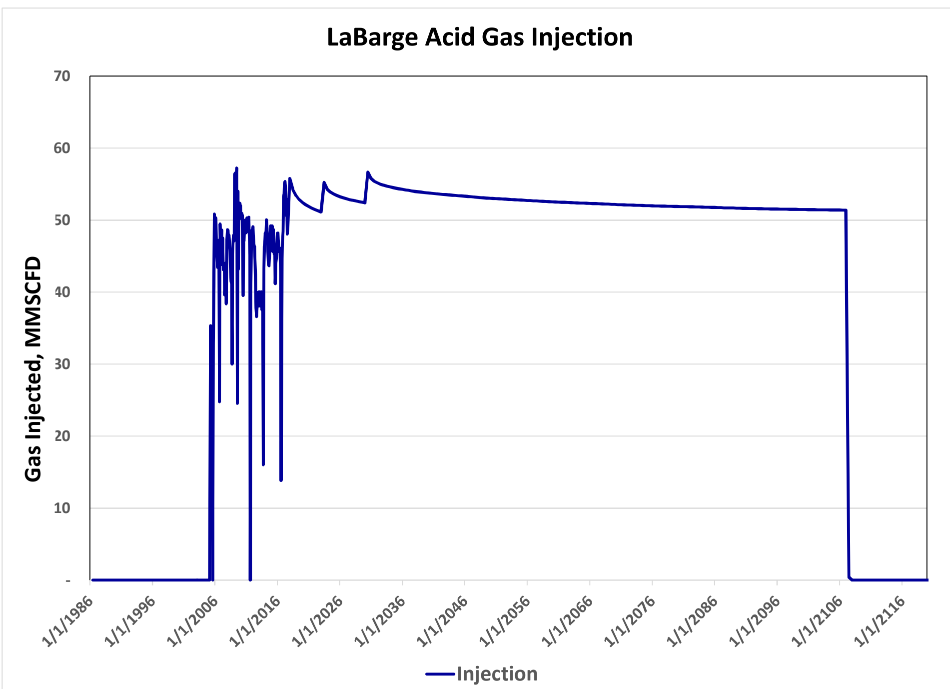

Figure 2.11 – Planned Injection Volumes

3.0 Delineation of Monitoring Area

3.1 Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data, was conducted to predict the size and location of the plume, as well as understand how the plume diameter changes over time.

Calculation of the volume-weighted average gas saturation at various time steps was used to determine the acid gas plume area, with the plume boundary defined as the area with an average gas saturation of greater than 0.5%. A gas saturation of 0.5% is well below the lowest gas saturation that can be confidently detected by formation evaluation methods in reservoirs with rock properties such as those found in the Madison formation.

After injecting 0.2 TCF by year-end 2017, the estimated acid gas plume size is approximately 15,000 feet in diameter (2.84 miles) (see Figure 3.1). With continuing injection of an additional 1.7 TCF through year-end 2106, at which injection is expected to cease, the plume size is expected to grow to approximately 36,000 feet in diameter (6.82 miles) (see Figure 3.2). Figure 3.3 shows how the predicted plume average diameter is expected to change over time. The model was run through July 2986 to assess the potential for expansion of the plume after acid gas injection ceases. Starting around the post-injection time frame, plume diameter growth slows and begins to plateau. Expansion of the plume to a diameter of approximately 42,000 feet (7.95 miles) occurs by the year 2500 as the gas plume settles due to gravity segregation and dispersion. The plume is expected to continue settling, with a modeled plume size of approximately 44,000 feet (8.33 miles) by July 2986, 1000 years after production of the LaBarge field started and over 800 years after injection was shut-in. At this point, the rate of movement of the free-phase gas plume has decreased to less than four feet per year, demonstrating plume stability. Therefore, the MMA will be defined by Figure 3.4, which is the maximum areal extent of the plume once it has reached stability (defined by the extent of the plume in July 2986, which is an 8.3-mile diameter) plus the buffer zone of one-half mile.

3.2 Active Monitoring Area (AMA)

ExxonMobil proposes to define the AMA as the same boundary as the MMA. The following factors were considered in defining this boundary:

- Lack of faulting in the MMA yields no vertical pathways for fluids to move vertically out of the Madison to shallower intervals.
- Lack of faulting in the injection area does not create enhanced reservoir permeability through natural fracturing and all flow of injected fluids will be darcy flow from pore to pore.
- Distance from the LaBarge production field area is large (30 miles) and formation permeability is generally low which naturally inhibits flow aerially from injection site.

- The LaBarge field production area is a large structural hydrocarbon trap that has sealed and trapped hydrocarbons for large geologic periods of time. There is no reason to believe that any injection fluids that may migrate outwards from the injection site to the larger LaBarge structure would not also be effectively trapped at the LaBarge structure over geological time.

The purpose of the AMA is to allow for a practical and cost-effective monitoring program throughout the life of the project. Because there are no probable leakage pathways in the maximum monitoring area, besides surface equipment which is extensively monitored, ExxonMobil believes it is appropriate to define the AMA as the same boundary as the MMA. Additionally, due to the high H_2S content of the injected gas stream, monitoring of leaks is essential to operations and personnel safety, so a full-scale monitoring program has already been implemented at the AGI sites, as will be discussed below.

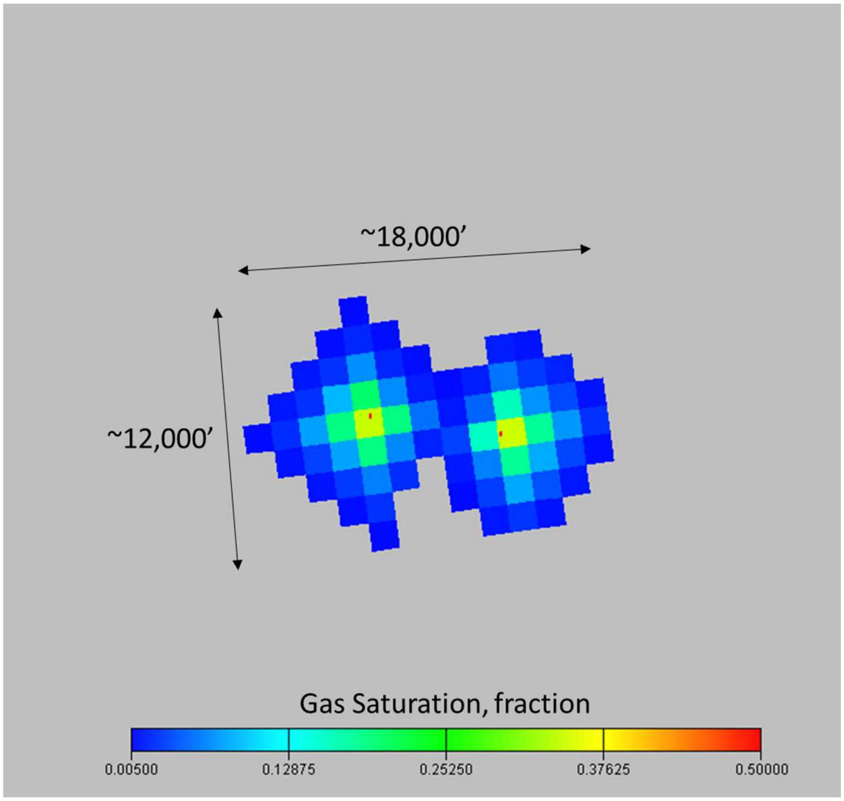

Figure 3.1 – AGI Gas Saturations at Year-end 2017

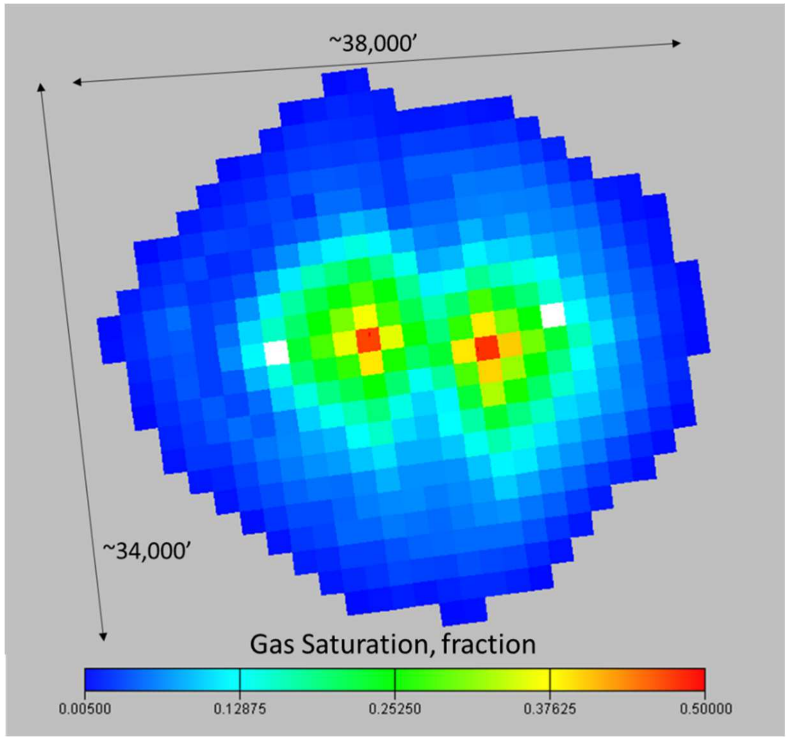

Figure 3.2 – AGI Gas Saturations at Year-end 2106

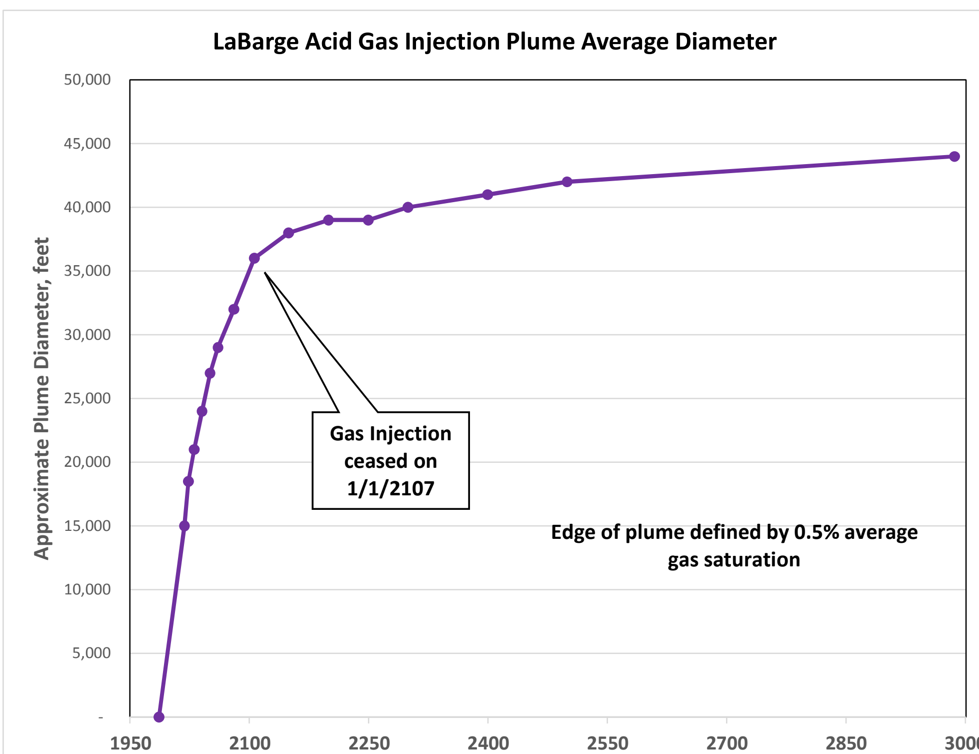

Figure 3.3 – Predicted LaBarge AGI Plume Diameter

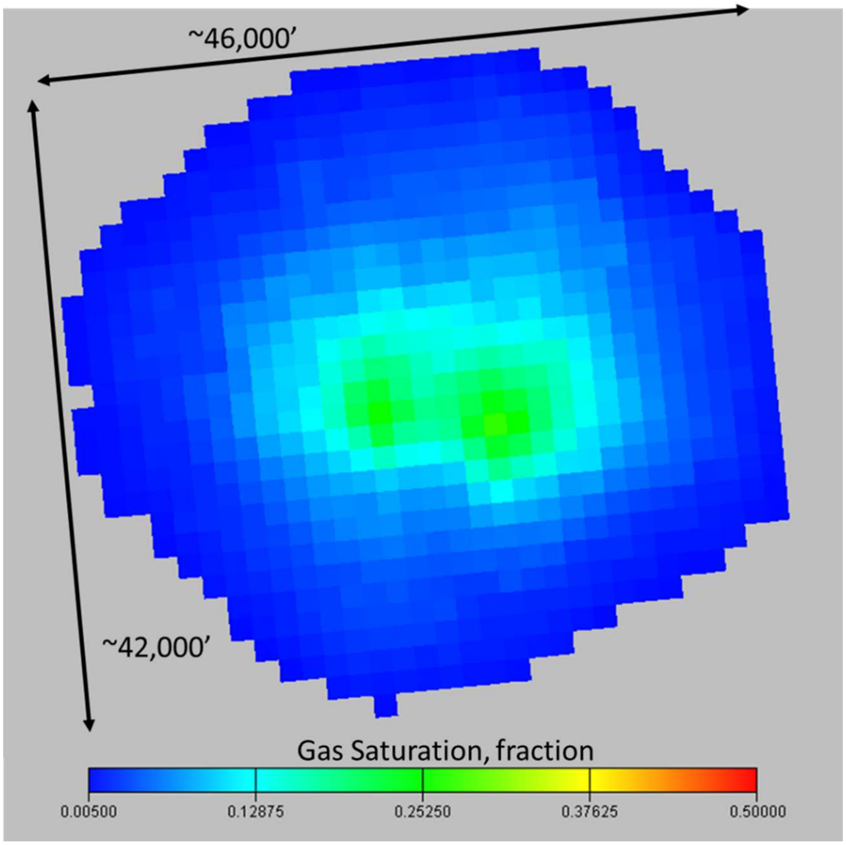

Figure 3.4 – AGI Gas Saturations at Year-end 2986

4.0 Evaluation of Potential Pathways for Leakage to the Surface

This section assesses the potential pathways for leakage of injected CO_2 to the surface. ExxonMobil has identified the potential leakage pathways within the monitoring area as:

1. Leakage from surface equipment (pipeline and wellhead)
2. Leakage through wells
3. Leakage through faults and fractures
4. Leakage through the seal

As will be demonstrated in the following sections, there are no leakage pathways that are likely to result in loss of CO_2 to the atmosphere. Further, given the relatively high concentration of H_2S in the injection stream, any leakage through identified or unexpected leakage pathways would be immediately detected by alarms and addressed, thereby minimizing the amount of CO_2 released to the atmosphere.

4.1 Leakage from Surface Equipment

Leakage from surface equipment is not likely due to the design of the AGI facilities. The AGI facilities were designed to minimize leak points such as valves and flanges, and use welded connections where possible instead. The only surface equipment located between the flow meter

and the wellhead are valves, transmitters, and flanged connection points on the pipelines. Due to the presence of H_2S in the injection stream at a concentration of 50 - 65% (500,000 - 650,000 ppm), H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons, which alarm at 5 ppm. Although damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2 entrained in the acid gas, at this relative concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm, and immediate action would be taken to stop the leak. Accordingly, in the unlikely event of such a leak, its magnitude would be small.

ExxonMobil reduces the risk of unplanned leakage from surface facilities through continuous surveillance, facility design, and routine inspections. Field personnel monitor the AGI facility continuously through the distributed controls system (DCS). Additionally, daily visual inspection rounds are conducted of the AGI facility and weekly visual inspections rounds are conducted of the AGI wells, which provide an additional way to detect leaks in a timely manner. ExxonMobil also relies on the prevailing design of the facility, which includes wells with surface controlled subsurface safety valves (SCSSV's), which are set to trip closed if leakage is detected. This would eliminate any backflow out from the formation, minimizing leakage volumes. Additionally, the wells have multiple surface isolation valves for redundant protection if there are any issues with the SCSSV's. Inline inspections of the injection pipelines using a smart pigging tool are conducted on a regular frequency to check the wall thickness of the pipeline to identify potential areas of corrosion.

Should leakage be detected from surface equipment, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

4.2 Leakage through Wells

Leakage of CO_2 through oil, gas, and/or water wells completed and/or abandoned is not likely. There is no commercial production of oil or gas within the immediate area of the SCTF. There is shallower production of gas from the Frontier and Dakota formations nearby in the Cow Hollow Field, at depths of 10,800' – 11,800'. A search of the WOGCC database demonstrated that there are no existing Madison penetrations or production within the MMA other than the AGI wells. The nearest established Madison production is greater than 30 miles to the north-northwest in the ExxonMobil LaBarge Deep Madison Field, which is the well field that supplies SCTF. One well (Whiskey Butte Unit 1 operated by Wexpro Company), which was located approximately six miles from the AGI wells, was drilled to the Madison formation back in 1974. However, the well never produced from the Madison formation and instead was perforated and had casing installed thousands of feet above in the Frontier formation. The well was ultimately plugged and abandoned in February 1992 and does not pose a risk as a leakage pathway. Two additional Madison penetrations are located between the well field and the AGI wells; both penetrations are outside the boundary of the MMA and therefore do not pose a risk as a leakage pathway. Keller Rubow 1-12 was P&A'd in 1996. Fontenelle II Unit 22-35 was drilled to the Madison formation but currently is only perforated and producing from thousands of feet above in the Frontier formation.

ExxonMobil reduces the risk of unplanned leakage from the injection wells through continuous surveillance of injection parameters, routine inspections, and mechanical integrity testing (MIT). As indicated in Section 4.1, visual inspections of the well sites are performed on a weekly basis, which serves as a proactive and preventative method for identifying leaks in a timely manner. Gas detectors are located at the well sites which alarm at 10 ppm H_2S and would be triggered if a leak from the wellbore to the atmosphere occurred. Additionally, SCSSV's and surface isolation valves are installed at the wells, which would close in the event of leakage, preventing losses. Mechanical integrity testing is conducted on an annual basis and consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. If MIT demonstrated a leak, the well would be isolated and the leak would be mitigated as appropriate to prevent leakage to the atmosphere.

Should leakage result from the injection wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on the operating conditions at the time of release.

4.3 Leakage through Faults and Fractures

As discussed in Section 2.6.3, engineering and geologic analysis show no evidence of faulting or structuring around the AGI wells. As a result, the risk of leakage through this pathway is highly improbable. The absence of faulting also tends to suggest that natural fracturing or permeability enhancement in the Madison is also highly improbable.

Prior to drilling the AGI wells, ExxonMobil worked with multiple service companies who provided a range of fracture gradients for the Phosphoria, Weber/Amsden, Morgan, and Madison Formations in the area. Based on a frac gradient of 0.85 pounds per square inch (psi)/foot for the Madison, 0.82 psi/foot for the Morgan, 0.80 psi/foot for the Weber/Amsden, and 0.775 psi/foot for the Phosphoria Formation, and a downhole fracture pressure of 12,167 psi, which corresponds to a surface injection pressure of ~5,500 psi, the injected acid gas will not initiate fractures in the confining zones of overlying strata. Facility limits exist that limit surface pressures to below 3,200 psi, which is well below the pressure required to fracture the formation; therefore, probability of fracture is unlikely.

4.4 Leakage through the Formation Seal

Leakage through the seal of the Madison reservoir is highly improbable. An ultimate top seal to the disposal reservoir is provided by the evaporitic sequences within the Thaynes Formation. In fact, the natural seal is the reason the reservoir exists in the first place – the gas has been trapped in the LaBarge structure over a large amount of geologic time. The rock that forms the natural seal is impermeable to He, a gas with a much smaller molecular volume than CO_2. If the reservoir seal material is impermeable to He, then it follows that it is also impermeable to CO_2. The Thaynes Formation's sealing effect is also demonstrated by the fact that all gas production shallower than the Thaynes is void of sour gas, while all gas production below it is enriched in sour gases.

The acid gas wells are monitored to ensure that the injected gases stay sequestered. Any escaped CO_2 will be associated with H_2S, which has the potential to cause injury to ExxonMobil employees. The CO_2 injected at SCTF cannot escape without immediate detection, as expanded upon in the below sections.

5.0 Detection, Verification, and Quantification of Leakage

5.1 Leakage Detection

As part of ongoing operations, SCTF continuously monitors and collects flow, pressure, temperature, and gas composition data in the DCS. These data are monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. Additionally, SCTF maintains in-field gas detectors to detect H_2S in the vicinity. If one of the gas detectors alarmed, it would trigger an immediate response to address the situation. In some instances, more than one detector alarming will trigger automatic equipment isolation/shutdown to mitigate the leak.

Leakage detection for the AGI wells will incorporate several monitoring programs including visual inspection of the surface facilities and wellheads, injection well monitoring and MIT, and Distributed Control System (DCS) surveillance. Table 5.1 provides general information on the leakage pathways, monitoring programs to detect leakage, and location of monitoring. Monitoring will occur for the duration of injection. As will be discussed in Section 7.0 below, ExxonMobil will quantify equipment leaks by using a risk-driven approach and continuous surveillance.

Table 5.1 - AGI Monitoring Programs

Leakage Pathway	Detection Monitoring Program	Monitoring Location
Surface Equipment	DCS Surveillance Visual Inspections Inline Inspections Gas Alarms Personal H_2S Monitors	From injection flow meter to injection wellhead
Wells	DCS Surveillance Visual Inspections MIT Gas Alarms Personal H_2S Monitors	Injection well – from wellhead to injection formation

Faults and Fractures, Formation Seal	N/A – Leakage pathway is highly improbable	N/A

5.2 Leakage Verification

Responses to leaks are covered in the facility's Emergency Contingency Plan. If there is report or indication of a leak from visual observation, gas monitors, pressure drop, etc., the area will be evacuated and isolated. A two-man control and countermeasure team will be dispatched with emergency breathing air equipment and gas monitors to investigate the area and locate the leak. Local wind speed, direction, and H_2S monitors will be used to determine the potentially affected areas. Emergency shutdown systems will be utilized as necessary to isolate the leak. Pressure from the system will be relieved to the flare, not vented, due to the dangerous composition of the gas.

5.3 Leakage Quantification

The leakage from surface equipment will be estimated once leakage has been detected and confirmed. Leakage quantification will consist of a methodology selected by ExxonMobil. Leakage estimating methods may potentially consist of modeling or engineering estimates based on operating conditions at the time of the leak such as temperatures, pressures, volumes, hole size, etc.

6.0 Determination of Baselines

ExxonMobil uses existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. The following describes ExxonMobil's approach to collecting baseline information.

Visual Inspections

Field personnel conduct daily inspections of the AGI facilities and weekly inspections of the AGI well sites. Visual inspections allow issues to be identified and addressed early and proactively, which will minimize the possibility of CO_2 leakage. If an issue is identified, a work order will be generated to correct the issue.

H_2S Detection

The CO_2 injected into the AGI wells is injected with H_2S at a concentration of 50 - 65% (500,000 - 650,000 ppm). H_2S gas detectors are prevalent around the AGI facility and well sites, which alarm at 10 ppm. At this high of a concentration of H_2S, even a miniscule amount of gas leakage would trigger an alarm. Additionally, all field personnel are required to wear H_2S monitors for safety reasons. Personal monitors alarm at 5 ppm. Any gas detector alarm or personal H_2S monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the gas detectors and monitors are working correctly.

Continuous Parameter Monitoring

The DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat.

Well Testing

On an annual basis, the AGI subsurface and wellhead valves are leak tested for mechanical integrity testing as required by the WOGCC. This consists of pressuring up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. Results from this type of testing are compared to previous MIT data to evaluate whether well integrity has been compromised.

Additionally, inline inspections are conducted of the AGI flow lines through the use of a smart pig to identify potential areas of corrosion in the pipeline. Results from this type of testing are compared to previous data to evaluate whether pipeline integrity has been compromised.

7.0 Site Specific Modifications to the Mass Balance Equation

To accommodate for site-specific conditions, as provided in 40 CFR 98.448, ExxonMobil proposes to modify quantifying equipment leaks by using a risk-driven approach. Due to the high H_2S concentration of the AGI fluids, monitoring poses a risk to personnel. Additionally, as mentioned above, even a small leak of this high H_2S gas would trigger an alarm. ExxonMobil identifies leaks through continuous surveillance and alarms, which drive operations to take immediate action to stop the release. This continuous surveillance using gas detectors identifies leaks better than an annual leak survey would due to the fact that the gas detectors are in operation at all times. Fugitive leakage would be detected and managed as an upset event and calculated for that event based on operating conditions at that time.

Below describes how ExxonMobil will calculate the mass of CO_2 injected, emitted, and sequestered.

7.1 Mass of CO_2 Received

§98.443 states that "you must calculate the mass of CO_2 received using CO_2 received equations… unless you follow the procedures in §98.444(a)(4)". §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." Since the CO_2 received by the AGI process is wholly injected and not mixed with any other supply of CO_2, the annual mass of CO_2 injected would be equal to the annual mass of CO_2 received. No CO_2 is received in containers.

7.2 Mass of CO_2 Injected

Volumetric flow meters are used to measure the injection volumes at each well. Equation RR-5 will be used to calculate the annual total mass of CO_2 injected. Equation RR-6 will be used to aggregate injection data for wells 2-18 and 3-14.

7.3 Mass of CO_2 Produced

The AGI wells are not part of an enhanced oil recovery process, therefore, there is no CO_2 produced and/or recycled.

7.4 Mass of CO_2 Emitted by Surface Leakage and Equipment Leaks

It is not appropriate to conduct a leak survey in AGI due to the components being unsafe-to-monitor. Entry into AGI requires the individual to don a full face respirator supplied to breathing air, which would make completion of a leak survey very difficult. Due to the high H_2S concentration of the AGI fluids, fugitive leakage would be detected and managed as an upset event in the same way that CO_2E (CO_2 emitted by surface leakage) would be detected and managed. Fugitive leakage would be managed as an upset event and calculated based on operating conditions at that time. As already mentioned, gas detectors are in operation continuously to survey the area for leaks; even a small leak of this high H_2S gas would trigger an alarm. This methodology is consistent with 40 CFR 98.448(5), which provides the opportunity for an operator to calculate site-specific variables for the mass balance equation.

Therefore, parameters CO_2E and CO_2FI will be measured using the leakage quantification procedures described earlier in this plan. ExxonMobil will estimate the mass of CO_2 emitted from leakage points from the flow meter to the injection wellhead based on operating conditions at the time of the release – pipeline pressure and flow rate, size of the leakage point opening, and estimated duration of leak. There are no CO_2 emissions from venting due to the high H_2S concentration of the injected gas; blowdown emissions are sent to the flares and are reported under Subpart W for the gas plant.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since ExxonMobil is not actively producing oil or natural gas or any other fluids as part of the AGI process, Equation RR-12 will be used to quantify CO_2 sequestered. Parameter CO_2I will be determined used Equation RR-4, as outlined above in Section 7.2. Parameters CO_2E and CO_2FI will be measured using the leakage quantification procedure described above in Section 7.4. CO_2 in the AGI fluids is not vented from equipment due to the high H_2S concentration.

8.0 Estimated Schedule for Implementation of MRV Plan

The SCTF AGI facility and wells have been operational since 2005 and have been following most of the monitoring procedures outlined in this plan since then. ExxonMobil will begin reporting under Subpart RR beginning January 1, 2018 and the GHGRP submittal will occur on or before March 31 of the following year. ExxonMobil anticipates the MRV program will be in effect until the end-of-field-life of the LaBarge assets. At the time of cessation of injection, ExxonMobil will prepare a demonstration supporting the long-term containment determination and submit a request to discontinue reporting under this MRV plan consistent with 40 CFR 98.441(b)(2)(ii).

9.0 Quality Assurance Program

9.1 Monitoring QA/QC

In accordance with the applicable requirements of 40 CFR 98.444, ExxonMobil has incorporated the following provisions into its QA/QC programs:

CO_2 *Injected*

- The flow rate of CO_2 injected is measured with a volumetric flow meter for each injection well and is monitored continuously, allowing the flow rate to be compiled quarterly.
- The injected CO_2 stream will be measured upstream of the volumetric flow meter at the three AGI compressors, at which measurement of the CO_2 is representative of the CO_2 stream being injected, with a continuous gas composition analyzer.
- The continuous composition measurements will be averaged over the quarterly period to determine the quarterly CO_2 composition of the injected stream.
- The CO_2 analyzers are calibrated according to manufacturer recommendations.

CO_2 *emissions from equipment leaks and vented emissions of* CO_2

- Gas detectors are operated continuously except as necessary for maintenance and calibration
- Gas detectors will be operated and calibrated according to manufacturer recommendations and API standards

Measurement Devices

- Flow meters are operated continuously except as necessary for maintenance and calibration
- Flow meters are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i)
- Flow meters are operated according to an appropriate standard method published by a consensus-based standards organization
- Flow meter calibrations are traceable to National Institute of Standards and Technology (NIST)

General

- The CO_2 concentration is measured using continuous gas analyzers, which is an industry standard practice.
- All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data Procedures

In the event ExxonMobil is unable to collect data needed for the mass balance calculations, 40 CFR 98.445 procedures for estimating missing data will be used as follows:

- If a quarterly quantity of CO_2 injected is missing, it will be estimated using a representative quantify of CO_2 injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures will be followed in accordance with those specified in subpart W of 40 CFR Part 98.

9.3 MRV Plan Revisions

If any of the changes outlined in 40 CFR 98.448(d) occur, ExxonMobil will revise and submit the MRV plan within 180 days to the Administrator for approval.

10.0 Records Retention

ExxonMobil will follow the record retention requirements of 98.3(g). Additionally, it will retain the following records for at least three years:

- Quarterly records of injected CO_2 including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.