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OFFICE OF FOSSIL ENERGY

Acquisition and Development of Selected Cost Data for Saline Storage and Enhanced Oil Recovery (EOR) Operations

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Disclaimer

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Exhibits

Acronyms and Abbreviations

ARI	Advanced Resources International, Inc.
bbl	Barrel
CapEx	Capital Expenditures
CO_2	Carbon dioxide
DOE	Department of Energy
EIA	Energy Information Administration
EOR	Enhanced oil recovery
ESPA	Energy Sector Planning and Analysis
FE	Fossil energy
H_2S	Hydrogen sulfide
HCPV	Hydrocarbon pore volume
hp	Horsepower
kg/m^3	Kilograms per cubic meter
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
Mcf	1000 cubic feet
MMcf/d	Million cubic feet per day
MPa	Megapascal
NETL	National Energy Technology Laboratory
NGL	Natural gas liquids
O&M	Operation and maintenance
OpEx	Operational Expenditures
psig	Pound per square inch gage
R&D	Research and development
SECARB	Southeast Regional Carbon Sequestration Partnership
tonne	Metric ton (1,000 kg)
UOCI	Upstream Operating Costs Index
U.S.	United States
WAG	Water-Atlernating-Gas
$/bbl	Dollars per barrel
°C	Degrees Celsius
°F	Degrees Fahrenheit

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1 Intro

This memo was prepared by Advanced Resources International (ARI) and provides recommendations for operational cost estimation associated with the continued development of the Fossil Energy (FE)/National Energy Technology Laboratory (NETL) CO_2 Saline Storage Cost Model and the CO_2-Enhanced Oil Recovery (EOR) Storage Cost Model.

Specifically, for CO_2 storage in saline aquifers, the memo presents cost data and recommends cost estimation methods for costs associated with CO_2 injection and surface management, including well equipment, onsite booster compression, and, where water is produced for pressure management in saline aquifers, costs for water production, water injection, and associated surface treatment and wellhead equipment (along with associated piping and facilities). Comparable cost estimation recommendations are provided for CO_2-EOR operations, including the costs associated with oil and water management and production, and CO_2 recycling.

In 2010, Jablonowski and Singh[1] conducted a survey of CO_2-EOR and CO_2 storage project costs. They organized and consolidated information on the sources of these costs, highlighting reasonable approaches for consideration in estimating costs. In general, the authors supported the methods used by ARI's costing algorithms in its CO_2-EOR cost and economics model, documented at the time in most detail publically in the Department of Energy (DOE)/NETL basin studies.[2]

Thus, recommended cost estimation approaches presented in this memo are derived, for the most part, from ARI's costing algorithms, updated consistent with the most recent published work for NETL assessing the potential for CO_2-EOR in the United States (U.S.),[3] and consistently reported in 2008 dollars.

In some cases, these costs are compared to cost estimation approaches documented in CO_2 transport and storage cost estimation guidelines published by DOE/NETL,[4] as well as other sources, where applicable.

Little information exists on cost elements as applied to commercial-scale saline storage operations, since none have yet been implemented in the U.S. at commercial scale. Also, while the concept has been proposed,[5,6] the use of water management and production to enhance CO_2

[1] Jablonowski, C and A. Singh, "A Survey of CO_2-EOR and CO_2 Storage Project Costs," SPE Paper No. 139669-MS presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, New Orleans, Louisiana, USA, 10-12 November 2010

[2] See, for example, Advanced Resources International, *Basin Oriented Studies for Enhanced Oil Recovery: Permian Basin*, U.S. Department of Energy/Office of Fossil Energy, 2006 (http://www.adv-res.com/pdf/Basin%20Oriented%20Strategies%20-%20Permian_Basin.pdf)

[3] U.S. Department of Energy, National Energy Technology Laboratory, *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR)*, DOE/NETL-2011/1504 prepared by Advanced Resources International, June 2011 (http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&Source=Main&PubId=391)

[4] U.S. Department of Energy, National Energy Technology Laboratory, *QGESS: Estimating Carbon Dioxide Transport and Storage Costs*, DOE/NETL-2013/1614, March 2013 (http://www.netl.doe.gov/energy-analyses/quality_guidelines.html)

[5] Akinnikawe, Oyewande, Anish Chaudhary, Oscar Vasquez, Chijioke Enih, and Christine A. Ehlig-Economides, "Increasing CO_2-Storage Efficiency through a CO_2-Brine Displacement Approach," SPE 139467 presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, New Orleans, LA November 10-12, 2010

storage efficiency in saline aquifers has yet to be conducted even at the research and development (R&D) or project demonstration scale.

However, many of the activities associated with CO_2 storage projects are the same as activities associated with oil and gas production and/or water management and disposal operations, both for CO_2-EOR operations, as well as for secondary recovery (waterflooding) operations.[7] As a result, most of the sources of information from which the costs presented here are derived are based on applications in oil and gas production and associated fluid management operations.

Costs can vary considerably based on project design parameters, which include, but are not limited to, injection rate, surface and reservoir pressures, surface and reservoir temperatures, and CO_2 composition.[8] Moreover, the quality of a cost estimate is most dependent on the quality of the data upon which it is based, which was perhaps the primary conclusion of Jablonowski and Singh.[9] Moreover, every project will have idiosyncrasies that complicate cost normalization and estimation for "generic" or "representative" projects such as those considered in the FE/NETL CO_2 Saline Storage and the CO_2-EOR Storage Cost Models.

Recognizing that the FE/NETL CO_2 Saline Storage Cost and the CO_2-EOR Storage Cost Models are screening level models, and that there is considerable uncertainty associated with both the input data and engineering assumptions used by these models, the objective here was to incorporate relatively simple cost estimation approaches. These should be replaced by more site-specific, engineering-based approaches, calculations, and cost estimates if and when more detailed site characterization, project design, engineering costing, and project economic evaluations are performed.

In the discussion below, what we have attempted to do is first present the cost estimation approaches associated with "state-of-the-art" CO_2-EOR operations, which involve fluid production, oil/water separation, and CO_2 injection. The process flow diagram for this is illustrated in Exhibit 1-1. CO_2-EOR project costs are well established and vetted. At the end of this memo, the additional costs associated with the application of "next generation" CO_2-EOR operations are presented.

Cost estimation approaches for CO_2 storage in saline aquifers are presented in terms of documenting which cost elements (considered for CO_2-EOR) should be removed or altered in the CO_2 injection/storage-only context.

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[6] Buscheck, T.A., Y. Sun, M. Chen, Yue Hao, T.J. Wolery, S.J. Friedmann, and R.D. Aines, "Active CO_2 Reservoir Management for CO_2 Capture, Utilization, and Storage: An Approach to Improve CO_2 Storage Capacity and Reduce Risk," CMTC 151746 presented at the Carbon Management Technology Conference, Orlando, FL, February 7-9, 2012

[7] Veil, J.A., C.B. Harto, and A. T. McNemar, "Management of Water Extracted from Carbon Sequestration Projects: Parallels to Produced Water Management," SPE Paper No. 140994 presented at the SPE Americas E&P Health, Safety, Security, and Environmental Conference, Houston, Texas, March 21-23, March 2011

[8] McKaskle, Ray, "MGSC IBDP: Optimization of Surface Facilities," Presentation at the Midwest Carbon Sequestration Science Conference, Champaign, IL, September 18, 2012

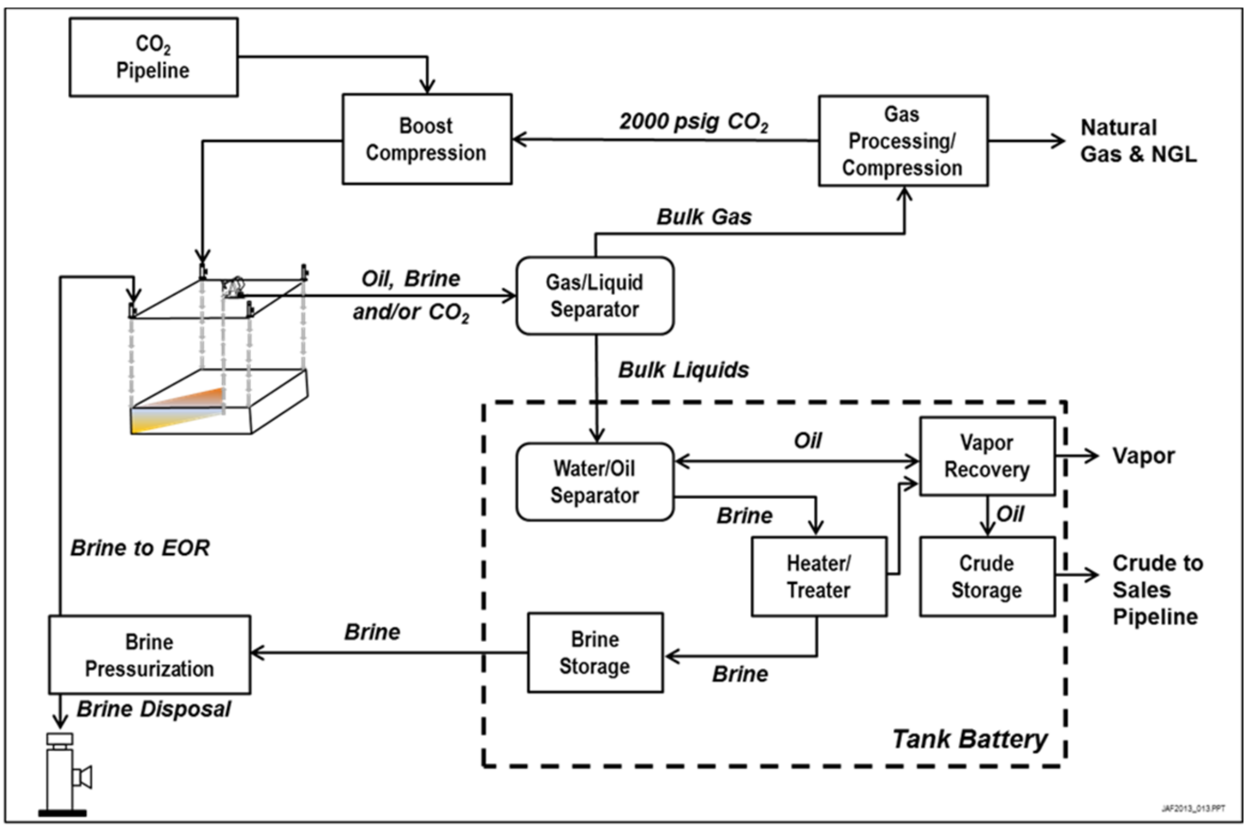
[9] Jablonowski, C and A. Singh, "A Survey of CO_2-EOR and CO_2 Storage Project Costs," SPE Paper No. 139669-MS presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, New Orleans, Louisiana, USA, 10-12 November 2010

For CO_2 injection in saline aquifers, two scenarios are considered: the first involves costs associated with CO_2 injection into a saline aquifer without pressure management (via the production of formation water). In this case, almost all of the elements in Exhibit 1-1 are removed, except for equipment associated with the injection wells, for compression, and for the manifolds and distribution lines associated with CO_2 logistics on the surface.

The second scenario assumes CO_2 injection with water production for pressure management. In this case, the process flow diagram is essentially the same as for CO_2-EOR, except that oil is not one of the byproducts of fluid separation. For this scenario, however, we only assume the water produced is reinjected for disposal in another formation. No other uses for the water produced are considered. Cost estimates for alternative beneficial uses for the produced water have been developed and reported separately.

In this study, all capital costs are presented on a cost per well basis, and all operation and maintenance (O&M) costs are presented on either a cost per well or cost per unit of production basis. All reported costs are installed costs.

Exhibit 1-1 Process Flow Diagram for CO_2-EOR Operations



Source: ARI

2 Well Costs Considerations

Next to the cost of acquiring CO_2, well costs are the single largest cost element associated with CO_2-EOR projects. Although not explicitly a focus for this work, some discussion associated with well cost considerations is warranted. If fluids are produced as part of CO_2 injection operations (either as part of a CO_2-EOR project or when water is produced to manage reservoir pressure in a CO_2 storage project), then costs associated with drilling water production wells will need to be considered. Since the water produced from the CO_2 storage reservoir is reinjected into another formation, then the costs associated with those water injection wells will also need to be considered.

2.1 Well Requirements

Well costs primarily depend on how many wells are required to produce and re-inject a specific volume of CO_2, and in the case of managing reservoir pressure by producing water, the wells required to produce and re-inject this water. For projects undertaken in depleted oil and gas fields and for CO_2-EOR, some existing wells may be able to be reworked or converted from a producer to an injector.

For CO_2 injection for storage, the FE/NETL CO_2 Saline Storage Cost Model estimates maximum CO_2 injection rates per well. Based on these estimates, and the total amount of CO_2 requiring storage and the number of CO_2 injection wells required is estimated.

A similar approach is used in the CO_2-EOR Storage Cost Model, though in this case, estimates are made for new production and CO_2 injection wells required, as well as the existing production wells converted into CO_2 injection wells and the existing waterflood production and/or injection wells reworked for CO_2-EOR deployment.

For water production/injection, assuming a "typical" well with 9.5 inch surface casing, 5.5 inch production casing, and 3.5 inch tubing (this is similar to the injection wells drilled for the Southeast Regional Carbon Sequestration Partnership [SECARB] CO_2 injection tests), water production/injection rates of about 5,000 barrels per day per well could safely be assumed. Given the screening level nature of the FE/NETL CO_2 Saline Storage Cost Model, there is no need for more detailed, reservoir-specific rate calculations at this level of analysis. Defining the true impacts of a specific reservoir's characteristics on water production and/or injection (based on reservoir engineering principles) requires use of more detailed reservoir simulation and input data than that available to the FE/NETL CO_2 Saline Storage Cost Model.[10]

2.2 Well Costs

To avoid CO_2 entrained in the water produced in association with a potential CO_2 storage operation, water production wells should be place beyond the plume boundary. This will avoid the potential need for a Class VI permit for a water disposal well. A water production well can be constructed under the same standards as CO_2 injection well but without the need for corrosion protection. Thus, drilling and completion costs associated with water production wells can be comparable to those assumed in the model for CO_2 injection wells. Well costs in the FE/NETL CO_2 Saline Storage Cost Model are derived from algorithms based on data in the 2006 API-JAS.

If the water produced from the CO_2 storage reservoir is re-injected into another formation, then the costs associated with those water injection wells will also need to be considered. Again, these

[10] Bennion, D. B., F. B. Thomas, D. Imer, T. Ma, and B. Schulmeister, "Water Quality Considerations Resulting in the Impaired Injectivity of Water Injection and Disposal Wells," *Journal of Canadian Petroleum Technology*, Volume 40, Number 6 , June 2001

water injection wells can be constructed to similar standards as the CO_2 injection wells. Thus, drilling and completion costs associated with water injection wells can be comparable to those assumed in the model for CO_2 injection wells.

To minimize CO_2 in the produced water, the water production wells could be placed outside of the plume to assure CO_2-free water. If CO_2 is mixed with water then subsequent injection would require a Class VI permit.

According the 2008 Joint Association Survey on Drilling Costs[11] for a well handling water with no entrained CO_2, a 7,500 foot well with drilling and completion costs of $5,000,000 per well, producing over a 20-year well life at a rate of 5,000 barrels/day/well, would result in unit costs per barrel produced of $0.14/bbl of water.

3 Surface Facility Costs for On-Site CO_2 Injection and Management

3.1 CO_2 Recycle Plant Capital Cost

Operation of a CO_2-EOR project requires a recycling plant to capture and reinject the produced CO_2. Although different CO_2 flood designs require different specifications for a CO_2 plant, they all generally require some or all of the following: gas/liquid separation, water/oil separation, dehydration, CO_2/hydrocarbon gas separation (including possibly H_2S removal), and CO_2 compression for reinjection. For purposes of this assessment, these are all included in the estimated CO_2 recycle plant cost estimate. This estimate does not include the costs associated with natural gas liquids (NGL) recovery.

No attempt was made here to itemize separately the individual components represented in Exhibit 1-1 as they relate to CO_2 recycling. In general, the input data for the CO_2-EOR Storage Cost Model will not provide sufficient information to determine the extent that H_2S removal or NGL removal may be required. Moreover, in some cases, additional processing may occur downstream of the CO_2-EOR field. And H_2S does not necessarily inhibit miscible flooding if reinjected with the CO_2, so long as health and safety considerations are taken into account.

The size of the recycle plant is based on peak CO_2 production and recycling requirements and the costs are based on the size of the plant. If the peak rate is less than 30 million cubic feet per day (MMcfd) or 0.579 million tonnes per year, then

Capital cost (in 1,000 $) = 1,200 * Peak Rate (in MMcfd of CO_2 throughput)

If peak rate is greater than 30 MMcfd, then

Capital cost (in 1,000 $) = 36,000 + (Peak Rate – 30) * 750

Again, the peak rate is expressed in MMcfd of CO_2 throughput. It should be noted that “cf” refers to cubic feet at standard temperature (60 °F) and pressure (14.696 psig).

Approximately half of the total costs for the recycle plant correspond to the costs of compression.

The full cost of the plant can be assumed to be incurred at the start of the project.

[11] American Petroleum Institute, *2008 Joint Association Survey on Drilling Costs*, April 2010

3.2 NGL Recovery Facilities Capital Cost

If NGL recovery also needs to be considered, additional capital costs can be assumed based on Tannehill,[12] as follows:

For throughput rates less than 20 MMcfd or 0.386 million tonnes per year:

Capital cost = $ 350,000 * Peak Rate (in MMcfd of CO_2 throughput).

For throughput rates greater than 20 MMcfd:

Capital cost = $7,000,000 + 25,000 * (Peak Rate – 20) (in MMcfd of CO_2 throughput).

These equations assume a straight refrigeration process, and include the facilities to produce a single product, with no fractionation and limited storage. Glycol injection with regeneration of the glycol is included. Pre-compression or treating of the inlet gas is not included.

3.3 CO_2 Recycle O&M Costs

The O&M costs of CO_2 recycling (in $ per Mcf of CO_2 processed) are indexed to energy costs and set at 1 percent of the oil price per barrel (e.g., $0.85 per Mcf @ an $85/bbl oil price). This is because the largest component of CO_2 recycling O&M costs is associated with the energy for compression of the CO_2 for reinjection, and this energy is often produced on-site.

The capital and O&M costs associated with the CO_2 recycle plant would not be incurred for a CO_2 storage project in a saline aquifer, unless it is assumed, in the case where water is produced to help manage reservoir pressure, that some CO_2 is produced in association with the produced water. To minimize CO_2 in the produced water, the water production wells could be placed outside of the plume to assure CO_2-free water. If CO_2 is mixed with water then subsequent injection would require a Class VI permit.

3.4 CO_2 Distribution Supply and Distribution System Costs

The CO_2 supply and distribution system for CO_2-EOR and CO_2 storage with produced water management is similar to the gathering systems used for natural gas. The costs consist of two components – a fixed component, and a variable component that is a function of distance and volume injected. The fixed component is $200,000. The fixed component represents all manifolds and distribution lines on the site, from the production wells to the recycle plant, and from the recycle plant to the injection wells. For a CO_2-EOR project operation, the distribution pipeline network must also be able to accept water and have controls that allow either water or CO_2 to be delivered to the injection wells.

The variable component consists of a "feeder" pipeline that brings CO_2 from a larger, "main" CO_2 pipeline to the CO_2-EOR site or CO_2 storage site. This "feeder" pipeline will have a large pipe (maybe more than one) exiting the boost compressor feeding into a header or manifold

[12] Tannehill, C.C., "Budget Estimate Capital Cost Curves for Gas Conditioning and Processing – Updated", Proceedings of the 88th Annual GPA Meeting, San Antonio, Texas, USA, March 2009

system that diverts the CO_2 into a number of smaller diameter pipes that carry the CO_2 to the injection wells.

The cost of this feeder pipeline accounts for both the volume being injected and the distance from the CO_2 source or CO_2 "hub" (transfer point) to the oil field. The variable cost component (C_D) accounts for increasing piping diameters associated with increasing CO_2 injection requirements, specifically:

- $360,000 per mile for 4-inch pipe (CO_2 rate less than 15 MMcf/d or 0.29 million tonnes per year)
- $540,000 per mile for 6-inch pipe (CO_2 rate of 15 to 35 MMcf/d or 0.29 to 0.676 million tonnes per year)
- $720,000 per mile for 8-inch pipe (CO_2 rate of 35 to 60 MMcf/d or 0.676 to 1.16 million tonnes per year)
- $900,000 per mile for pipe greater than 8 inches in diameter (CO_2 rate greater than 60 MMcf/d or 1.16 million tonnes per year).

Therefore, the overall equation for representing the costs of the CO_2 distribution system is as follows:

<u>CO_2 Distribution Supply and Distribution System Cost</u> =

$200,000 + C_D*Distance (in miles)

Where: C_D is the cost per mile of the necessary pipe diameter (based on the CO_2 injection rate)

These costs would be incurred for both CO_2-EOR projects and CO_2 storage in saline aquifers.

For comparison, CO_2 transport and storage cost estimation guidelines published by DOE/NETL also have some cost equations for pipeline costs, as shown in Table 2 in that document.[13] In addition, a cost equation was developed in Cook (Table 2 in that document).[14] The cost equations presented here give cost estimates comparable to those in the NETL guidelines and in Cook.

4 Onsite CO_2 Booster Compression

Because of the high injection pressures required for CO_2 injection and storage, boost compression may be required for both new CO_2 sources (unless those sources are already delivered at injection pressure, which is generally the case today) and recycled CO_2 being produced from the reservoir. Costs associated with compressing CO_2 for CO_2-EOR are included in the recycling plant costs presented above. In general, it can be assumed in the CO_2 Saline Storage Cost Model that the CO_2 is delivered at injection pressure.

[13] U.S. Department of Energy, National Energy Technology Laboratory, *QGESS: Estimating Carbon Dioxide Transport and Storage Costs*, DOE/NETL-2013/1614, March 2013 (http://www.netl.doe.gov/energy-analyses/quality_guidelines.html)

[14] Benjamin R. Cook, *Wyoming's Miscible CO_2 Enhanced Oil Recovery Potential in Main Pay Zones: An Economic Scoping Study*, University of Wyoming, Enhanced Oil Recovery Institute, November 2012

However, it may be necessary to assess additional compression costs if the CO_2 is not assumed to be delivered at injection pressure. CO_2 compression power requirements depend on the differential between the pressure of the CO_2 delivered to the site (recall that compression costs are already included in cases where the source of the CO_2 is the recycle plant) and the required field injection pressure. This range is directly affected by the pressure of the source (or recycled) CO_2 and the characteristics of the reservoir that dictate the injection pressure (porosity, permeability, thickness, etc.). In general, the higher the pressure of the source CO_2, the lower the compression energy requirements.

4.1 Compressor Capital Costs

To calculate the pumping power requirement (W_p, in horsepower (hp)) for boosting the CO_2 pressure from the source (P_{source}) to the required injection pressure (P_{inj}) (in MPa), the following equation can be assumed:[15]

$$W_p = 1.341*((1000*10)/(36*24))*((m*(P_{inj}-P_{source}))/(\rho*\eta_p))$$

Where m is the CO_2 mass flow rate (in tonnes/day), and the following values can be assumed:

$\rho = 630$ kg/m^3

$\eta_p = 0.75$

1.341 = hp/kW

1,000 = kilograms per tonne

24 = hours per day

10 = bar/MPa

36 = m^3*bar/hour per kW

For purposes of this assessment, a capital cost of $2,000 per hp can be assumed, based on the assessment of Jablonowski and Singh.[16]

4.2 Energy Costs

The annual energy required for compression is estimated by multiplying W_p by the period of time over which the power is used. For example, if the compressors run 60 percent of the time over the course of the year, W_p would be multiplied by 5,256 (0.60 * 365 days/year * 24 hours/day) to get to kWh.

The costs of power for compression can be calculated assuming the U.S. average cost of purchased electricity multiplied by the power requirements in kWh. The average cost of

[15] McCollum, D., Ogden, J., *Techno-Economic Models for Carbon Dioxide Compression, Transport and Storage*. Institute of Transportation Studies, University of California, Davis, October 2006 (http://publications.its.ucdavis.edu/publication_detail.php?id=1047)

[16] Jablonowski, C and A. Singh, "A Survey of CO_2-EOR and CO_2 Storage Project Costs," SPE Paper No. 139669-MS presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, New Orleans, Louisiana, USA, 10-12 November 2010

electricity per kWh was \$0.1036/kWh for the commercial sector and \$0.0683/kWh for the industrial sector in 2008.[17]

5 Surface Facility Costs for Fluid Management

5.1 Lease Equipment for Fluid Management

The costs for surface equipment for fluid production from new wells are expected to be similar whether applied to a CO_2-EOR operation or to a saline aquifer CO_2 storage project from which water is produced for pressure management. Lease equipment costs for fluid production can be based on the Energy Information Administration's (EIA) annual Oil and Gas Lease Equipment and Operating Costs report (the latest for 1994 through 2009).[18] This survey provides estimated lease equipment costs for 10 wells producing with artificial lift, from depths ranging from 2,000 to 8,000 feet, into a central tank battery.

Advanced Resources has developed an equation which contains a fixed cost constant for common cost items, such as free water knock-out, water disposal and electrification, and a variable cost component to capture depth-related costs, such as for pumping equipment. The equation is:

$$\text{Production Well Equipping Costs} = c_0 + c_1 D$$

Where: c_o = \$23,000 (fixed)

c_1 = \$25 per foot

D is well depth

A 7,500 foot well would have production equipment costs of \$210,500 per well. If the equipment cost of this well is amortized over 10 years with a consistent production rate of 5,000 barrels/day/well, it would result in unit costs per barrel produced of \$0.01/bbl of water.

These costs would not be considered if no fluids are produced in association with the CO_2 injection/storage project.

5.2 Lease Equipment Costs for New Injection Wells

In addition, costs are also associated with injection equipment, which includes equipment for simple treatment of the produced water to minimize impacts of fouling of injection wells.

The costs associated with injection equipment are also derived from the EIA Oil and Gas Lease Equipment and Operating Costs report. The costs for equipping new injection wells include distribution lines, a header, and electrical service, as well as a water pumping system. Table 2 of the Excel spreadsheet provided with the report tabulates costs for oil field lease equipment for secondary recovery (waterflood) operations in West Texas, documenting separately injection

[17] Energy Information Administration, *Electric Power Monthly*, March 22, 2013 (data for 2008)

[18] Energy Information Administration, *Oil and Gas Lease Equipment and Operating Costs 1994 Through 2009*, September 28, 2010 along with associated Excel spreadsheet provided (http://www.eia.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html)

equipment, production equipment, and injection wells. Costs for water storage tanks, injection plant, filtering systems, injection lines, and drilling water supply wells and water injection wells are included. In the EIA report, these costs assume equipment designed to handle 350 barrels of liquid per day per injection well.

These costs only include simple treatment for reinjection; they do not consider costs for water treatment for reuse.

Equipment costs include a fixed cost component and a depth-related cost component, which varies based on surface pressure requirements. The equation is:

$$\text{Injection Well Equipping Costs} = c_0 + c_1 D$$

Where: c_0 = \$95,000 (fixed)

c_1 = \$16 per foot

D is well depth, in feet

We assume that these costs are applicable to all regions.

A 7,500 foot well would have injection equipment costs of \$215,000 per well. As with the producing well, if the equipment cost for this well is amortized over 10 years with a consistent rate of 5,000 barrels/day/well injected, it would result in unit costs per barrel produced of \$0.01/bbl of water.

Note that these costs are assumed to be the same regardless of rate. In other words, even though the costs in EIA Oil and Gas Lease Equipment and Operating Costs report assume equipment designed to handle 350 barrels of liquid per day per injection well, the assumption here is that these same costs apply to larger volume injection operations. We have no basis, at this stage of model development, to further refine these cost estimates. (Moreover, these cost estimates are consistent with the current costing algorithms in DOE/NETL's CO_2-EOR cost and economics model).

This equation gives cost estimates that are comparable to the injection equipment cost estimation guidelines published by DOE/NETL, as shown in Table 3 in that document.[19]

Again, these costs would not be considered if no fluids are produced in association with the CO_2 injection/storage project. In other words, the costs for the distribution pipeline network apply to CO_2/water injection wells at CO_2-EOR sites and water disposal wells at CO_2-EOR and saline storage sites. These costs are not applicable to distribution pipeline network at saline storage sites

5.3 Annual O&M Costs, Including Periodic Well Workovers

The costs associated with secondary recovery (waterflooding) operations for West Texas are also reported in EIA's annual Oil and Gas Lease Equipment and Operating Costs report.[20] Table 4 of

[19] U.S. Department of Energy, National Energy Technology Laboratory, *QGESS: Estimating Carbon Dioxide Transport and Storage Costs*, DOE/NETL-2013/1614, March 2013 (http://www.netl.doe.gov/energy-analyses/quality_guidelines.html)

the Excel spreadsheet provided with the report tabulates O&M costs for secondary recovery operations in West Texas, documenting separately normal daily operations, surface repairs, and subsurface repairs, assuming equipment designed to handle 350 barrels of liquid per day per producing well. Operational costs for secondary oil production are indicated for the increased liquid lift of 250 barrels of liquid per day per producing well and for the water injection system.

To account for the O&M cost differences between waterflooding and CO_2-EOR, two adjustments are made to the EIA's reported O&M costs for secondary recovery. Workover costs, reported as surface and subsurface maintenance, are doubled to reflect the need for more frequent remedial well work in CO_2-EOR projects. Liquid lifting costs are subtracted from annual waterflood O&M costs to allow for the more rigorous accounting of liquid lifting volumes and costs for CO_2-EOR. (Liquid lifting costs for CO_2-EOR are discussed in Section 5.4.)

It is assumed here that these operating costs for secondary recovery operations for oil production should be comparable to those associated with injection into saline aquifers, based on the recommendation of Jablonowski and Singh.[21] *Therefore, for purposes here, we also assume that the operating costs for CO_2 injection wells at saline storage sites should be comparable to the operating costs for CO_2 injection wells at CO_2-EOR sites*

The equation used for estimating these costs is as follows:

$$\text{Well O\&M Costs} = b_0 + b_1 D$$

Where: D is well depth, in feet

In EIA's annual Oil and Gas Lease Equipment and Operating Costs report,[22] annual O&M costs for secondary recovery are only reported for West Texas. For purposes here, we assume that costs for secondary recovery vary by region comparably as those for primary recovery. Based on that assumption, the estimated costs for annual O&M are based on region-specific values for b_0 and b_1, as summarized below:

Region	b_0	b_1
West Texas	34,000	4.00
California	42,160	4.96
Rocky Mountains	38,080	4.48
South Texas	31,280	3.68

[20] Energy Information Administration, *Oil and Gas Lease Equipment and Operating Costs 1994 Through 2009*, September 28, 2010 along with associated Excel spreadsheet provided (http://www.eia.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html)

[21] Jablonowski, C and A. Singh, "A Survey of CO_2-EOR and CO_2 Storage Project Costs," SPE Paper No. 139669-MS presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, New Orleans, Louisiana, USA, 10-12 November 2010

[22] Energy Information Administration, *Oil and Gas Lease Equipment and Operating Costs 1994 Through 2009*, September 28, 2010 along with associated Excel spreadsheet provided (http://www.eia.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html)

Louisiana	37,400	4.40
Oklahoma	42,840	5.04

This equation gives cost estimates that are comparable to, though somewhat lower than, those associated with the injection O&M cost estimation guidelines published by DOE/NETL, as shown in Table 3 in that document.[23]

A 7,500 foot well would have injection O&M costs of $64,000 per well per year. If this well produces at a rate of 5,000 barrels/day/well, it would result in unit costs per barrel produced of $0.04/bbl of water.

5.4 Fluid Lifting Costs

Energy (power) is required to lift fluids up a wellbore, manage it on the surface, and inject it back down hole (either back into the producing reservoir or into another disposal formation). The ARI CO_2-EOR economics model currently assumes that liquid (oil and water) lifting costs are calculated on total liquid production and estimated at $0.25 per barrel. This cost includes liquid lifting and transportation.

Looking just at lifting costs, one must account for the fact that fluid pumps do not operate at 100 percent efficiency. A properly designed and adjusted pumping system will operate at about 70 percent efficiency; however, efficiencies can be as low as 40percent. Based on a 1999 study by Conlon, et al., depending on type of pump, average water pump efficiencies can range from 44percent to 62 percent.[24]

The Tulare (California) Cooperative Extension Surface published information on the energy requirements to lift one acre-foot of water one foot at different pumping plant efficiencies, as shown below.[25]

[23] U.S. Department of Energy, National Energy Technology Laboratory, *QGESS: Estimating Carbon Dioxide Transport and Storage Costs*, DOE/NETL-2013/1614, March 2013 (http://www.netl.doe.gov/energy-analyses/quality_guidelines.html)

[24] Conlon, Thomas, Glen Weisbrod, and Shahana Samiullah, "We've Been Testing Water Pumps For Years – Has Their Efficiency Changed?" Proceedings of the 1999 ACEEE Summer Study of Energy Efficiency In Industry, April 1999 (http://www.edrgroup.com/pdf/pumptest.pdf)

[25] Peacock, Bill, "Energy and Cost Required to Lift or Pressurize Water," Tulare County Farm Advisor, University of California, Tulare County Cooperative Extension, Pub. IG6-96, 1996 (http://cetulare.ucanr.edu/files/82040.pdf)

Overall Plant Efficiency (%)	kwh/acre-foot/foot	kwh/barrel/foot
100	1.02	1.315E-04
75	1.37	1.766E-04
70	1.46	1.882E-04
65	1.58	2.037E-04
60	1.71	2.204E-04
55	1.86	2.398E-04
50	2.05	2.642E-04
45	2.28	2.939E-04
40	2.56	3.300E-04

Thus the energy required to lift water up the wellbore can be estimated by multiplying the energy to lift one acre-foot of water one foot by the depth of the well. That amount of energy can be then multiplied by the cost of electricity to get the energy costs for lifting water. For example, assuming a 55 percent efficient pump, the energy required to lift water up a 7,500 foot well would be:

(2.398×10^{-4}) kwh/barrel/foot x 7,500 feet = 1.7985 kwh/barrel

Assuming the U.S. average cost of purchased electricity for the industrial sector in 2008 of $0.1036/kWh, gives lifting costs of:

1.7985 kwh/barrel x $0.1036/kWh = $0.19/barrel

Given this, the lifting costs assumed in the ARI CO_2-EOR economics model of $0.25 per barrel, which includes liquid lifting and transportation seems reasonable.

These costs would not be considered if no fluids are produced in association with the CO_2 injection/storage project.

5.5 Injection Energy Costs

Electricity is also required for injecting water into injection wells. Water injection electricity requirements are dependent on the injection pressure and volume of fluid being injected.[26] Injection energy requirements can be calculated by the equation:

$$BHP = (Q*(P_d - P_s))/(1714*ME)$$

Where BHP is the horsepower of the pump, Q is the amount of fluid compressed in gallons/minute, P_d is the discharge pressure, P_s is the initial pressure, and ME is the mechanical efficiency of the pump.

[26] Horsepower can be converted into kilowatts by multiplying by 0.747. Source: http://www.pumpcalcs.com/calculators/view/81/

Assuming 5,000 barrels per day per well (146 gallons per minute), a 55 percent efficient pump, and a pressure drop of 500 psia, the power requirements of an injection pump would be about 77 hp, or about 58 kW.

Water injection electricity requirements per barrel of water can be calculated by:

(58 kw) x (24 hours/day)/((5,000 barrels per day)*0.55) = 0.5 kWh/bbl

Assuming the U.S. average cost of purchased electricity for the industrial sector in 2008 of $0.1036/kWh, gives lifting costs of:

0.5 kwh/barrel x $0.1036/kWh = $0.05/barrel.

6 Summary of Water Management Costs

A June 2000 report in *Oilfield Review*[27] featured a table showing typical estimated water handling costs per barrel associated with oil and gas production, reporting costs for lifting, separation, de-oiling, filtering, pumping, and injection for different fluid production rates. Costs were reported separately for CapEx and OpEx, utilities, and chemicals. With costs updated from 2000 to 2008 (based on the IHS CERA Upstream Operating Costs Index [UOCI]),[28] this table is summarized in Exhibit 6-1.

[27] Bailey, Bill, Mike Crabtree, Jeb Tyrie, Jon Elphick, Fikri Kuchuk, Christian Romero, and Leo Roodhart, "Water Control," *Oilfield Review*, June 2000

[28] http://www.ihs.com/info/cera/ihsindexes/index.aspx

Exhibit 6-1 Water Management Costs from Oilfield Review Article

		Produced Water Volume (bbl/day)					
Category		**20,000**	**50,000**	**100,000**	**200,000**	**Average**	**% of Total**
Lifting	CapEx/OpEx	$0.076	$0.076	$0.076	$0.076	$0.076	
	Utilities	$0.101	$0.109	$0.109	$0.109	$0.107	
	Chemicals	$0.000	$0.000	$0.000	$0.000	$0.000	
		$0.177	**$0.185**	**$0.185**	**$0.185**	**$0.183**	**18%**
Separation	CapEx/OpEx	$0.150	$0.079	$0.060	$0.052	$0.085	
	Utilities	$0.004	$0.006	$0.006	$0.006	$0.006	
	Chemicals	$0.058	$0.058	$0.058	$0.058	$0.058	
		$0.212	**$0.144**	**$0.125**	**$0.116**	**$0.149**	**14%**
De-oiling	CapEx/OpEx	$0.253	$0.126	$0.096	$0.079	$0.138	
	Utilities	$0.081	$0.083	$0.083	$0.083	$0.082	
	Chemicals	$0.000	$0.000	$0.000	$0.000	$0.000	
		$0.334	**$0.208**	**$0.179**	**$0.162**	**$0.221**	**21%**
Filtering	CapEx/OpEx	$0.253	$0.117	$0.081	$0.052	$0.126	
	Utilities	$0.024	$0.020	$0.020	$0.020	$0.021	
	Chemicals	$0.000	$0.000	$0.000	$0.000	$0.000	
		$0.277	**$0.137**	**$0.101**	**$0.072**	**$0.147**	**14%**
Pumping	CapEx/OpEx	$0.356	$0.210	$0.157	$0.136	$0.215	
	Utilities	$0.067	$0.069	$0.069	$0.069	$0.068	
	Chemicals	$0.000	$0.000	$0.000	$0.000	$0.000	
		$0.423	**$0.278**	**$0.225**	**$0.204**	**$0.283**	**27%**
Injection	CapEx/OpEx	$0.052	$0.052	$0.052	$0.052	$0.052	
	Utilities	$0.000	$0.000	$0.000	$0.000	$0.000	
	Chemicals	$0.000	$0.000	$0.000	$0.000	$0.000	
		$0.052	**$0.052**	**$0.052**	**$0.052**	**$0.052**	**5%**
Total Costs	CapEx/OpEx	$1.139	$0.659	$0.521	$0.445	$0.691	
	Utilities	$0.276	$0.287	$0.287	$0.287	$0.284	
	Chemicals	$0.058	$0.058	$0.058	$0.058	$0.058	
		$1.474	**$1.004**	**$0.866**	**$0.790**	**$1.033**	**100%**
Total Costs	**CapEx/OpEx**	**$0.886**	**$0.533**	**$0.425**	**$0.366**	**$0.553**	
no De-oiling	**Utilities**	**$0.196**	**$0.204**	**$0.204**	**$0.204**	**$0.202**	
	Chemicals	**$0.058**	**$0.058**	**$0.058**	**$0.058**	**$0.058**	
		$1.140	**$0.795**	**$0.687**	**$0.629**	**$0.813**	
Sum of Costs for Separation		**$0.487**	**$0.293**	**$0.245**	**$0.219**	**$0.311**	
and Deoiling							
Total w/o Separtation & Deoiling		**$0.986**	**$0.710**	**$0.621**	**$0.571**	**$0.722**	

This table provides the basis for reducing the costs associated with de-oiling and water/oil/water separation that may not be required with injection/storage operations involving producing water for pressure management, but for which no oil and/or CO_2 are produced in association with the water.

Based on our estimates in this memo, total costs of water management are estimated to be $0.64 per barrel of water produced, as shown below:

		Cost Estimate ($/bbl water)
Production	Wells	$0.14
	Lease Equipment	$0.01
	Lifting and Transport	$0.25
		$0.40
Injection	Wells	$0.14
	Injection Equipment	$0.01
	OpEx	$0.04
	Energy	$0.05
		$0.24
TOTAL		**$0.64**

These compare reasonably to the estimates in the *Oilfield Review* article.

In addition, Jackson and Myers[29,30] provided cost estimates for many produced water disposal methods that might be used in Rocky Mountain States. They reported produced water management costs for secondary recovery ranging from $0.05 to $1.25 per barrel, and for shallow reinjection of $0.10 to $1.33 per barrel. Again, our estimated costs are in the middle of this range.

More sophisticated water treatment and reuse options could be considered. However, the costs associated with such applications can vary widely, and depend on produced water characteristics and the application for which the produced water will be used. Such applications can range from reuse in oil and gas operations (for example, as a source for water used in hydraulic fracturing or for waterflooding operations), industrial applications, agricultural applications (irrigation or

[29] Jackson, L., and J. Myers, "Alternative Use of Produced Water in Aquaculture and Hydroponic Systems at Naval Petroleum Reserve No. 3," presented at the 2002 Ground Water Protection Council Produced Water Conference, Colorado Springs, CO, Oct. 16-17, 2002. (Paper available at http://www.gwpc.org/Meetings/PW2002/Papers-Abstracts.htm)

[30] Jackson, L.M., and J.E. Myers, "Design and Construction of Pilot Wetlands for Produced-Water Treatment," SPE 84587, presented at the SPE Annual Technical Conference and Exhibition, Denver, CO, Oct. 5-8, 2003

livestock), hydrological uses (such as subsidence or salt water intrusion control), or can be treated to drinking water standards. Veil, et al. provided a discussion of such options.[31]

A comprehensive evaluation of the costs associated with such a diverse set of water treatment options is beyond the scope of this assessment.

7 "Next Generation" CO_2-EOR Costs

To be consistent with the most recent U.S. CO_2-EOR assesments performed for DOE/NETL,[32] four additional modifications need to made to the costing assumptions model to account for the additonal costs of applying "next generation" CO_2-EOR technologies.

These are described below.

7.1 Accounting for Increased Volumes for CO_2 Injection

"Next generation" CO_2-EOR assumes that increased volumes of CO_2 will be injected, relative to that in the "state-of-the-art" case. Specifically, it assumes that 1.5 hydrocarbon pore volume (HCPV) will be injected. This translates into a higher peak rate assumed for CO_2 injection (that will come out of the PROPHET model runs), and therefore higher costs for CO_2 injection and recycling. These costs for purchasing, recycling, and injecting the 1.5 HCPV of CO_2 would be determined automatically by the costing model given the higher peak rates and total volumes of CO_2 injection.

7.2 Innovative Flood Design and Well Placement

The "next generation" costs should assume that one additional new vertical production well would be added to each pattern. This well would produce from previously bypassed or poorly contacted portions of the reservoir. (The model assumes that each pattern already has, or drills, one production and one injection well.)

7.3 Viscosity Enhancement

"Next generation" costs should assume that the water injection costs for the CO_2-Water-Alternating-Gas (WAG) process are increased by $0.25 per barrel of injected water to account for the addition of viscosity enhancers and other mobility control agents or actions.

7.4 Flood Performance Diagnostics and Control

"Next generation" costs should assume that the "next generation" CO_2-EOR project is supported by a fully staffed technical team (geologists, reservoir engineers, and economic analysts), uses a

[31] Veil, J.A., C.B. Harto, and A. T. McNemar, "Management of Water Extracted from Carbon Sequestration Projects: Parallels to Produced Water Management," SPE Paper No. 140994 presented at the SPE Americas E&P Health, Safety, Security, and Environmental Conference, Houston, Texas, March 21-23, March 2011

[32] U.S. Department of Energy, National Energy Technology Laboratory, *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-Enhanced Oil Recovery (CO_2-EOR)*, DOE/NETL-2011/1504 prepared by Advanced Resources International, June 2011 (http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&Source=Main&PubId=391)

series of observation wells and downhole sensors to monitor the progress of the flood, and conducts periodic 4-D seismic plus pressure and residual oil saturation measurements to "optimize, manage, and control" the CO_2 flood. It should be assumed that this adds 10 percent to the initial capital investment and 10 percent to the annual operating costs of the CO_2 flood to cover these extra costs.

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