Preliminary Assessment Of Post-combustion Capture Of Carbon Dioxide At The San Juan Generating Station

An Independent Assessment of a Pre-feasibility Study Conducted by Sargent & Lundy for Enchant Energy

12 December 2019
Los Alamos National Laboratory
Los Alamos, New Mexico 87545

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The assessment was conducted by a team of scientists and engineers at Los Alamos and was supported by the U.S. Department of Energy Office of Fossil Energy

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1. Executive Summary

This is a preliminary technical assessment of a proposal to retrofit the San Juan Generating Station in New Mexico, capturing the carbon dioxide (CO_2) generated by the power plant and transporting it via pipeline to the Permian Basin in Texas for use in CO_2 enhanced oil recovery (CO_2-EOR). The assessment was conducted for the U.S. Department of Energy and relies on publicly available information, including a pre-feasibility study developed by Enchant Energy in partnership with Sargent & Lundy. It is focused on technical aspects of the project as related to the proposed capture of CO_2, the proposed use/storage of CO_2, and potential future options for use/storage of CO_2 in the Four Corners region.

With respect to CO_2 capture, the assessment found that the proposed plan to use an amine-based capture system is a technically viable option that is commercially available and that has been demonstrated to reliably provide ≥90% CO_2 capture out of a continuous flue gas stream. If all of the current emissions were to be processed by the facility, it could theoretically capture ~7 million metric tons CO_2 per year (*i.e.*, assuming the theoretical maximum capacity factor of 100%). The design of the system relies on energy derived from the existing operating units and considers several strategies to optimize efficiency; the use of energy to drive the capture facility results in a derating of the original 914 MW_{gross} to 601 MW_{net}. There appear to be no significant technical issues at the pre-feasibility stage in the context of space, access pipeline, water, or system integration. The pre-feasibility engineering design also considers strategies to utilize existing components of two decommissioned power-generation units, lowering the capital costs.

The assessment found that the amount of CO_2 captured by the amine facility can be tuned and will depend on the CO_2 demand for use (or storage). Although amine-based capture facilities can operate at ≥90% capture, the amount of flue gas processed can be varied in response to CO_2 demand. When this occurs, the net CO_2 captured can be less than 90%. In order to meet requirements associated with the NM Energy Transition Act, the net CO_2 captured would need to be roughly ≥54%; in other words, 90% capture is not needed to comply with the Energy Transition Act. There is an extensive monitoring effort within the Four Corners region that can be leveraged to provide a baseline of pre-existing emission and to confirm emission reductions.

The assessment found that the proposed use of CO_2 for EOR operations in the Permian Basin would have sufficient capacity to store the emissions associated with the projected volumes of captured CO_2 from the power plant. Further, the assessment found that replacement of natural CO_2 sources (which are currently being used) with CO_2 captured from the power plant could result in a net reduction in life-cycle CO_2 relative to conventionally produced oil. The assessment noted the proposed use of the Cortez pipeline would require displacement of naturally produced CO_2 from reservoirs owned by the pipeline owner.

Finally, the assessment considered several potential options for future use/storage of the CO_2 in the Four Corners region, including CO_2-EOR, geologic storage, and the potential to combine captured CO_2 with renewable sources to produce feedstocks for fuel and/or other products.

2. Introduction

2.1 Focus of Assessment

This report documents a preliminary technical assessment of a proposal to retrofit the San Juan Generating Station in New Mexico, capturing the carbon dioxide (CO_2) generated by the power plant and transporting it via pipeline to the Permian Basin in Texas for use in CO_2 enhanced oil recovery (CO_2-EOR). The assessment relies on publicly available information, including a pre-feasibility study developed by Enchant Energy in partnership with Sargent & Lundy.

The assessment was conducted for and supported by the U.S. Department of Energy Office of Fossil Energy. It was independent from Enchant Energy and Sargent & Lundy, although information was shared by these entities with the team at Los Alamos.

Our analysis is not a detailed engineering assessment nor is it based on a detailed engineering plan. It is based largely on a pre-feasibility assessment by Sargent & Lundy, which was in turn based on detailed technical information from suppliers and Sargent & Lundy's extensive experience in these types of systems. In addition, we rely on relevant publicly available information (*e.g.*, reports, presentations, publications) as well as the technical experience of our team, which spans a range of scientific and engineering aspects of CO_2 capture and storage. Finally, we use background information on the field experience with amine-based capture systems provided during discussions with experts from Mitsubishi Heavy Industries (MHI).

Our goal is to provide an independent technical assessment of the conclusions of the Sargent & Lundy study specifically and the proposed project in general. Our analysis focuses on three overarching aspects:

- Capture of CO_2 at the Power Plant—What is the technical readiness of the proposed post-combustion capture process? What is the difference in this approach relative to other capture strategies (*e.g.*, pre-combustion capture)? What are the expected capture efficiency and performance of the amine-based solvents? What technical concerns might be anticipated? What are the likely emissions, and how can they be monitored to verify performance?
- Use of CO_2 in Enhanced Oil Recovery—What is the expected accumulation and retention of CO_2 when used for enhanced oil recovery (*e.g.*, the CO_2 lifecycle)? What is the projected market for CO_2 in the context of EOR in the Permian Basin (*i.e.*, is there sufficient projected need for the future captured emissions at the power plant)? What is the projected future pipeline availability?
- Opportunities for Potential Use and/or Storage of CO_2 in the Four Corners Area. What are the regional opportunities for use of CO_2 in recovery of hydrocarbons and/or long-term storage? What are the regional opportunities for "green" uses of CO_2?

We did not assess the non-technical aspects of the proposed project, such as costs, financing, regulatory position, etc.

2.2 San Juan Generating Station Background

The San Juan Generating Station (SJGS) is located in northwestern New Mexico near the city of Farmington.

The facility is an 847 MW_{net} (914 MW_{gross}) coal-fired power plant that currently consists of two remaining operational units—Unit 1 (340 MW_{net}) and Unit 4 (507 MW_{net}) (Gannon, 2016; Sargent & Lundy, 2019). Two of the original units (Units 2 & 3) have been retired but many of their components remain in place. Units 1 & 4 are the focus of a proposed retrofit to CO_2 (Sargent & Lundy, 2019); they date from the early 1970s and 1980s, respectively, but they have recently been upgraded to include technology to lower emissions of nitrogen oxides, sulfur dioxide, and mercury (Gannon, 2016).

Units 1 & 4 utilize bituminous coal from the San Juan Coal Company (Sargent & Lundy, 2019).

The facility is subject to the New Mexico Energy Transition Act, which will limit CO_2 emissions from electric generating facilities exceeding 300 MW to no more than 1,100 pounds CO_2 per megawatt-hour (MWh) by 1 January 2023 (Energy Transition Act, 2019).

Enchant Energy commissioned Sargent & Lundy to conduct a pre-feasibility study to assess the potential for retrofitting Units 1 & 4 with CO_2 capture technology to address the requirements of the New Mexico Energy Transition Act (Sargent & Lundy, 2019). The U.S. Department of Energy (USDOE) recently awarded funding to a team led by Enchant Energy to support a more extended front-end engineering and design (FEED) assessment of the retrofit plan.[1] The FEED study remains to be conducted at the time of the assessment presented in this report, but it is anticipated to provide a more detailed engineering and economic analysis of the retrofit facility.

3. CO_2 Capture

3.1 Overview

Two primary approaches have been pursued for capturing emissions associated with the burning of coal to produce power, depending on the type of power plant: pre-combustion capture and post-combustion capture.

Pre-combustion capture—which is *not* applicable to the situation at the San Juan Generating Station—targets CO_2 produced in a new type of power plant based on integrated gasification and combined cycle (IGCC). IGCC power plants have been explored as a technology for producing electricity and/or hydrogen at high efficiencies from coal. In an IGCC power plant, coal is converted to a synthetic gas mixture at elevated pressure and temperature, ultimately resulting in a mixture of CO_2 and hydrogen. The CO_2 can be separated leaving the hydrogen which can be used to produce electricity by burning in a turbine or via a fuel cell. Because pre-combustion

[1] https://www.energy.gov/fe/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas

capture relies on relatively new technology for both the energy conversion and CO_2 capture, it is generally at a lower level of technology readiness than post-combustion capture. Indeed, pre-combustion capture at an IGCC facility remains to be demonstrated at an operational power plant scale. Current U.S. Department of Energy research efforts in pre-combustion capture can be found at https://netl.doe.gov/coal/carbon-capture/pre-combustion.

Post-combustion capture—as is being proposed at the San Juan Generating Station involves removing CO_2 from the flue gas emitted from a conventional power plant. In a conventional power plant, coal (or other carbon-based fuel) is combusted to produce steam, which is then used to drive a turbine to produce electricity. The combusted coal results in a flue gas that typically consists of 5–15% CO_2, with the balance being nitrogen, oxygen, and small amounts of various pollutants (*e.g.*, particulates, sulfur oxides or SO_x, nitrogen oxides or NO_x, mercury, etc.). This flue gas can be routed to various processes for removal of the pollutants. Additionally, following removal of pollutants, the flue gas can be routed to a capture process where the CO_2 is separated from the other remaining gases; processing of flue gas to remove CO_2 can require an even higher level removal of other pollutants than is required by some regulations due to undesirable interactions of the pollutants with the CO_2 capture process.

Various processes are being explored for post-combustion capture of CO_2, spanning a range of technology readiness levels, including as part of an active research program within the U.S. Department of Energy (see https://netl.doe.gov/coal/carbon-capture/post-combustion). The proposed retrofit at SJGS is considering a capture technology that is at a high level of technology readiness, specifically amine-based capture (which is commercially available). Amine-based CO_2 capture is a mature technology that has been used industrially for CO_2 separations since 1930 (Bottoms, 1930). Post-combustion capture using amine-based systems is currently being demonstrated at power plants in Texas and Canada as well as at numerous other types of industrial facilities at different scales (Hirata et al., 2018).

3.2 Pre-Combustion Capture at the Kemper Project

Although pre-combustion capture is not being proposed at the San Juan Generating Station, a brief review of the experience with pre-combustion capture at the Kemper Project is warranted for completeness.

It is important to note that the experience at the Kemper project is *not* relevant from a technical standpoint to a retrofit based on amine-based CO_2 capture technology applied to an existing conventional (boiler-based) coal-fired power plant.

The Kemper Project near Meridian, Mississippi, was originally envisioned as a coal-burning IGCC plant with CO_2 capture. In the original design, the IGCC plant would have combusted a low-grade coal (lignite) to produce hydrogen; however, due to a variety of technical and economic drivers, the originally planned IGCC plant design was abandoned for a simpler, proven technology based on natural-gas instead of coal. The drivers that caused the Kemper project to shift away from the original plan for IGCC+capture included several factors unrelated to the capture technology, specifically: structural problems during construction (*e.g.*, the coal storage dome), supply issues

tied to components for over 900,000 linear feet of pipes (*e.g.*, gaskets, bolts, and pipe hangers), and project management challenges leading to missed deadlines, etc. As a result, costs at the Kemper plant escalated significantly, from the initial projection of $2.88 billion to an excess of $7.5 billion. Finally, concerns arose regarding the likely operational reliability of the facility given the risks associated with a relatively new power-conversion technology: although the operator (Mississippi Power) originally projected that the facility would achieve 80% availability (capacity factor), a subsequent independent assessment (by World Oil Services) forecasted an initial availability of only 30-45% for the first five years with 80% availability occurring after nearly a decade.[2]

3.3 Post-Combustion Capture: Overview of Amine-based Systems

CO_2 capture, in general, includes a number of relatively mature technologies (mostly based on amines), because separation of CO_2 from gas streams is important to several industries, including energy production, cement production, aluminum and steel manufacturing, and natural gas production, as detailed in several reviews (Davison and Thambimuthu, 2009; Rufford et al., 2012; Berstad et al., 2013; Wilcox et al., 2014). Capture from flue gas (*e.g.*, coal-fired power plant) poses some unique challenges over these other industries, particularly with respect to cost, scale, and nature of the flue gas. So, several technologies continue to be investigated for post-combustion capture of CO_2 from a power plant, with a goal of improving the efficiency and costs (see https://netl.doe.gov/coal/carbon-capture). Amine-based systems are the most mature; hence, the Sargent & Lundy pre-feasibility study at the San Juan Generating Station considers an amine-based technology.

Amine scrubbing processes are by far the most widely used form of CO_2 removal technology, with decades of industrial experience (Zaman and Lee, 2013). The process involves contacting the CO_2 rich flue gas with an amine- based solvent in an absorption column. The CO_2 binds reversibly with the amines, removing it from the flue gas; and the CO_2 rich amine solvent is then regenerated to release a pure stream of CO_2. In a stripper column, the solvent regeneration is most often achieved by heating, which is energy intensive. As previously stated, one major benefit of amine-based systems is that they are a mature technology, particularly in applications like natural gas conditioning (Rochelle, 2009; Zaman and Lee, 2013).

Amine-based scrubbing is commercially available for both natural gas and coal-fired power plants, although many absorbents have not been tested beyond the pilot scale for this application. A variety of commercial entities offer amine-based solvents for power-plant applications, including Cansolv Technologies Inc., a subsidiary of Shell Global Solutions International B.V. (the Cansolv Capture System), Fluor Corporation (the Econamine family of CO_2 capture technologies), and Mitsubishi Heavy Industries Engineering Ltd. (KM-CDR Process™ using the KS-1™ amine solvent).

[2] This summary of the experience at the Kemper project is drawn from a report in The Guardian. https://www.theguardian.com/environment/2018/mar/02/clean-coal-america-kemper-power-plant

Amine-based systems applied to post-combustion capture do not involve significant re-engineering of the existing power plant, so their integration risk is low relative to technologies that require significant redesign of the power-plant (*e.g.*, IGCC): the flue gas (or even a slip-stream) can simply be routed to the capture facility once it is operational.

Amine-based systems are being utilized in retrofit applications at two large scale coal-fired power-plants: the Boundary Dam project in Saskatchewan, Canada, and the Petra Nova project in Texas. An amine-based system is also being considered for an emerging project in Saskatchewan (the Shand project; International CCS Knowledge Centre, 2018) and is also used in numerous pilot-scale testing plants around the world including the DOE sponsored National Carbon Capture Center[3]).

SaskPower's Boundary Dam project[4] is an integrated CO_2 capture and storage project, where the CO_2 is used either for enhanced oil recovery (EOR) in the Weyburn-Midale oil field or as part of a demonstration of CO_2 storage in deep saline formations as part of the Aquistore project. It was the first large-scale project to demonstrate post-combustion capture on a commercial coal-fired power plant (Singh and Stéphenne, 2014; Stéphenne, 2014). The repowered 110 – to – 120 megawatt electrical (MWe) power plant can produce about one million metric tons of captured CO_2 per year and uses the Shell Cansolv amine-based solvent to remove CO_2 from the flue gas.

The Petra Nova project retrofitted a 654 MWe coal-fired power plant in Thompsons, Texas, to capture a slipstream from the flue gas (NETL, 2019); up to 240 MW equivalent of the flue gas can be sent to the capture facility. The project utilizes an amine-based technology supplied by MHI developed to capture 90% of the CO_2 in the slipstream, using the proprietary KS-1 solvent that reports low energy requirements, low solvent consumption, and less waste, when compared with a conventional solvent (NETL, 2019). The project was designed to capture up to 1.4 million metric tons of CO_2 per year, using the CO_2 for enhanced oil recovery (CO_2-EOR). Petra Nova has stated publicly that the facility achieves 90% capture of the processed flue gas.[5]

Several considerations are relevant to amine-based systems in the context of evaluating the performance of a CO_2 capture system, including those related to the capture equipment (*e.g.*, the absorber or contactor; the stripper; etc.) and those related to the amines themselves:

- Regeneration and compression energy (the energy requirements to release the CO_2 and to regenerate the amine, along with the energy needed to compress the CO_2 gas to a supercritical state)
- Solvent makeup (*i.e.*, the amount of amine lost or degraded during the process, which then has to be replaced with new amine; amines and amine-breakdown products lost to the capture-facility emissions or recovered as waste)
- Capture efficiency (the fraction of CO_2 that is removed from the flue gas by the amines)

[3] https://www.nationalcarboncapturecenter.com/

[4] https://ccsknowledge.com/bd3-ccs-facility

[5] https://netl.doe.gov/sites/default/files/netl-file/Anthony-Petra-Nova-Pittsburgh-Final.pdf

The first of these impacts both economics and life cycle emissions of CO_2. The second impacts economics, the capture efficiency, and waste effluents. The last impacts economics and the estimation of emission reduction in the flue gas.

Regeneration and compression energy can be sourced from the existing facility and/or from additional power generation sources. The latter option was used at the Petra Nova project with a substantial capital investment; as noted by Jacobson (2019), when natural gas is used as the additional power-generation source for the capture plant, this produces additional CO_2 emissions, essentially lowering the net CO_2 reductions due to the capture facility. In the case of SJGS, however, Sargent & Lundy considered powering the capture facility using a combination of sources from the existing power facility—low-grade steam and auxiliary power derived from the gross power production at the facility. The net result is a lowering of the net power produced for sale by the facility (termed derating), which is discussed below for SJGS in §3.6. This also reduces the capital cost associated with building a separate utility plant to run the capture plant. Energy demands are a straightforward engineering-design factor.

The solvent makeup rate is a factor that is typically determined directly from experience at operational facilities. Hence, Petra Nova and Boundary Dam provide observations that are directly relevant to informing expectations at SJGS. Details on this type of information are not normally publicly available, so our assessment included discussions with experts at MHI relative to the experience at Petra Nova (Thomas et al., personal communication). Although MHI could not provide detailed statistics on the project (which are proprietary to Petra Nova), they noted that the amine performance met or exceeded MHI design expectations. With respect to emissions, MHI noted that the Petra Nova project was designed to meet or exceed stringent regulatory emission requirements relative to amines and their breakdown products. The Petra Nova project included additional scrubbing technology on the absorber emissions, and the project is in compliance with the regulations.

Capture efficiency is discussed in the next section.

3.4 Post-Combustion Capture: Capture Efficiency of Amine-based Systems

In general, capture efficiency for amine-based systems for coal-fired power plants has typically targeted ~90%, meaning that the ≤10% of the original CO_2 is left in the flue gas after it passes through the absorber unit. Capture efficiency can be tuned in response to engineering goals (*e.g.*, in response to considerations on economics, efficiency, etc.); the 90% target originates with a USDOE technology research goal of achieving ≥90% capture from power production (NETL, 2011). As noted in the pre-feasibility study (Sargent & Lundy, 2019), the New Mexico Energy Transition Act requires emissions to be under 1,100 lb CO_2/MWh. This would equate to SJGS capturing at least ~54% of the CO_2 emissions of the plant to be in compliance.

Several public presentations provide datasets on capture efficiency for both Petra Nova and Boundary Dam showing that both facilities have achieved 90% capture (*e.g.*, MHI Group, 2017; Bruce, 2019; Feng, 2019a; Feng, 2019b).

As with regeneration data, extensive capture efficiency data are typically not readily available for long-term performance, so our assessment included discussions with MHI experts relative to the experience at Petra Nova (Thomas et al., personal communication). Although they could not provide detailed statistics on the capture efficiency observed at Petra Nova (which are proprietary to Petra Nova), they noted that the facility is performing as designed and readily capturing 90% of CO_2 from the flue gas that it processes. MHI further noted that data from recent studies suggest a higher capture efficiency (95%) may be an equally efficient target in future projects.

Because capture efficiency data have not been reported publicly, several investigators (*e.g.*, Jacobson, 2019; Schlissel, 2019) have tried to infer efficiency from data that are publicly available. Available data include total CO_2 emissions, and converting these to capture efficiency involves a number of assumptions that can lead to misleading inferences. At the root of the assumptions is the unknown volume of flue gas that has been processed by the capture facility, which depends on several operational variables including:

(i) capacity factor of the power facility (and/or capacity factor of the capture facility), and
(ii) fraction of flue gas that is processed by the capture facility.

In the case of capacity factor, a power plant may be shut down for periods of time due to various factors (technical and/or economic), resulting in no emissions and therefore no captured CO_2; this has affected data on *total volumes* of CO_2 captured for both Petra Nova and Boundary Dam but does not relate to the capture efficiency or the performance of the capture facility relative to its ability to remove CO_2 from the processed flue gas. In other words, the amount of CO_2 captured can be lower than anticipated due to facility shutdowns; this impacts economics associated with the captured CO_2 but it does *not* impact CO_2 emissions from the power plant.

In the case of fraction of flue gas processed, both Petra Nova and Boundary Dam vary the fraction of flue gas processed in response to CO_2 demands tied to CO_2-EOR. When the demand lowers, less flue gas is processed by the capture plant. Thus, the *total volume* of CO_2 captured can be impacted by the demand for CO_2, but this does not relate to the capture efficiency (*i.e.*, to the performance of the capture facility relative to removing CO_2 from the processed flue gas). The fact that CO_2 demand can impact the amount of CO_2 captured is an important takeaway directly relevant to considerations at SJGS as will be discussed below. Choices on the fraction of flue gas that gets processed impact both the economics of the project and the CO_2 emissions from the power plant.

As an example of the challenges associated with inferring capture efficiency, Jacobson (2019) reports an inferred efficiency of 55.4% for the capture facility at the Petra Nova project using an

average CO_2 emissions for 6 months during the early stages of operations,[6] based on an independent assessment of Petra Nova data on CO_2 emissions (Jacobson cites //www.eia.gov/todayinenergy/detail.php?id=33552, which in turn cites //ampd.epa.gov/ampd/). As noted above, MHI has indicated that the observed capture efficiency at Petra Nova has, in fact, been 90%, and Petra Nova has made public presentations giving similar information[7]. Jacobson concludes that his inferred capture efficiency implies that the capture facility falls short of the target of 90% for the efficiency of the capture facility. However, this lower capture efficiency inferred by Jacobson reflects factors associated with the capacity factor of the power generation and the fraction of flue-gas that is processed over time (*not* the performance of the capture facility relative to its ability to remove CO_2 from the processed flue gas). A second factor that may have impacted Jacobson's analysis is that he relied on data from the early stages of the project (the first six months); as with any large-scale facility, early performance (*e.g.*, during the shakedown phase) is unlikely to be indicative of long-term performance, which would be expected to stabilize over longer time.

Another example of the challenges of inferring capture efficiency is reflected in the rebuttal testimony by Schlissel (2019) before the New Mexico Public Regulation Commission. Schlissel (2019) reported a "CO_2 capture rate" of 71% for Petra Nova in the period January 2017 to May 2019 (his Figure 6). Like Jacobson, he implies his calculated capture rate is equivalent to capture efficiency by noting that Petra Nova did not capture 90% of the emissions during that period. He also dismisses the possibility that they could, in fact, have captured 90% of the emissions by referencing the higher capacity factors during that period (his Figure 7), which accounts for factor (i) above. However, his analysis does not account for factor (ii). In other words, the capture facility at Petra Nova could have performed with a capture efficiency of 90% for that fraction of the flue gas that was treated by the capture facility; but operational decisions at Petra Nova did not necessarily send the full fraction of flue gas for treatment. Similarly, Schlissel (2019) also presents data from the Boundary Dam plant in Canada and argued that "Boundary Dam Unit 3 has failed to achieve a 90% carbon capture rate"; Schlissel shows a capture rate of 38–71% (his Figure 11). Schlissel's "capture rate" is *not* the capture efficiency of the amine-based capture plant; rather it reflects the amount of CO_2 captured, which could be less than the total potential due to factors (i) and (ii) above. Indeed, Schlissel does note some contribution from factor (i) in his testimony that Boundary Dam experienced plant downtime; he did not, however, consider the impact of factor (ii).

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[6] In his abstract, Jacobson (2019) reports a capture rate of only 10.8% of the plant's CO_2-equivalent (CO_2e) emissions. Capture rate, however, is <u>not</u> the reported capture efficiency; rather, it represents his assessment of life-cycle emissions spanning from production and transport of the hydrocarbons (coal and gas in this case) through compression of the CO_2. (Jacobson's life-cycle analysis does not account for any emissions during CO_2 transport nor emissions associated with the CO_2-EOR process.)

[7] https://netl.doe.gov/sites/default/files/netl-file/Anthony-Petra-Nova-Pittsburgh-Final.pdf

3.5 Post-Combustion Capture: Non-Amine-based Systems

As noted, non-amine-based systems are generally less mature technologies, so they currently embody higher uncertainty in deployment at large scale. A brief summary is included here for reference to potential future advances to be expected in post-combustion capture technology.

Several technologies are potential targets for advanced capture technologies with performance and/or costs that are improved relative to amines, including: alternative sorbents (*e.g.*, molten metal oxides, ionic liquids, advanced amines, zeolites, etc.), high temperature sorbents (*e.g.*, calcium oxide), nanoscale materials, high temperature membranes, and other novel methods (NRC, 2003).

A variety of novel sorbents are being explored for separation of CO_2 from flue gas, including zeolites, molecular sieves, and activated carbon. These preferentially sorb CO_2 from air-fired combustion products. Once the sorbent saturates with CO_2, it generally is regenerated with a pressure and/or temperature swing. More advanced sorbents remain under development in several research programs.

Membranes are under investigation for both pre- and post-combustion capture. In post-combustion capture, CO_2 is separated from a flue gas by penetrating the membrane faster than other species, specifically N_2. The polymer membrane based post-combustion CO_2 separation systems are currently being evaluated at pilot scale (Chabanon et al., 2013).

Cryogenic technologies separate CO_2 using a thermal swing process to freeze CO_2 as a solid directly on the surface of a heat exchanger. The efficiency of heat transfer degrades with time as solid CO_2 forms on the surface, so capture shifts between parallel heat exchangers, allowing the loaded heat exchangers to regenerate by releasing their solidified CO_2 (*e.g.*, Clodic et al., 2005; Tuinier et al., 2010). The thermal swing can also be accomplished through an expansion process (as opposed to relying on heat exchangers) (*e.g.*, Castrogiovanni et al., 2012). Sustainable Energy Solutions (https://sesinnovation.com/technology/carbon_capture/) has been working on a low-energy cryogenic carbon capture system, which uses a different type of heat exchanger to form the solids, but this is still being tested at scales below pilot (Jensen et al., 2015).

Research efforts on various advanced technologies for post-combustion capture by USDOE can be found at: https://netl.doe.gov/coal/carbon-capture/post-combustion).

Solid sorbents, membranes, and cryogenic processes all require a completely different set of facilities/equipment from those that are installed for amine-based capture.

3.6 Proposed Post-Combustion Capture at the San Juan Generating Station

In its pre-feasibility study, Sargent & Lundy (2019) evaluated the technical feasibility and cost of retrofitting the San Juan Generating Station's Units 1 & 4 with an amine-based carbon capture system. Although no specific technology is detailed at the pre-feasibility stage, Sargent & Lundy base the analysis on information published by two commercially-available systems (MHI and

Cansolv Technologies Inc.), each of which could be implemented as a bolt-on system to the existing SJGS units.

In the following subsections, we comment on specific aspects of the proposed CO_2 capture aspects of the pre-feasibility study.

3.6.1—Capture System Design: The proposed amine capture system follows the same basic configuration as most other amine capture facilities. The flue gas leaves the SJGS and is introduced to a quencher where the flue gas is cooled and additional SO_x is removed to meet the stringent limitations on SO_x concentrations required by the CO_2 capture system. The flue gas then enters an absorber where the CO_2 is absorbed into the amine stream. The resulting CO_2-lean gas is sprayed with water to recover entrained amine and then released. Before entering the stripper column, the CO_2-rich amine stream is pre-heated against the CO_2-lean amine stream that is entering the absorber. The stripper unit uses steam (from the power plant) to heat the CO_2-rich amine, producing a high purity CO_2 stream and a regenerated CO_2-lean amine stream. The high-purity CO_2 stream is cooled to remove moisture and then compressed and sent to the pipeline. This process design is used in various industries for CO_2 capture and the process itself has been demonstrated many times. The ongoing FEED study will presumably provide a greater level of detail on the design of the capture system.

3.6.2—Revised Gross and Net Outputs: Sargent & Lundy calculate a revised gross output for units 1 & 4 after steam extraction for the capture facility of 601 MW (see Table 1 for details).

Table 1: Details of Projected Power from Sargent & Lundy (2019)

	Without Capture		With Capture	
	Unit 1	Unit 4	Unit 1	Unit 4
MW_{gross}	370	544	322	470
MW_{net}	340	507	243	358

3.6.3—Projected Amount of Captured CO_2: Sargent & Lundy report figures for current CO_2 emission rates of units 1 & 4 of 781,916 lb-CO_2/hr and 1,190,946 lb-CO_2/hr, respectively. Assuming that the capture facility operates at full capacity all year and maintains a capture efficiency of 90%, this translates into a total captured CO_2 mass of ~7.1 million metric tons CO_2 per year or ~805 metric tons per hour using a theoretical maximum capacity factor of 100% for the power-generation units (recognizing the actually capacity factor will likely be <100%).

3.6.4—Capture Efficiency: Sargent & Lundy assumed a capture efficiency of 90%, which, as noted above, is a reasonable (if conservative) assumption for the performance of an amine-based capture facility. They note that this would limit CO_2 emissions to 243 lb/MWh_{gross} for unit 1 and 254 lb/MWh_{gross} for unit 4, well below the 1,100 lb/MWh limit required by the Energy Transition Act. (Sargent & Lundy project the weighted average from Units 1 & 4 to be 249 lb/MWh_{gross}.) As also noted above, however, actual capture rates can be limited by CO_2 demand; thus, if CO_2 demand were to drop below the capture rate for CO_2 (*i.e.*, below ~805 metric tons per hour), either the power production would have to be reduced or captured CO_2 would have to be re-emitted. One consideration in refinements to the pre-feasibility study might be to identify options to mitigate potential risks associated with CO_2 demand variability.

It should also be noted that the effective capture rate—which reflects both capture efficiency and amount of flue-gas processed, as detailed above—for a facility at SJGS would only need to be ~54% in order for the facility to comply with the NM Energy Transition Act, so a 90% capture efficiency is more than is needed to meet the emissions goal. In fact, the project could, in principle, meet the goal by processing only 60% of the flue gas at 90% capture or by processing all of the flue gas at 54% efficiency. This is not meant to imply that the facility should or would operate at those rates; rather it provides a measure of the expected effectiveness of a commercial amine-based system relative to the goals in the NM-ETA.

3.6.5—Pipeline: As part of the assessment, Sargent & Lundy assumed the CO_2 would be transported to the Permian Basin via the existing Cortez pipeline. Accessing the Cortez pipeline would require construction of an additional pipeline that would be ~20 miles long. Sargent & Lundy assumed a cost of $40 million for construction costs.

3.6.6—Energy Requirements for Capture Facility: Sargent & Lundy considered all power for the capture facility would be drawn from the generation at units 1 & 4 at SJGS. In other words, they planned no additional power generation unit, such as was done at Petra Nova. The net effect is to derate the net output from units 1 & 4, which Sargent & Lundy estimated to be 601 MW_{net}. This strategy has the advantage of *not* resulting in additional sources of greenhouse gases that would be associated with a new power generation source. Sargent & Lundy consider various strategies to optimize the efficient use of energy at the new facility, including pre-heating of the amine stream (as noted above), use of low-grade steam, use of existing auxiliary power units, etc. The ongoing FEED study—which will develop a more detailed plan for the capture facility—may include additional energy requirements associated with components not detailed at the pre-feasibility stage (such as a solvent purification loop).

3.6.7—Economic Use of Existing Facilities: Sargent & Lundy assessed opportunities to utilize components from the decommissioned units 2 & 3 at SJGS, resulting in potential cost savings. Specifically, the pre-feasibility considered repurposing of an existing cooling tower at unit 3, auxiliary power systems at units 2 & 3, and a circulating water pump at unit 3. These would help to lower capital costs relative to what has been experienced at other projects (*e.g.*, Petra Nova). The Sargent & Lundy assessment considered some costs associated with refurbishing and repurposing. Presumably, future refinements to the pre-feasibility study will improve estimates

of costs associated with the utilization of existing equipment and infrastructure at SJGS—both costs associated with utilization of these decommissioned components as well as an assessment of investments needed to address overall condition of Units 1 & 4 that may have resulted from deferred maintenance decisions by the current owner.

3.6.8—Space: Sargent & Lundy's assessment considered the space needed to accommodate the footprint of the capture facility. This does not appear to be a concern.

3.6.9—Scale Up: Sargent & Lundy's pre-feasibility assessment considered implementing capture using two trains. In other words, the flue gas from the full 914 MW_{gross} would be processed in trains that could accommodate ~457 MW each, which would represent a scale up of ~1.9x from the existing 240 MW train at Petra Nova. MHI has noted that the actual size of individual trains for a specific project would be determined based on engineering and economic considerations; hence, the actual number and size of the trains that might be chosen for SJGS could mean, essentially, no scale-up is needed from Petra Nova's system. In other words, scale up does not appear to be a concern and the size of the required process equipment likely falls within the range of existing operating experience. Presumably, future refinements to the pre-feasibility study will refine the size and number of capture trains.

3.6.10—Water: Sargent & Lundy assessed the water needs of the capture facility and concluded that they can be accommodated using existing water rights associated with SJGS. Nevertheless, as noted in the pre-feasibility assessment, water consumption will increase due to the capture facility. To remain within the current permit, Sargent & Lundy evaluated the treatment of blowdown water and recycle/reuse of water to minimize the net fresh water requirement. With the recycle/reuse of water, Sargent & Lundy expects that the facility will use ~18,000 acre-feet per year out of a permit for 19,000 acre-feet per year (*i.e.*, ~95%). The remaining 1,000 acre-feet per year represents a 17% contingency on the water demands of the capture facility. Presumably future refinements to the pre-feasibility study will refine the plan for water use, resulting in a better estimate of how close a proposed facility would be relative to the existing permit. One strategy for minimizing needs for fresh water might be to explore the future incorporation of a coupled CO_2-storage and water desalination operation local to the SJGS (*e.g.*, as has been explored in the USDOE Brine Extraction Storage Test field projects[8]).

3.7 Regional Emissions: Surface and Satellite Monitoring to Assure GHG/Pollution Reductions

For various reasons, emissions of greenhouse gases in the Four Corners region have been of particular interest, resulting in an extensive network of monitoring stations. In addition to providing background datasets on regional emissions, these monitoring stations could offer an opportunity to verify emission reductions associated with the retrofitting of the SJGS.

Ambient air-quality is continuously monitored at 3 ground stations (Navajo Lake, Bloomfield and San Juan substation) operated by NMED to ensure that criteria pollutant (NO_x, SO_x, CO,

[8] https://www.netl.doe.gov/coal/carbon-storage/storage-infrastructure/fit-for-purpose-best-field-projects

particulates, O_3, and Hg) exceedances are reported to EPA and ameliorative actions taken. The San Juan Generating Station and the Four Corners Generating Station (FCGS) have been the primary sources of the NO_x and SO_x that are transported and react with local sources of hydrocarbons to produce ozone (O_3) downwind in New Mexico and Colorado. This interstate air-pollution problem is a sensitive public issue and is reported and discussed regularly at open meetings at the Clean Air Task Force. Sustained reductions in NO_x and SO_x emissions to improve air quality have been documented by continuous in-stack, surface, and satellite measurements. The SJGS installed low NO_x burners with overfire air and SO_x scrubbers in 2008–2009 that reduced NO_x by 40%. This was followed by the shut-down of two of the four boilers (Units 2 & 3) in 2017 that further reduced emissions. The FCGS also shut down 3 of the 5 boilers in 2013–2014 reducing NO_x emissions by 50%. Reductions in CO_2 emissions also occurred consistent with the capacity reductions associated with shutting down units at both SJGS and FCGS.

As part of the regional monitoring efforts, Los Alamos National Laboratory installed a regional scale green-house gas and pollutant monitoring system next to the SJGS in 2011 at the NMED surface site to verify emissions and their impact on air quality and climate forcing. The system measures solar spectra in the UV-visible and near infrared spectra that respectively provide total column NO_2, SO_2, O_3, CO_2, CH_4, CO, N_2O. Using this station, Lindenmaier et al. (2014) documented that the SJGS had much lower NO_x/CO_2 emissions than the FCGS due to the scrubber upgrades installed at SJGS; further, we demonstrated a regional scale reduction in NO_x using satellite data. This system and/or similar systems could be used to provide independent assessments of reductions in regional emissions associated with a retrofit at SJGS, including verification of reduced emissions of NO_x, SO_x and particulates. In addition, such systems could be expanded to include the ability to monitor amines and associated products as desired.

In summary a regional monitoring system exists in the SJGS region to ensure that emissions of reduces pollutants and greenhouse gases are feasible.

4. Transport/CO_2Use/Storage

As noted above, recent experience with post-combustion capture at power plants (*i.e.*, Boundary Dam and Petra Nova) has demonstrated the importance of CO_2 demand on the net CO_2 that can be captured by a facility. In other words, capturing CO_2 requires reliable options for its disposition. The options for the disposition of captured CO_2 can impact both the economics of the project and the practical constraints of handling a continuous stream of a large volume of material.

In the case of Boundary Dam project[9], the captured CO_2 can be handled via two options: supplied to the Weyburn-Midale oil field[10] for use in CO_2-EOR and/or supplied to the Aquistore project[11] to demonstrate the feasibility of CO_2 storage in a deep saline formation. In the case of the Petra

[9] https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Carbon-Capture-and-Storage/Boundary-Dam-Carbon-Capture-Project

[10] https://ptrc.ca/projects/past-projects/weyburn-midale

[11] https://ptrc.ca/projects/co2-eor-and-storage/aquistore

Nova project[12], the captured CO_2 is shipped via pipeline for CO_2-EOR at the West Ranch oil field[13] in Texas. In CO_2-EOR operations, CO_2 demand can vary in response to the price of oil, resulting in shifting economics associated with specific projects (NETL, 2010; van 't Veld et al., 2013). In CO_2 storage, CO_2 demand is determined by the project economics tied to tax incentives (*e.g.*, 45Q in the United States[14]) and/or research funding (*e.g.*, government grants, company-funded R&D, etc.).

Long-term, there are a number of potential additional options for CO_2 disposition at SJGS, including CO_2 use in a variety of products. Many of these options—as well as options for enhanced hydrocarbon production and/or CO_2 storage—could be developed over time in the Four Corners region.

4.1 Proposed Plan for the Captured CO_2

In its pre-feasibility study, Sargent & Lundy evaluated a strategy for CO_2 use that involves selling captured CO_2 into a pipeline network that supplies Permian Basin CO_2-EOR operations. Sargent & Lundy estimates include construction of a 20-mile pipeline from the capture facility to the existing Cortez pipeline, which extends from the Four Corners region to a central distribution point in Texas from which CO_2 is distributed to a number of CO_2-EOR projects throughout the Permian Basin (LTI, 2018 and https://www.kindermorgan.com/pages/business/co2). The Permian Basin is also served by other pipelines, including the Sheep Mountain pipeline; with a large fraction of the CO_2 in these pipelines is currently drawn from large natural accumulations in reservoirs throughout the Colorado Plateau (Allis et al., 2001).

Several considerations relate to this aspect of the proposed project and pre-feasibility study:

- New pipeline to reach the Cortez pipeline
- Long-term availability of the Cortez pipeline
- Long-term projections for CO_2 demand in the Permian Basin
- Fate/permanency of CO_2 used in CO_2-EOR

4.1.1—New Pipeline: With respect to the access pipeline from the capture facility to the Cortez pipeline, Sargent & Lundy (2019) used a simple estimate of distance and cost, which is reasonable for a pre-feasibility study. They estimated a cost of $40 million to construct the pipeline. Construction of new pipelines between two specific points (*e.g.*, source and trunkline) are relatively straightforward from a technical and costing standpoint, albeit they are impacted by rights of way and other logistical considerations. In a regional scenario within the Four Corners area, optimization strategies may be desirable should multiple sources and sinks be involved (*e.g.*, Middleton and Yaw, 2018).

12 https://www.nrg.com/case-studies/petra-nova.html

13 https://www.usea.org/sites/default/files/event-/Friday-Kennedy_Petra%20Nova%20overview%20for%20CCIF.pdf

14 https://uscode.house.gov/view.xhtml?req=(title:26%20section:45Q%20edition:prelim)

4.1.2—Trunkline Availability: The Cortez pipeline runs ~500 miles from two natural CO_2 reservoirs—McElmo Dome and Doe Canyon, both in Colorado and both operated by Kinder Morgan (LTI, 2018). The Cortez pipeline is owned by Kinder Morgan[15] and has a capacity of 1.5 billion standard cubic feet per day (LTI, 2018) or ~28.4 million metric tons per year. On its website, Kinder Morgan reports that the McElmo and Doe-Canyon domes currently produce 1.2 billion cubic feet per day of CO_2[16], and LTI (2018) reports that their combined production was 1.3 billion cubic feet per day in 2017, translating to 22.7 and 24.6 million metric tons per year, respectively. For comparison, the proposed capture facility at San Juan could produce ~7 million metric tons per year (see above), which could be accommodated fully by the Cortez pipeline, in principal. However, captured CO_2 at SJGS would compete with naturally produced CO_2 from the McElmo and Doe-Canyon domes. LTI (2018) notes that McElmo and Doe-Canyon domes have 286 million metric tons of recoverable CO_2 remaining and that Kinder Morgan has added booster compression at the reservoirs to sustain and extend production. Given the importance of having a reliable option for captured CO_2, additional assessment may be warranted to assess the likelihood of securing access to the Cortez pipeline for the full amount of CO_2 captured. As noted by Sargent & Lundy, one advantage of selling CO_2 into the Cortez pipeline is that the CO_2-EOR market is distributed over a number of operators and operational fields in the Permian Basin, which would help to mitigate fluctuations in CO_2 demand tied to a specific operator/field.

4.1.3—Projected CO_2-EOR in the Permian Basin: CO_2-EOR has been ongoing in the Permian Basin in Southwest Texas and Southeast New Mexico for over 47 years, and although demand has fluctuated in response to oil prices, the CO_2 sales have been relatively stable for the last 10 years at ~1.2 billion standard cubic feet per day (~22.7 million metric tons per year) from the McElmo and Doe-Canyon domes alone (LTI, 2018).

The Permian Basin is the largest CO_2-EOR market in the U.S. and the world. There are currently 81 active CO_2-EOR projects including conventional oil and gas reservoirs as well as residual oil zones. Combined these projects are purchasing ~32 million metric tons of new CO_2 per year. Godec et al. (2017) estimate that Permian Basin has about 59 billion barrels of oil that is technically favorable for CO_2-EOR which will require about 27 billion metric tons of CO_2; for comparison, the SJGS project would capture 0.3 billion metric tons of CO_2 if operated for 50 years at the proposed level. According to DiPietro et al. (2012), the estimated total CO_2 reserves in all U.S. natural CO_2 reservoirs is 2.2 billion metric tons (of which, ~1.5 billion tons is within the proximity of the pipelines supplying the Permian Basin). This significant difference between potential demand and total available natural CO_2 supply could be met by anthropogenic sources of CO_2 like SJGS.

In other words, CO_2 demand for EOR in the Permian is not likely to pose a significant risk for CO_2 disposition associated with capture at SJGS. As noted by Sargent & Lundy, risk associated with future demands in the Permian Basin could be further mitigated through geological storage in reservoirs (either depleted oil & gas reservoirs or deep saline formation). It should be noted,

[15] https://www.kindermorgan.com/pages/business/co2/pipelines/transport_cortez.aspx

[16] https://www.kindermorgan.com/pages/business/co2/supply/supply_doeCanyon.aspx

however, that Sargent & Lundy references "EPA-certified sites in Permian Basin"; to our knowledge, there are currently no EPA-certified CO_2 storage sites in the Permian Basin. There are a number of saline formations in Permian Basin with adequate storage capacity, injectivity, and long-term integrity that could be used for commercial-scale storage sites. But, prior to storage operations, these sites would have to be approved by the appropriate regulatory agencies for long-term CO_2 storage. For example, one component of the approval may tie to obtaining a permit for a geologic-storage injection well (UIC class VI well), which would require regulatory approval beyond that needed for a CO_2-EOR injection well (UIC class II well).

4.1.4—Fate of CO_2 in EOR: CO_2-EOR involves injection of CO_2 into a depleted oil reservoir and production of oil (along with CO_2 and brine). The operation is closed cycle, such that any produced CO_2 is captured and re-injected in the field (NETL, 2010). Over the duration of the project, CO_2 accumulates in the reservoir, replacing the oil and brine that are produced. This accumulated CO_2 may remain stored in subsurface provided the CO_2-EOR sites have storage integrity, which must be adequately characterized and may involve characterization beyond what was initially done for the EOR operation.

There has been some debate on whether CO_2-EOR operations lead to net CO_2 storage. However, it has been well documented that at the end of their lifetime CO_2-EOR operations result in net CO_2 storage. For example, Han et al. (2010) estimate that approximately 55 million metric tons of CO_2 has been permanently stored at the SACROC unit in the Permian Basin during CO_2-EOR operations between 1972–2005. In a broader study, Azzolina et al. (2015) analyzed data from 31 existing CO_2-EOR projects with respect to retention of CO_2. (Retention is a measure of the amount of injected CO_2 that is retained in the reservoir during operations—*i.e.*, the portion that is not cycled out with the produced oil and brine.) Across the 31 case studies, they found retention of ~48% of the injected CO_2 (median value; with P_{10} = 23% and P_{90} = 62%). As noted in the study, the retention value does not mean the remaining CO_2 was released to the atmosphere; rather the CO_2-EOR process captures the recovered CO_2 and recycles it into another injection well.

The United States Environmental Protection Agency (US-EPA) has recently approved multiple applications from CO_2-EOR site operators for tracking amount of CO_2 stored as part of the GHG Reporting Program—Subpart RR[17]. These applications include the Denver & Hobbs Units in the Permian Basin (operated by Occidental Petroleum Company) and the Northern Niagaran Pinnacle Reef Trend (operated by Core Energy). These projects expect net CO_2 storage at the end of CO_2-EOR operation. The predicted total amount of CO_2 stored varies from project to project (Azzolina et al., 2015); net storage for Denver unit is estimated to be ~200 million metric tons and that for the Hobbs unit ~118 million metric tons. While the CO_2-EOR operations result in net CO_2 storage, the net carbon footprint of CO_2-EOR operations is dynamic and dependent on the specifics of CO_2-EOR operations.

Another consideration involves life-cycle greenhouse gas emissions associated with use of CO_2 in an EOR operation. Such an analysis might include emissions associated with the EOR operations

[17] https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide

and even the future emissions associated with the produced hydrocarbon. When anthropogenic CO_2 is used in place of natural sources of CO_2, these downstream emissions effectively cancel when comparing the two scenarios; hence, the replacement of natural CO_2 with anthropogenic CO_2 results in net reductions in emissions of greenhouse gases. In addition, Nunez-Lopez et al. (2019) demonstrate that while CO_2-EOR results in oil production, the sites can be engineered and operated to be net carbon negative. Nevertheless, it can be useful to consider the full life-cycle emissions of an EOR operation. Azzolina et al. (2016) analyzed the life cycle greenhouse gas emissions associated with CO_2-EOR operations, where the gas separation process was based on a Ryan-Holmes process. The emissions—in CO_2 equivalents per barrel of incremental oil produced—were 685 kg CO_2e/bbl, consisting of upstream, gate-to-gate for the EOR operations, and downstream processes (including combustion of the refined product). These emissions are higher than the equivalent for conventional oil production (~500 kg CO_2e/bbl), but when the stored CO_2 is included in the analysis the lifecycle emissions drop to *less* than conventionally produced oil (specifically, down to 435 kg CO_2e/bbl provided CO_2 from avoided emissions is used). When natural CO_2 is used, the higher life cycle emissions would apply. Hence, *if SJGS emissions were used to displace natural CO_2 in the Permian Basin EOR operations, there is potential for a net reduction in life-cycle emissions associated with the oil currently being produced.*

4.2 Potential Future Storage Options in Four Corners Region

In future refinements of the proposed retrofit at SJGS (*e.g.*, perhaps in conjunction with the ongoing FEED study), local options for CO_2 storage might be evaluated as a mechanism to mitigate any potential risks associated with CO_2 demand in the Permian Basin or risks associated with securing access to the Cortez pipeline.

The Four Corners region has several geologic basins that have been exploited by the extractive industries for a variety of purposes.

As mentioned above, one of the largest operations in the region involves the extraction of CO_2 from the McElmoe and Doe Canyon natural CO_2 reservoirs and the transport via pipeline of the CO_2 to other basins for use in CO_2-EOR (Allis et al., 2001). The largest market is currently in the Permian Basin (Texas and New Mexico); although potential markets exist elsewhere, these would generally require construction of additional pipeline infrastructure. There is a longer-term potential to inject CO_2 back into these natural reservoirs that have been depleted, should the economics of CO_2 change.

To date, only one CO_2-EOR operation has taken place in the Four Corners region. The Aneth field in Utah's Paradox Basin has been produced using CO_2-EOR technology since 2007. The Aneth field demonstrates potential for application of CO_2-EOR in the region.

Beyond CO_2-EOR, the basins in the region offer capacity to store CO_2 in geologic reservoirs directly (albeit this would likely require additional regional pipeline network). The potential capacity for geologic storage in the Four Corners region was initially assessed by the Southwest Regional Partnership as part of the USDOE Regional Carbon Sequestration Partnership (RCSP)

initiative (Rodosta et al., 2017)[18]. This assessment estimated a combined CO_2 storage capacity of 181 billion metric tons in the oil & gas fields and deep saline formations in the Four Corners region (McPherson, 2006). The USDOE has recently awarded follow on projects as part of a new round of the RCSP initiative; the Four Corners region will be part of this new, more detailed assessment through the Carbon Utilization and Storage Partnership (CUSP) for the Western USA. The CUSP effort will encompass data collection and synthesis, data analysis, modeling, and scenario development to support more rapid implementation of commercial-scale CCUS in the western US, including the Four Corners region. In future refinements to the pre-feasibility study, results from the original Southwest Regional Partnership effort and the ongoing CUSP effort can be used to inform refinements to the storage options for CO_2 that would be captured at SJGS.

4.3 Mineralization Potential as a Future Storage Option

Longer term options for CO_2 storage also exist in the Four Corners region.

CO_2 mineralization or carbon mineralization is a concept that has been suggested as a route to long-term storage of CO_2, in which magnesium (and to a lesser extent calcium and iron) would be extracted from low-grade silicate rocks and reacted with CO_2 to form solid (and stable) magnesium and calcium carbonates and silica (NASEM, 2019). Both solid products can be safely returned to the originally mined area as part of a reclamation step. Generally, mafic and especially ultramafic rocks are the types of resources amenable to CO_2 mineralization, and several mafic/ultramafic resources with mineralization potential are present in the Four Corners region, including on the Navajo Nation (Goff et al., 2002). Some ultramafic rocks have the additional potential for the production of strategic metals (including platinum-group metals) as a side stream from a CO_2 mineralization process.

4.4 Future Options for CO_2 Utilization

There are several potential options for the captured CO_2 that could be developed in the Four Corners region, including the use of CO_2 to enable hydrogen storage and the production of valuable products from carbon-free energy sources. These provide options that could be considered by the retrofit proposal for SJGS as a reliable pathway for CO_2 demand, potentially resulting in economic development and green-energy jobs in the Four Corners region.

From the standpoint of future green-energy strategies, there is considerable current interest in options for CO_2 capture followed by conversion into useful chemicals/products if the infrastructure allows or one could be introduced in an economically viable and scalable fashion. In such a strategy, CO_2 is captured (from large point sources like SJGS and/or directly from the air) and then it is converted to another chemical form that carries energy derived from a carbon-free energy source (such as solar). As an example, solar energy would be used to split water into hydrogen and oxygen; they hydrogen could then be reacted with the capture CO_2 to produce a

[18] Detailed information on storage potential in the United States can be found in the Carbon Storage Atlas at https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas.

chemical energy carrier such as methanol. In this way, the chemical energy carrier is used to store the intermittent renewable energy in a form that is stable and can be transported readily to a site where it would be used (*e.g.*, used as a chemical feedstock; used for energy production; etc.).

Conversion potentially has the advantage over simple capture by making higher value materials from an undesirable greenhouse gas. Making higher hydrocarbons from methane (CH_4) or from CO_2 either directly or through its conversion into CH_4 still represents a grand science challenge, so significant R&D would be required to take advantage of CH_4 feed streams. USDOE has several ongoing research efforts at various stages of technology readiness.

In terms of established technologies for chemicals productions, an area to consider may be the conversion of CO_2 into methanol (CH_3OH) in a manner akin to the George Olah Renewable Methanol Plant in Iceland. Herein CO_2 is catalytically reduced with hydrogen (H_2), generated from water electrolysis (in this case by using renewable power[19]. The EU funded MefCO2 project[20] similarly uses H_2 electrolytically generated by renewable energy to achieve the same outcome. Methanol, for example, can be used as a hydrogen carrier or in the production of polyester fibers and in anti-freeze formulations. Chemical/electrochemical reduction of CO_2 into a number of other hydrogen carriers (*e.g.* CH_4, formate/formic acid) may also be possibilities.

Another possible method that could be considered for both CO_2 capture and conversion is the use of metal organic frameworks (MOFs). These are a relatively new class of porous materials with unique structural features. They possess high surface areas, chemical tunability and stability, and have been extensively studied with respect to their applicability to capture CO_2 and promote its conversion into other useful molecules (see: Ding et al., 2019, and references therein). Another potentially attractive approach to CO_2 reduction chemistry is to promote it photocatalytically, ideally using solar energy, which is abundant in New Mexico, Texas, and Colorado.

[19] https://www.carbonrecycling.is/george-olah

[20] http://www.mefco2.eu/

Team Biographies

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George Goff (PhD) is an engineer and Acting Group Leader in the Materials Synthesis and Integrated Devices Group (MPA-11). He has 20 years of experience in the area of separations science focusing on problems related to a variety of energy-related topics including nuclear energy and CO_2 capture from flue gas using amine solvents.

John Gordon (PhD) is a scientist with over 30 years of experience in inorganic, organometallic and catalytic chemistries. He is Laboratory Fellow at Los Alamos National Laboratory, a Fellow of the Royal Society of Chemistry (RSC), and was an Invited Fellow of the Japan Society for the Promotion of Science (JSPS).

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Christopher Russell (PhD) is an engineer with 5 years of experience in CO_2 capture systems simulation as part of DOE's program on CCSI2. He is a research engineer in the process modeling and analysis group at Los Alamos.

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