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Feasibility Study for Ship Based Transport of Ethane to Europe and Back Hauling of CO\textsubscript{2} to the USA

Overview

This feasibility study was commissioned by the IEA Greenhouse Gas R&D Programme on behalf USDOE. The study was led by Fern Oil Inc. (A Division of Astrup-Fearnleys AS) of the USA.

The study is a first stage assessment of a novel concept of transporting ethane from the USA in dedicated maritime carriers to Europe, which are modified from standard designs to be equipped to carry both ethane and CO\textsubscript{2}, so that CO\textsubscript{2} can be transported back (back hauled) to the USA for use in CO2-EOR operations.

Transportation of Ethane to Europe. The Shale gas boom in the United States has also resulted in the production of liquid products like ethane, at competitive prices. In 2016, the USA began exporting ethane first by pipeline to Canada and then by liquefied carrier to Norway in March 2016 and the UK in September 2016\textsuperscript{1}. Ethane is used as a key feedstock for plastics production and other industrial uses and is expected to boost UK and Norwegian production of such products as supplies from the North Sea begin to decline.

INEOS a global manufacturer of petrochemicals, speciality chemicals and oil products, secured 15 year contracts for the purchase, distribution and shipping of ethane from the US, underpinning the economics of its petrochemicals assets in Europe for the foreseeable future. INEOS partnered with Evergas, (Danish shipbuilding experts) to build a new class of vessels, the Dragon Class to transport the ethane across the Atlantic. To date 4 such vessels have been built and 4 more will be launched in 2017\textsuperscript{2}. The Dragon-class vessels are equipped with autonomous C type bi-lobe tanks, which store 27,500m\textsuperscript{3} of gases, such as liquefied natural gas (LNG), ethane, liquefied ethylene gas (LEG), and liquid petroleum gas (LPG)\textsuperscript{3}.

Adapting Ethane Carriers to Back Haul CO\textsubscript{2}. The study has examined from first principles the potential to design new ethane carriers to also carry CO\textsubscript{2}. The starting premise was that LNG carriers in Norway have been designed to carry both LNG and CO\textsubscript{2}. The Norwegian shipping company IM Skaugen has six 10,000 m\textsuperscript{3} ships in their fleet which are rated to 7 bar, -104\degree C, and are registered for carrying liquefied CO\textsubscript{2} (LCO\textsubscript{2}), however, their normal cargo is LPG. It is not clear from the literature if the ships have been used yet for CO\textsubscript{2} transport\textsuperscript{4}. The ships are smaller in scale than the Dragon class vessels and not suitable for transporting liquefied gas across the Atlantic.

The study concludes that technically it could be feasible to build new multi fuel vessels like the Dragon class ship that could transport LCO\textsubscript{2} as well as other gases. One of the challenges highlighted in the study is the maximum allowable working pressure of the cargo tank that would be needed to transport LCO\textsubscript{2} is higher than that for LPG service which could cause design issues. However it is accepted that these issues have been resolved for the smaller dual LNG/CO\textsubscript{2} vessels identified above. It is felt that existing carriers may not be suitable for conversion to carry LCO\textsubscript{2} but future new build vessels could consider this design adaptation, if the construction of new vessels are being planned to meet future export demand for liquefied shale gas products.

\textsuperscript{2} http://www.ineos.com/big-boats
\textsuperscript{3} http://www.ship-technology.com/projects/dragon-class-liquid-gas-transport-vessels/
\textsuperscript{4} http://www.sccs.org.uk/images/expertise/misc/SCCS-CO2-EOR-JIP-Shipping.pdf
**Market Demand for CO₂ in the USA.** The driver for transporting CO₂ to the USA is the projected increase in the demand for CO₂ for EOR in the USA. The study concludes that the single largest constraint to CO₂-EOR growth in the USA is the lack of sufficient economically viable sources of CO₂ in the USA itself. Hence the desire to consider off shore supplies for CO₂ to the USA to meet future growth and demand for CO₂ for EOR in the USA. It should be noted that at the time of the study the price of oil stood around $100 per barrel, since then the price has dropped considerably and this will reduce the growth of domestic CO₂-EOR in the USA for several years to come. The projected demand for CO₂ in the USA was 9-26 billion tonnes per annum for conventional CO₂-EOR operations. Considering residual oil play demand could increase this demand projection for CO₂ by 75%.

The study did not undertake any economic analyses to consider what a price for exported CO₂ from Europe might look like and whether this fits the cost model for CO₂ for EOR in the USA.

**Production of CO₂ for shipping in Europe.** Large point source emissions in Europe equated to 1.5Gt CO₂ in 2005, of which 400 emission sources accounted for 75% of those emissions⁵. There is therefore more than sufficient CO₂ to meet the CO₂-EOR demand in the USA. However, whilst there are a significant number of point sources of CO₂ in continental Europe that could supply CO₂ there are currently no CCS projects that are operational in Europe that could provide CO₂ for export to the USA. The first project that could come on board is the ROAD project in the Netherlands around 2018-2020, the CO₂ will be used for greenhouses and injection into a gas field⁶. This project has been significantly delayed to date and its actual start date remains uncertain. It is only currently planned to operate for 3 years. After, that the only planned projects are in Norway which will not come on stream until 2022 onwards⁷. There is currently no infrastructure to transport CO₂ in the volumes needed to allow it to be exported. Such an infrastructure is not likely to be built before 2025 at the earliest.

Current market value for CO₂ in the USA is of the order $10-30/t. Such a price will not on its own stimulate the development of CCS projects and pipeline infrastructure in Europe to supply the US market, but it could help facilitate such development in the future.

**Conclusions**

The report considers a conceptual idea for transporting CO₂ to the USA in modified ethane carriers. The main conclusion that can be drawn are:

1. Whilst ethane is being exported to Europe now the same ships are unlikely to be converted to carrier LCO₂ as well. New ships would need to be built to meet any market demand to back haul CO₂ to the USA.
2. Whilst there is a potential near term demand for CO₂ for EOR in the USA (if oil process recover to $100/barrel), there is unlikely to be large quantities of transportable CO₂ from Europe in the foreseeable future.

In summary, this is an interesting concept and one that should not be dismissed out of hand. But all the pieces of the jigsaw do not slot into place at the current time and may not conceivably do so in the next 5-10 years.

It is also noted that LPG and ethane trades to the Far East from the US Gulf Coast are also now starting and there may be similar considerations on those routes for future investigations of this type.

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⁵ IEAGHG Report 2005/02 Building the Costs Curve for Storage in Europe, February 2005
Feasibility Study of
Ship-Based Transportation of CO₂

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The Potential for Dual Fuel Transatlantic and Transpacific LPG/Ethane Carriers for
Shipping CO₂ from CO₂ Capture Centres to CO₂ Utilisation Centres

Phase 1 Feasibility Concept Study

Prepared by:
Fearn Oil

In association with:
ABS Consulting
Advanced Resources International, Inc.
University of Wyoming, School of Energy Resources
Carbon Management Institute

April 20, 2016
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Feasibility Study of Ship-Based Transportation of CO₂

Executive Summary

This preliminary examination of the feasibility of using ship-based transportation of CO₂ has been conducted as part of U.S. Department of Energy’s (DOE) Quadrennial Energy Review (QER) as directed by the 2014 Presidential Memorandum. The QER, issued in April 2015, focuses on the current and future status of the U.S. energy infrastructure and its ability to promote economic competitiveness, energy security and environmental responsibility, notably mitigation of climate change.

Ship-based transportation of CO₂, as assessed in this preliminary feasibility study, involves the transport of surplus natural gas liquids (NGLs) composed of ethane and liquid petroleum gasses (LPGs) from the U.S. to international markets, with CO₂ transported as “backhaul” to U.S. markets. The landed CO₂ in the U.S. would be used and stored by the domestic CO₂ enhanced oil recovery (CO₂-EOR) industry, Figure EX-1.

Figure EX-1. Hypothetical Voyage: Loading Ethane in Marcus Hook, New Jersey, Discharging Ethane in NW Europe (red line), Loading CO₂ in Rotterdam, Discharging in U.S. Gulf Coast (green line)

Source: ABSC / google maps
An independent appraisal of the feasibility of ship-based transportation of CO₂ conducted by ABS Consulting as part of this assessment concluded that “from a technical standpoint, liquid CO₂ can be carried aboard suitable liquefied gas vessels with approvals, precautions and handling procedures similar to those used for other liquefied gas (LNG, LPGs, etc.) carried as cargo aboard ships.” Further discussion of the feasibility and challenge of ship-based transportation of CO₂ is provided below and in the remainder of this report.

1. Ship-Based Transportation of CO₂ and U.S. Energy Security. Our Phase I study of the feasibility and market potential of using ship-based transportation of CO₂ finds that this innovative infrastructure option would significantly support the U.S. energy and climate change goals set forth by DOE in the QER. For example:

- Ship-based transportation of CO₂, shipping CO₂ from countries or areas with challenging CO₂ storage options to the CO₂-EOR market in the U.S., would support American climate change diplomacy goals while enhancing the economic competitiveness and viability of the U.S. CO₂-EOR industry and thus domestic energy security.

- A substantial market exists in the U.S. for reliable, affordable anthropogenic CO₂ supplies (CO₂ emissions) captured from industrial facilities and power plants. The recent recognition and appraisals of residual oil zone (ROZ) resources has expanded the market for CO₂ substantially.

- The U.S. has large, growing volumes of natural gas liquids (ethane and LPG) production that are already being exported, with large additional resource potential that could be exportable. NGLs are by-products of natural gas production and need to be separated from natural gas to enable this product to meet pipeline and market specifications. As such, the natural gas and NGL production industry needs increased export markets to promote a viable domestic industry.

2. Technical and Economic Feasibility of Ship-Based Transportation of CO₂. Based on discussion with CO₂ pipeline operators, U.S. Coast Guard engineering and hazardous materials staff, cryogenic pump makers and LPG vessel operations executives, from a technical standpoint liquid CO₂ can be carried aboard suitable liquefied gas vessels with approvals, precautions and handling procedures similar to those used for other liquefied gases carried as cargo aboard ships.
Quoting an email message received from a senior executive of a well-established European liquefied gas carrier with long experience in the transport of cryogenic liquid gases, “Technically, transporting CO₂ is not a big deal. (You) (j)ust have to choose temp/pressure to optimize your supply chain”.

The biggest challenge in utilizing existing liquefied gas carriers for transport of liquefied CO₂ (LCO₂) is the maximum allowable working pressure of the cargo tank, which would be higher than that used for regular LPG service. Although there are existing liquefied gas carriers capable of carrying LCO₂, because of the requirement for increased pressure capability, they are generally smaller and less suited to long-haul trans-Atlantic transport. Suitable vessels for LCO₂ backhaul service would fall into the “handy-size” gas carrier category; vessels with approximately 15,000 cubic meters (m³) to 30,000 m³ capacity.

Existing designs of “handy-size” liquefied gas carriers would need to be tailored at the newbuild design stage to make carriage of LCO₂ possible. There may be an opportunity to take advantage of increased numbers of newbuild orders to specify LCO₂ capable ships at a cost which should be only marginally higher than the cost of a standard liquefied gas carrier.

3. Increasing Volumes of Domestic NGL (Ethane, LPGs) Production. The U.S. “shale gas revolution” has enabled domestic natural gas production to fully meet U.S. needs and also support a vibrant LNG export industry. In addition, the “shale gas revolution” has also led to large volumes of natural gas liquids (NGLs) production (ethane plus propane, butane and pentane (LPGs)). This growth in natural gas and by-product NGL production has been so large and so rapid that it has exceeded domestic demand, enabling the U.S. to become a large net exporter of LNG and particularly NGLs, Exhibit EX-2. As shale gas production continues to grow, NGL exports will also need to grow, providing a strong base of export product for ship-based transportation of ethane and other LPGs to global markets. In addition, the U.S. contains a significant technically recoverable resource base that, under favorable demand and price conditions, could provide the foundation for more growth in NGL and LPG supplies for many years to come.
4. **CO₂ Market from the U.S. CO₂-EOR Industry.** The U.S. has an active and growing CO₂-EOR industry, built on proven technology and several decades of successful application. Today there are 136 distinct CO₂-EOR projects underway in the U.S., using 3.5 billion cubic feet per day (Bcf/d) of purchased CO₂, while facilitating about 300,000 barrels per day of crude oil production from a diversity of geological and geographic settings. Notable is the availability of a major CO₂ transportation network in the Gulf Coast area of the U.S., Figure EX-3.

CO₂-EOR based oil production has grown steadily in the past ten years, supported by the availability of both natural and industrial CO₂ supplies. Recently, the CO₂-EOR industry has established new “footholds” in the Gulf Coast and Mid-Continent drawing on industrial supplies of CO₂. However, the single largest constraint to greater production of domestic oil using CO₂-EOR is still the lack of sufficient, economically viable supplies of CO₂.

The initial target for CO₂-EOR is the 414 billion barrels of oil “left behind” in the main pay zones of existing U.S. oil fields. Of this, 284 billion barrels is technically feasible for CO₂-enhanced oil recovery, creating a demand for 9 to 26 billion metric tons of CO₂.
In addition to the oil “left behind” after primary and secondary recovery in the main pay portion of an oil reservoir, a large remaining oil target often exists in the lower portion of an oil reservoir (below the reservoir’s water-oil contact) called the residual oil zone (ROZ). Advanced Resources has documented the presence of an additional 192 billion barrels of residual oil in-place in the San Andres Formation’s ROZ “fairways” in a twelve-county area of the Permian Basin, West Texas. Reservoir modeling by Advanced Resources shows that significant volumes of the oil in-place in the ROZ is technically recoverable using miscible CO₂-EOR, with the “higher quality” portions of this resource offering promise for commercial viability at moderate oil prices.

5. Numerous Precedents Exist for Ship-Based Transportation of CO₂. The transportation and import (as well as export) of liquefied gas into the U.S. is well established with the development of the LNG industry. In addition, the precedent for trans-boundary movement of CO₂ has been established with the transportation of CO₂ from the U.S. (Dakota Gasification Facility) to Canada (Weyburn Oil Field) for use by CO₂-EOR. Additional discussion of this topic, including areas for further investigation, are provided in Chapter 1 and the Appendix to this report.
Proposed Next Steps.

To more rigorously establish the viability of ship-based transportation of CO₂, we propose the following next steps:

1. **Undertake a Detailed Design Study for System Modifications and Additional Examination of Vessel Specification for Transport of LCO₂.** The ABS study finds that the CO₂ backhaul concept is technically feasible with appropriate precautionary measures. Additional study identifying specific vessels, containment system modification requirements, trade routes, actual CO₂ sellers and buyers, load and discharge ports, and infrastructure requirements need to be completed to further establish the technical viability of this CO₂ transportation option.

2. **Provide Detailed Examination of the Economic Feasibility of Ship-based Transportation of CO₂.** Of particular interest would be: (1) defining the additional shipping distances and offloading time requirements for backhauling LCO₂ to U.S. ports in the Gulf Coast and possibly the West Coast, (2) establishing the capital costs for modifying the vessels and port facilities to handle LCO₂ transport and loading, and (3) estimating the “marginal” and “full” costs of transporting LCO₂ as a backhaul for NGL shipments.

3. **Provide Long-Term Market Study of U.S. Ethane and LPG Production and Exports.** This market study would define the outlook for future domestic NGL (ethane and LPG) production, the demand for NGLs by the domestic petrochemical industry, and the excess NGL productive capacity needing export markets.

4. **Provide a Long-Term Market Study for CO₂ Demand by the CO₂-EOR Industry.** Of particular interest would be the size, economic viability and CO₂ demand by the CO₂-EOR industry along the Gulf Coast of the U.S.

5. **Further Define the Regulatory and Legal Issues Associated with Ship-Based Transportation of CO₂.** While certain precedents exist for importing liquefied gases into the U.S. and for trans-border movement of CO₂, potential legal and regulatory issues that may need to be addressed exist; thus, further examination of these issues, as described in the Appendix, is warranted.
Feasibility Study of Ship-Based Transportation of CO₂

Chapter 1
Overview of Report

Prepared by:
Advanced Resources International, Inc.
Feasibility Study of Ship-Based Transportation of CO₂

Overview of Report

This preliminary examination of the feasibility of using ship-based transportation of CO₂ has been conducted as part of U.S. Department of Energy's (DOE) Quadrennial Energy Review (QER) as directed by the 2014 Presidential Memorandum. The QER, issued in April 2015, focuses on the current and future status of the U.S. energy infrastructure and its ability to promote economic competitiveness, energy security and environmental responsibility, notably mitigation of climate change. One of the major findings of the QER is that innovation at the systems level offers real potential for revolutionary changes to the ways we deliver and use energy. This would, in this case, also apply to the ways in which we facilitate commercially viable approaches for reducing greenhouse gas (GHG) emissions.

Significant parts of the world have the potential for capturing CO₂, from power and other industrial plants, but few opportunities exist globally for productively using or selling this CO₂ for enhanced oil recovery and by-product CO₂ storage. The introduction of tanker ships for transporting CO₂ from source to use would help overcome this barrier to efficient international carbon capture, utilization, and storage (CCUS).

Moreover, the development of liquids-rich shale gas has greatly expanded the production and supply of ethane and LPGs (propane, butane, and pentane) in the U.S., to the point where supply exceeds demand and ethane/LPG exports are now common. Continued growth in liquids-rich shale gas promises a continuation of this situation considerably into the future.

On the other hand, the large stock of mature U.S. oil fields, facing near-term abandonment, desperately need additional supplies of CO₂ for enhanced oil recovery.

One pathway for enhancing the economic viability of this option is to use existing LPG/ethane carriers with modifications (or specifically designed dual-purpose LPG/CO₂ carriers), particularly since, in the return portion of the voyage, an LPG carrier is typically empty.

Ship-based transportation of CO₂, as assessed in this preliminary feasibility study, involves the transport of surplus natural gas liquids (NGLs) composed of ethane and liquid petroleum gasses (LPGs) from the U.S. to international markets, with CO₂ transported as
“backhaul” to U.S. markets. The landed CO₂ in the U.S. could be primarily used and stored by
the domestic CO₂ enhanced oil recovery (CO₂-EOR) industry, Figure 1-1.

Figure 1-1. Hypothetical Voyage: Loading Ethane in Marcus Hook, New Jersey, Discharging
Ethane in NW Europe (red line), Loading CO₂ in Rotterdam,
Discharging in U.S. Gulf Coast (green line)

Source: ABSC / google maps

A series of initial studies, by Chiyoda (“Preliminary Feasibility Study on CO₂ Carriers for
Ship-Based CCS,” October 2011) and by Lloyd’s Register (“Feasibility of Danish CCS Scheme
Comprised by Capture at Power Plants, Ships Transport and CO₂ EOR,” May, 2011), have
provided preliminary information establishing the technical viability of this CCUS option. However,
numerous issues remain to be defined and assessed, particularly on the technical, commercial
and regulatory feasibility of implementing this strategy in the U.S.

As such, the building blocks for a U.S. strategy of exporting LPGs and importing CO₂ for
EOR and associated storage are in place. What is missing is more detailed information for further
defining, assessing and implementing such a strategy.
1. Technical and Economic Feasibility of Ship-Based Transportation of CO₂ as a Backhaul for NGL Transport

As part of this preliminary feasibility assessment, an analysis was performed to determine whether carriage of liquid CO₂ is a feasible backhaul option for natural gas liquids (NGLs) and liquefied petroleum gas (LPG) shippers. The objective would be maximize utilization of existing or proposed vessels in liquefied gas service loading cryogenic liquid gases at U.S. Gulf of Mexico or Atlantic coast ports as an alternative to returning to the U.S. in ballast (empty of cargo). The source of the liquid CO₂ (LCO₂) would be CO₂ capture projects in Europe or other locations (such as Asia) to be specifically determined at a future development phase. The study examined the technical, operational and regulatory compliance issues to be considered for liquefied-gas vessels to be used for backhaul cargos of LCO₂.

In the context of this report, to avoid confusion with multiple marine vessel categories and types, the term liquefied gas carrier is used to cover the entire range of vessels with the technical capacity to carry liquid gases, including CO₂. The term natural gas liquids (NGLs) is used throughout this report and covers the spectrum of liquefied gases carried by ship. The term liquefied petroleum gas (LPG) is used in the shipping industry to refer mainly to propane and butane (see Table 1-1 for description of NGLs).

<table>
<thead>
<tr>
<th>Natural Gas Liquid</th>
<th>Chemical Formula</th>
<th>Applications</th>
<th>End Use Products</th>
<th>Primary Sectors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethane</td>
<td>C₂H₆</td>
<td>Ethylene for plastics production; petrochemical feedstock</td>
<td>Plastic bags; plastics; anti-freeze; detergent</td>
<td>Industrial</td>
</tr>
<tr>
<td>Propane</td>
<td>C₃H₈</td>
<td>Residential and commercial heating; cooking fuel; petrochemical feedstock</td>
<td>Home heating; small stoves and barbecues; LPG</td>
<td>Residential, Commercial</td>
</tr>
<tr>
<td>Butane</td>
<td>C₄H₁₀</td>
<td>Petrochemical feedstock; blending with propane or gasoline</td>
<td>Synthetic rubber for tires; LPG; lighter fuel</td>
<td>Industrial, Transportation</td>
</tr>
<tr>
<td>Isobutane</td>
<td>C₄H₁₀</td>
<td>Refinery feedstock; petrochemical feedstock</td>
<td>Alkylate for gasoline; aerosols; refrigerant</td>
<td>Industrial</td>
</tr>
<tr>
<td>Pentane</td>
<td>C₅H₁₂</td>
<td>Natural gasoline; blowing agent for polystyrene foam</td>
<td>Gasoline; polystyrene; solvent</td>
<td>Transportation</td>
</tr>
<tr>
<td>Pentanes Plus*</td>
<td>Mix of C₅H₁₀ and heavier</td>
<td>Blending with vehicle fuel; exported for bitumen production in oil sands</td>
<td>Gasoline; ethanol blends; oil sands production</td>
<td>Transportation</td>
</tr>
</tbody>
</table>

*Pentanes plus is also known as "natural gasoline." Contains pentane and heavier hydrocarbons.

Source: U.S. Energy Information Administration
As a result of improved onshore oil and gas extraction technologies over the last decade, U.S. domestic oil and gas fields produce significant quantities of oil, natural gas and natural gas liquids (NGLs). As a result, NGLs have become available for export as a result of supply exceeding demand in the U.S. (See discussion below and in Chapter 3). Until recently, U.S. export capability has been limited, but major NGL export projects have been developed in the U.S. and are now coming on stream to supply energy products to world markets. NGLs are in demand globally as a feedstock for various industrial and chemical processes.

NGL exporting involves the use of specialized ships known as liquefied gas carriers with pressurized cargo tanks and cargo handling systems capable of carrying liquefied gases with temperatures as cold as -160°C (-260°F) throughout a range of pressures. These ships are designed and built according to stringent international design criteria to permit safe transport and handling of cryogenic and pressurized liquid gases. The types of ships that can carry NGLs and LPGs are shown in Figure 1-2.

The biggest challenge in utilizing existing liquefied-gas carriers is the maximum allowable working pressure of the cargo tank, which would be higher than that used for regular LPG service. Although there are existing liquefied gas carriers capable of carrying LCO₂, because of the requirement for increased pressure capability, they are generally smaller and less suited to long-haul trans-Atlantic transport.

Basic vessel technical requirements for carrying LCO₂ are:

- Type 2G or 3G liquefied gas carrier with, or capable of being approved for, a Certificate of Fitness for liquid CO₂
- Type C (pressure vessel) containment system with greater than 7 Bar g design pressure and appropriate safety margin
- Tanks and cargo systems suitable for cryogenic liquid gases colder than -55°C
- Permission from the relevant authorities to carry liquid CO₂
- Sufficient cargo carrying capacity to allow competitive unit freight costs.
Suitable vessels for LCO₂ backhaul service would fall into the “handy-size” gas carrier category; vessels with approximately 15,000 m³ to 30,000 m³ capacity. The notional candidate vessels identified in this report have less than 15,000 m³ cargo capacity.

Increased U.S. NGL exports are driving requirements for more liquefied gas carriers to lift cargos from Gulf and East coast ports. Existing designs of handy-size liquefied gas carriers are a close fit, but would need to be tailored at the new-build design stage to make carriage of LCO₂ possible. There may be an opportunity to take advantage of increased numbers of handy-size new-build orders to specify LCO₂ capable ships at a cost which should be only marginally higher than the cost of a standard liquefied gas carrier.

Potential time loss and the logistical and operational elements of changing cargo grades and voyage deviations will also significantly affect the feasibility of LCO₂ backhaul on a specific trade route, charter, or contract of affreightment. The potential for net hydrocarbon emissions...
increases also has to be evaluated in the context of environmentally responsible shipping and CCS project objectives.

A variety of economic and operational factors of moderate complexity and likelihood must be aligned in order for ship-owners to regard LCO$_2$ backhaul as an attractive market. These include:

- Availability of suitable vessels with the requisite cargo tank design pressure
- Development of needed infrastructure (CO$_2$ storage and marine transfer facilities)
- Long term commitment of project stakeholders, including shippers and CCS project developers and sponsors
- Sufficient economic inducement for all participants in the value chain.

In general, the CO$_2$ backhaul concept is technically feasible with appropriate precautionary measures. Favorable shipping and logistics factors provide support and opportunity for development of the concept. Additional study identifying specific vessels, containment system modification requirements, trade routes, actual CO$_2$ sellers and buyers, load and discharge ports, and infrastructure requirements must be completed for proof of concept.

Based on these criteria for carriage of CO$_2$ and the initial shipping considerations described above, a number of existing vessels have been identified as being potentially CO$_2$ capable based on their capacity and permitted cargos. According to information from Clarkson’s shipping database, there are approximately thirty pressurized liquefied gas carriers currently in service that could be considered suitable (Table 1-2). These vessels represent part of the potential available pool from which CO$_2$ backhaul candidates could be chosen. Further study would be needed to identify specific ships that meet the technical requirements to carry CO$_2$ matched with trading routes that could facilitate CO$_2$ backhaul cargos and ship owners and charterers with sufficient incentive to accept them.

Note that this is a preliminary screening and that the ships listed above are notional candidates based on capacity and cargo type. Confirmation by the ship owner of LCO$_2$ technical capability and issuance of a Certificate of Fitness listing LCO$_2$ as a permitted cargo would be the required next step.
Table 1-2. Candidate Ships Based on Potential LCO\textsubscript{2} Capability Listed by Capacity  
(Source: Clarkson’s)

<table>
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Although it is technically feasible to carry LCO₂ in liquefied gas carriers, such as those identified in Table 1-2, it is important to recognize that there are many challenges to be met before CO₂ backhaul can be incorporated into current trading routes.

Existing LCO₂ dedicated vessels are not suited for long haul, cost efficient transport of LCO₂. The LCO₂ capable liquefied gas carriers listed in Table 1-2 may not have sufficient cargo carrying capacity for cost efficient trans-Atlantic voyages.

Absent the current lack of CO₂ supply, active CO₂ trading markets and supporting infrastructure, the most significant challenge is to find existing or on-order ships with cargo tanks that can accommodate the higher pressure required to safely and efficiently carry CO₂.

Further study to include direct surveys of ship owners with vessels operating in LPG service is recommended to identify specific ships meeting these criteria:

- Type 2G or 3G liquefied gas carrier with, or capable of being approved for, a Certificate of Fitness for liquid CO₂
- Type C (pressure vessel) containment system with greater than 7 Bar g design pressure and appropriate safety margin (Note that lower design pressures may be possible if confirmed by operational evaluation)
- Tanks and cargo systems suitable for cryogenic liquid gases
- Permission from the relevant authorities to carry liquid CO₂
- Sufficient cargo carrying capacity to allow competitive unit freight costs.

Existing designs of handy-size liquefied gas carriers are a close fit, but would need to be modified at the newbuild stage with cargo tanks of sufficient design pressure to accommodate carriage of CO₂.

It is possible that new-build vessels designed for LCO₂ as well as NGLs may provide a better marine transport solution as the U.S. NGL export market and the CCS market evolves.

Liquefied gas carriers could be changed to accommodate carriage of CO₂ by increasing the cargo tank design pressure. It is expected that the cost of the required modifications should
be only marginally higher than for a standard liquefied gas carrier, but an evaluation of cost in relation to the specific LCO₂ opportunity is recommended.

In order for the concept to work as intended, sufficient monetary inducements to charterers to offset the daily hire rate of the vessel must be offered.

There is also an opportunity cost to be quantified depending on a number of factors:

- Cost to deviate or reposition from the load and discharge ports specified in the charter
- Charterer’s willingness to deviate from set voyage routes
- Available backhaul cargos that are more attractive economically, operationally or logistically
- Potential for delayed or missed scheduled loading and related commercial penalties
- Cargo changeover and preparation time costs
- Environmental impacts—hydrocarbon emissions from cargo changeover, carbon emissions offset considerations from potential CO₂ venting.

Current CO₂ marine storage and transfer infrastructure is currently not sufficiently developed to support large scale movement of LCO₂. Collaboration in the form of a joint industry project (JIP) or similar venture between CCS projects, ship owners, LPG shippers, CO₂ end users, regulatory bodies and industry organizations is recommended to develop a coordinated solution incorporating marine transportation of CO₂ that optimizes existing and planned transportation, storage and distribution infrastructure.
2. Status and Outlook for U.S. Natural Gas Liquids Supply and Demand

After nearly twenty years of decline, domestic NGL production hit a low of 1.6 million barrels per day (MMB/D) in 1990. With expectations of scarcity and higher prices for natural gas, much of the domestic petrochemical industry, particularly along the Mississippi River, relocated to areas with more secure, accessible supplies of NGLs as well as naphtha, an alternative to using NGLs as feedstock in chemical plants.

Subsequently, NGL production rebounded and then stayed relatively flat at 1.8 to 1.9 MMB/D through 2008, but this rebound was met with skepticism by industry as to its sustainability. As such, industry’s pessimistic outlook for future NGL production remained entrenched and petrochemical operations continued to relocate overseas, relying primarily on naphtha as the preferred feedstock for ethylene production.

However, since 2008, U.S. production of NGLs (from gas plants) has surged – from 1.8 million barrels per day in 2008 to 3.0 million barrels per day in 2014, Figure 1-3.

![Figure 1-3. Domestic Natural Gas Liquids Production](image-url)

Source: U.S. EIA, 2015
This dramatic change in the domestic NGL supply situation has been brought about by the “shale gas revolution”, particularly the discovery and development of wet, liquids-rich shale gas plays such as the Woodford, SW Marcellus, and Utica. Additionally, liquids-rich associated gas from “tight oil” plays such as the Bakken, Eagle Ford and the stacked formations of the Permian further boosted NGL supply.

Much of the growth in domestic NGL supply has been from increased production of ethane and propane. Ethane production increased by 0.4 MMB/D -- from 0.7 MMB/D in 2008 to 1.1 in 2014 -- despite rejection of an estimated 0.8 MMB/D of technically recoverable ethane in 2014. Meanwhile, propane production increased by 0.5 MMB/D over this same time period, from 0.5 MMB/D to 1.0 MMB/D. In addition, production of iso-butane, normal butane, and pentane (natural gasoline) increased by a combined 0.4 MMB/D, from 0.6 MMB/D to 1.0 MMB/D. Figure 1-4 illustrates the recent growth of NGL production by the five key product streams.

Figure 1-4. Growth of Domestic NGL Supply, by Product

With the strong growth in domestic NGL production, in 2011 the U.S. became a net exporter of natural gas plant liquids and liquefied refinery gases for the first time since the data for imports/export of NGLs has been recorded.
Ethane. The primary driver of ethane demand is feedstock for production of ethylene and other chemicals in competition with naphtha. With increasing production of low cost wet (liquids-rich) natural gas, the cost advantage of producing ethylene from ethane has stimulated expansion and new construction of ethane crackers. Additionally, dedicated ethane pipelines, export terminals, and tankers are under development. However, increases in domestic ethane production have greatly exceeded growth in domestic demand. As such, increased ethane exports are needed to remedy the current surplus situation and low price.

Propane. Propane, the most seasonal of the NGL streams, is used in a variety of capacities, from residential heating in the winter, to agricultural use in the fall and petrochemical use year round. With the steady growth of domestic propane production, Figure 1-5, the U.S. began exporting propane in 2011 and exported 0.4 MMB/D of propane in 2014 (0.3 MMB/D, net), Figure 1-65. The exports primarily depart from Gulf Coast terminals located in close proximity to the large NGL processing complex at Mont Belvieu, TX. Additionally, propane is also exported from the Marcus Hook facility on the East Coast. Proposed West Coast propane export terminals in Oregon and Washington are in the early stages of planning.

Butane and Pentane. Normal butane can be used for gasoline blending and as a petrochemical feedstock, whereas isobutene is primarily used in the production of motor gasoline by refineries. Pentane is primarily used as a blending stock for transportation fuel and as a diluent for heavy oil. These heavier NGL components, iso and normal butane and pentanes plus, are largely consumed domestically. However, in 2014 the U.S. exported a modest volume of butane (55 MB/D, net) and a moderate volume of pentane (152 MB/D, net).
**NGL Pricing.** NGL prices have collapsed in the last two years due to oversupply and a decline in the price of oil. In the Marcellus, one of the primary regions of NGL supply growth, NGL prices have been hit particularly hard, declining by over 70% in the 18 month period ending in mid-2015.

Ethane, currently with a Mt. Belvieu price of $7.80/B ($0.19/gal or ~$2.80/MMBtu), is being rejected widely as operators often receive more value by keeping ethane in the gas stream than by processing it. Similarly, propane prices have collapsed as well, with current prices of about $16.80/B ($0.40/gal or $4.40/MMBtu).

Driving the economics of exporting ethane is the price spread between ethane and naphtha, which has favored ethane over the past few years due to the lower cost of ethane and a higher oil price. Overseas, many of the crackers used for the production of propylene/ethylene, the basic building blocks of plastics, use naphtha as a feedstock. Naphtha pricing tracks global oil prices closely, meaning that in the high oil price world of 2012 through the first half of 2014, naphtha was at a disadvantage to ethane as a feedstock. The oil price decline has narrowed the spread between ethane and naphtha, potentially reducing the economic attractiveness of the multiple new “world scale” ethane crackers currently under construction in the U.S. However, the long term fundamentals of a growing ethane supply remain intact, and exports and/or new domestic crackers are needed to balance supply and demand.

**NGL Pipeline System and Exports.** To reduce the NGL glut in regions such as the Appalachian Basin, major new NGL pipelines are on line or under construction, such as the Enterprise ATEX ethane pipeline, to transport NGLs to processing and export hubs on the Gulf Coast (Figure 1-7). Ethane shipments to Canada from PADD 2, to be used by Canadian petrochemical facilities, have also commenced on newly built pipelines. The Mariner East project, which Sunoco is currently considering expanding, transports NGLs from the Marcellus Shale to the Marcus Hook export terminal on the East Coast. Companies like Ineos have contracted for the shipment of ethane from Marcus Hook for use at their ethane cracking facilities in Europe.
Much of the domestic NGL storage, processing, and export infrastructure is located on the Texas Gulf Coast (Figure 1-8). In response to increasing domestic NGL supplies and in anticipation of the widening of the Panama Canal in 2016, which will allow for the transit of the largest NGL product ships to and from Asia, many NGL export terminals on the Gulf Coast are undergoing expansions, such as Enterprise’s Houston Ship Channel and Targa Resource’s Galena Park Marine Terminal. Also, a new LPG export terminal with initial export capacity of 4.4 million barrels per month is currently under construction in Freeport, TX, and is due on-line in the second half of 2016.
In ARI’s proprietary NGL data base, we carry over 100 billion barrels of remaining technically recoverable NGL resource, providing a robust resource base for continued NGL production growth under the right price and demand conditions. Implicitly affirming the sustainability and growth potential of domestic NGL supply are the multitude of new petrochemical facilities being constructed in the U.S. to capitalize on the NGL production resultant from shale gas and “tight oil” development.

Additional work is required to build upon this preliminary review of the current status of domestic NGL supply, demand and exports to provide a longer outlook for this important hydrocarbon product for years 2015-2025.

3. Market Potential for Ship-Based Transportation of CO₂ for Use by the U.S. EOR Industry

Historical Growth in EOR Production and the Associated Demand for CO₂. The U.S. has an active and growing CO₂ enhanced oil recovery (CO₂-EOR) industry, built on proven technology and several decades of successful application. The first commercial CO₂ flood began in 1972 at the SACROC Unit of the Kelly-Snyder oil field in the Permian Basin of West Texas. This CO₂ flood continues to operate successfully and, with recent investments, currently provides nearly 30,000 barrels per day of crude oil production. In the 1980s, a number of additional field-scale CO₂ floods were launched in major Permian Basin oil fields, such as Seminole, Slaughter and Wasson, establishing the commercial viability of CO₂-EOR.
Today there are 136 distinct CO₂-EOR projects underway in the U.S., facilitating about 300,000 barrels per day of crude oil production from a diversity of geological and geographic settings, Figure 1-9.

Figure 1-9. CO₂-EOR Projects and CO₂ Sources (2014)

In addition to providing important volumes of domestic oil production, the application of CO₂-EOR in domestic oil fields provides opportunities for secure, long-term storage of CO₂, as well as revenues to the CO₂ capture facilities from the sale and use of industrial CO₂ by the enhanced oil recovery industry.

CO₂-EOR based oil production has grown steadily in the past ten years, supported by the availability of both natural and industrial CO₂ supplies, Figure 1-10. The figure shows that while CO₂-EOR production in the Permian Basin has plateaued, due to limits on readily available CO₂ supplies, it has increased in the Mid-Continent and Gulf Coast, where additional natural and industrial supplies of CO₂ have been developed.
Today, the much higher oil production potential from CO₂-EOR in the various U.S. oil basins is limited by the lack of sufficient supplies of affordable CO₂. In addition, as the existing natural sources of CO₂ for EOR become depleted (such as the McElmo Dome, Colorado and Jackson Dome, Mississippi natural CO₂ deposits), the enhanced oil recovery industry will need to rely increasingly on anthropogenic CO₂ supplies captured from industrial and power plants if it is to achieve its underlying potential. Ship-based imports of CO₂ would help fill the CO₂ supply gap.

**Future Growth Potential for CO₂ for EOR.** Overall, the U.S. has recovered or proven a little over a third, 210 billion barrels, of its 624 billion barrels of original oil in-place endowment by using primary and secondary methods. As such, 414 billion barrels of oil have been “left behind”, providing an attractive target for enhanced (tertiary) oil recovery methods, particularly the use of miscible and immiscible CO₂ injection.

The distribution of the “left behind” oil in-place and the portion of this oil in-place that is technically favorable for CO₂-EOR is shown in Figure 1-11 for eight composite market regions of the country. With over 100 billion barrels of “left behind” oil technically favorable for CO₂-EOR, Figure 1-11 illustrates the importance of the Gulf Coast region (GOM offshore, Southeast and East/Central Texas) as the prime market area for delivery of new supplies of CO₂ for enhanced oil recovery.
In addition to the oil “left behind” after primary and secondary recovery in the main pay portion of an oil reservoir (above the reservoir’s water-oil contact), a large remaining oil target often exists in the lower portion of an oil reservoir (below the reservoir’s water-oil contact) called the residual oil zone (ROZ).

Advanced Resources has documented the presence of an additional 112 billion barrels of residual oil in-place in the San Andres Formation’s ROZ “fairways” in a four-county area of the Permian Basin, West Texas. A significant portion of this ROZ resource, equal to 77 billion barrels of oil in-place, is in “higher quality” reservoir settings (porosity greater than 8% and remaining oil saturation greater than 25%). Reservoir modeling by Advanced Resources shows that 27 billion barrels of the ROZ oil in-place is technically recoverable using miscible CO₂-EOR, with the “higher quality” portions of this resource offering promise for commercial viability.

Recent work by Melzer and Trentham has identified a series of San Andres Formation residual oil zone (ROZ) “fairways” in the Permian Basin that have been created by nature’s waterflooding of these oil reservoirs below their main pay zone, Figure 1-12.
Figure 1-12. San Andres ROZ “Fairways of the Permian Basin

In addition to providing potential for additional production of domestic oil, the San Andres ROZ “fairway” resource also offers an additional geologically favorable setting for storing CO₂. More recent work on the San Andres ROZ “fairway” resource of the Permian Basin, involving a detailed log- and core-based assessment by Advanced Resources, the University of Texas Permian Basin and Melzer Consulting identified another 79 billion barrels of residual oil in-place in an eight-county San Andres ROZ “fairway” area south of the original four-county area. While the calculation of technical recoverability of this second large ROZ oil in-place resource has yet to be performed, the eight-county ROZ study did establish that 58 billion barrels of the larger 79 billion barrels of San Andres ROZ “fairway” oil in-place in this eight-county area was in “higher quality” reservoir settings (porosity greater than 8% and remaining oil saturation greater than 25%).

**Economic Viability of CO₂-EOR under Low Oil Prices.** The recent decline in the price of oil has led some analysts to question the economic viability of CO₂-EOR at a time of lower oil prices. While many of the past studies of the economics of CO₂-EOR have been conducted using oil prices of $75 to $90 per barrel, a look at industry’s cost data shows that the application of CO₂-EOR in higher quality oil fields can be economically viable at oil prices of $50 to $60 per barrel.

For example, as shown in Figure 1-13, Occidental Petroleum, the most active and largest CO₂-EOR operator in the U.S., with an extensive number of CO₂-EOR projects in the Permian Basin, shows that Permian CO₂-EOR projects can generate significant net operating revenues at a $55 per barrel (WTI) oil price. Included in the cost structure is an allocation of $4.70/B for the CO₂ injectant, $4.00/B for production taxes, $4.70/B for power and energy and $16.80 for other CO₂-EOR costs.
Figure 1-13. Typical Costs for a Permian Basin CO₂-EOR Project at Current Oil Prices

Source: Oxy Petroleum, 2015

Note that the above cost structure does not include the initial capital costs for wells and other facilities or a return on investment. However, a $25/B net operating margin (oil price of $55/B less CO₂ costs of $30/B) provides considerable potential for covering capital investment plus a reasonable return on investment, particularly when a CO₂ flood is initiated in a field setting with already existing, usable water injection and oil production wells.

To further illustrate that CO₂-EOR can be economically viable at lower oil prices, Occidental Petroleum shows that CO₂-EOR can remain cash flow positive with a net operating margin of $13/B even at a much lower oil price of $35 per barrel (West Texas Intermediate, WTI). This is because a number of the costs of conducting a CO₂-EOR project, such as the power/energy and CO₂ supply costs, decline as oil prices decline, as illustrated on Figure 1-14.
Similar economic performance can be demonstrated to be expected for Gulf Coast CO₂-EOR projects.

Our analysis shows that CO₂-EOR is a lower cost, more economically viable option than many of the new sources of North American oil production, such as Canadian oil sands, non-core tight oil plays, exploration for conventional on-shore oil fields and pursuit of moderate-size, deep water Gulf of Mexico offshore oil fields.

Last year, the CO₂-EOR industry purchased and injected a total of 3.5 billion cubic feet per day (Bcfd) (plus recycled CO₂) to produce 300,000 barrels of oil per day of enhanced production. Approximately 80% of the purchased CO₂ volume (2.8 Bcfd) was from naturally occurring CO₂, captured from geologic sources located in Colorado, New Mexico, and Mississippi. However, the volumes of these naturally occurring sources of CO₂ are limited and industry data shows that natural CO₂ supplies are set to decline.
Need for New Sources of CO₂ Supplies. As new CO₂-EOR projects, such as Conroe in East Texas and North Hobbs in the Permian Basin, are launched and CO₂-EOR technology improves, enabling more oil fields to become economically viable for CO₂-EOR, the CO₂ market for EOR will increase considerably. With declining volumes of naturally occurring CO₂, the increased demand will need to be met by CO₂ supplies captured from industrial sources.

The availability of secure, affordable supplies of industrial CO₂ could help launch a new round of growth for CO₂–EOR supported by: (1) ship-bound transport of imported industrial CO₂ directed to high potential domestic oil fields, and (2) the distribution of this CO₂ to oil fields using a series of large-volume CO₂ pipelines, or “trunklines”.

As evidence of the potential for combining captured industrial CO₂ and storage of CO₂ with EOR, all of the active and planned North American CO₂ capture projects at coal-fired power plants will sell their captured CO₂ to oil fields for productive use by enhanced oil recovery with subsequent storage of the purchased CO₂. Moreover, the market for CO₂ by the EOR industry becoming considerably more robust as EOR technology improves. Key technologies -- such as conformance control, targeting unswept portions of oil fields with horizontal wells and adding mobility control to the injected CO₂ -- would make more oil fields economically viable for CO₂-EOR, would more than double the potential oil recovery from CO₂-EOR, and would substantially increase the market demand for CO₂ by the EOR industry.

Finally, a safe, reliable, regionally extensive network of CO₂ transportation pipelines is already in place in more than a dozen U.S. states plus Saskatchewan, Canada. This system is an essential building block for linking the ship-based transportation of CO₂ with its productive use and storage in oil fields with CO₂ enhanced oil recovery. The current CO₂ pipeline system consists of 50 individual CO₂ pipelines with a combined length of 4,765 miles. While the bulk of the existing large-volume CO₂ pipelines connect natural sources of CO₂ (e.g., Bravo Dome, New Mexico) with CO₂-EOR projects in large oil fields (e.g., Wasson, West Texas), numerous additional CO₂ pipeline exist that connect point sources of industrial CO₂ with CO₂-EOR projects in nearby oil fields.

Of the 3.5 billion cubic feet (Bcf) per day (68 million metric tons per year [MMT]) of CO₂ transported, 0.7 Bcf per day (14 MMT per year) is currently from industrial sources, including gas processing plants. With new industrial CO₂ capture facilities coming on line (e.g., Air Products PCS Nitrogen plant in southern Louisiana, Southern Company’s integrated gasification combined
cycle (IGCC) plant in Kemper County, Mississippi, etc.) – including over 600 miles of new pipeline – the volume of industrial CO₂ captured and transported is expected to increase substantially.

One example of providing CO₂ from industrial sources to EOR fields is the recently constructed 740 mile Gulf Coast CO₂ pipeline network is owned and operated by Denbury Onshore LLC, Figure 1-15. Two main pipelines comprise the pipeline network, the North East Jackson Dome (NEJD) Pipeline and the Green Pipeline. These two pipelines connect the natural CO₂ source in Jackson Dome, Central Mississippi, as well as new industrial sources to Denbury’s CO₂-EOR projects in Mississippi, Louisiana, and East Texas.

**Figure 1-15. Southeast Gulf Coast CO₂ Pipeline Infrastructure**

![Figure 1-15. Southeast Gulf Coast CO₂ Pipeline Infrastructure](image)

Source: Denbury Resources, 2015.

**Regulatory Framework for CO₂-EOR.** Oil production with CO₂-EOR is a well-established technology in the U.S. Thus, regulatory barriers for producing oil from CO₂-EOR in the U.S. are minimal. For fields currently being developed and produced using CO₂-EOR, it is possible that some may eventually be converted to geologic settings used for permanent geologic storage of CO₂. EPA has promulgated requirements for geologic storage of CO₂, including the establishment of a new class of wells, Class VI. Recent guidance issued by EPA confirms that CO₂-EOR operations can, in fact, result in stored CO₂, and a conversion to Class VI is not a requirement for assuring storage.
EPA has also established greenhouse gas reporting requirements under the Greenhouse Gas Reporting Program (GHGRP) for facilities that inject CO₂ underground for geologic storage and for all other facilities that inject CO₂ underground.

Nonetheless, regulatory barriers remain if credit for the CO₂ stored in the association with CO₂-EOR is sought. For example, under EPA “Clean Power Plan,” CO₂ storage with CO₂-EOR is recognized as a potential compliance mechanism. If CO₂ storage is verified under Subpart RR of the GHGRP, many are concerned that Subpart RR fundamentally conflicts with state-level mineral property and resource conservation law. Most significant concerns under Subpart RR include: (1) processes for and timeliness of EPA approval of monitoring, reporting, and verification (MRV) plans for CO₂-EOR projects, (2) what constitutes “new” activity in a CO₂-EOR project necessitating submittal of a new MRV plan, (3) how federal requirement relate to current state CO₂-EOR/Class II permitting processes, and (4) the extent to which MRV plans are subject to public litigation procedures.

4. Likely Legal and Regulatory Issues Associated with the Maritime Shipment of CO₂ for Use in EOR

The transportation and import (as well as export) of liquefied gas into the U.S. is well established with the development of the LNG industry. In addition, the precedent for trans-boundary movement of CO₂ has been established with the transportation of CO₂ from the U.S. (Dakota Gasification Facility) to Canada (Weyburn Oil Field) for use by CO₂-EOR.

A preliminary “issue spotting” review of potential legal and regulatory issues associated with the maritime transportation of commodity quantities of CO₂ was performed which focused on the transport: (1) between and among the United Gulf Coast, the United States California Coast, northwest Europe, China, Japan and South Korea; and (2) for purposes of use in CO₂-EOR, CO₂-EOR with associated storage, and potentially deep saline sequestration. Likely shipping routes considered included: (1) northwest Europe to the United States; and (2) Far East to Indonesia or California on backhaul of LPG/ethane carriers. This review is included as an Appendix.

Given the technical similarities between liquefied CO₂ and other materials being transported in bulk (e.g., LPG, LNG), analogies may be drawn that provide regulators and policymakers with comfort that the bulk maritime transport of CO₂ is environmentally sound. Nonetheless, the contemplated commercial activities are novel and thus may raise numerous complex, time-consuming, and unanticipated legal and regulatory hurdles, not all of which may
be surmountable. Project proponents may have to convince regulators and policymakers in the relevant jurisdictions that these activities can and should proceed.

While this initial review concludes that international and domestic laws and regulations do not explicitly prohibit or constrain CO₂ backhaul in LPG-class carriers, clear answers may nonetheless be required regarding how the contemplated commercial activities may be authorized, permitted, or otherwise allowed.

Thus, while certain precedents exist for importing liquefied gases into the U.S. and for trans-border movement of CO₂, potential legal and regulatory issues that may need to be addressed exist; thus, further examination of these issues is warranted.
Chapter 2 - Feasibility Study of Ship-Based Transportation of CO₂

Chapter 2

Market Potential for Ship-Based Transportation of CO₂ for Use by the U.S. Enhanced Oil Recovery Industry Phase I Report

Prepared by:
Advanced Resources International, Inc.
Market Potential for Ship-Based Transportation of CO₂ for Use by the U.S. Enhanced Oil Recovery Industry

Phase I Report

Prepared by:
Vello A. Kuuskraa, President
Matthew Wallace
Michael Godec
Advanced Resources International, Inc.
Arlington, VA
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Market Potential for Ship-Based Transportation of CO₂ for Use by the U.S. Enhanced Oil Recovery Industry

Background

The U.S. has an active and growing CO₂ enhanced oil recovery (CO₂-EOR) industry, is built on proven technology and several decades of successful application. The first commercial CO₂ flood began in 1972 at the SACROC Unit of the Kelly-Snyder oil field in the Permian Basin of West Texas. This CO₂ flood continues to operate successfully and, with recent investments, currently provides nearly 30,000 barrels per day of crude oil production. In the 1980s, a number of additional field-scale CO₂ floods were launched in major Permian Basin oil fields, such as Seminole, Slaughter and Wasson, establishing the commercial viability of CO₂-EOR.

Today there are 136 distinct CO₂-EOR projects underway in the U.S., providing about 300,000 barrels per day of crude oil production from a diversity of geological and geographic settings, Figure 1.

Figure 1. CO₂-EOR Projects and CO₂ Sources (2014)
Table 1 provides a tabulation of the 127 currently active miscible CO₂-EOR projects including their operator, oil field and pay zone, start date, project area and oil production in 2014. Table 2 provides similar information on the nine currently active immiscible CO₂-EOR projects. (The data in Table 1 are based on the latest (April, 2014) Oil and Gas Journal's survey of enhanced oil recovery, prepared in partnership with Advanced Resources International and Melzer Consulting.)

In addition to providing important volumes of domestic oil production, the application of CO₂-EOR in domestic oil fields provides opportunities for secure, long-term storage of CO₂, as well as revenues to the CO₂ capture facilities from the sale and use of industrial CO₂ by the enhanced oil recovery industry.

CO₂-EOR based oil production has grown steadily in the past ten years, supported by the availability of both natural and industrial CO₂ supplies, Figure 2. The figure shows that while CO₂-EOR production in the Permian Basin has plateaued, due to limits on readily available CO₂ supplies, it has increased in the Mid-Continent and Gulf Coast, where additional natural and industrial supplies of CO₂ have been developed.

![Figure 2. Growth of CO₂-EOR Production](image-url)
# Table 1. Currently Active Miscible CO₂-EOR Projects

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Table 2. Currently Active Immiscible CO2-EOR Projects

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Today, the much higher oil production potential from CO2-EOR in the various U.S. oil basins is limited by the lack of sufficient supplies of affordable CO2. In addition, as the existing natural sources of CO2 for EOR become depleted (such as the McElmo Dome, Colorado and Jackson Dome, Mississippi natural CO2 deposits), the enhanced oil recovery industry will need to rely increasingly on anthropogenic CO2 supplies captured from industrial and power plants if it is to achieve its underlying potential. Ship-based imports of CO2 would help fill the CO2 supply gap.

This report addresses six important topics that help define and establish the economic viability, market demand and pipeline infrastructure improvements for ship-based transportation of CO2 for use by the domestic CO2-EOR industry:

1. Fundamentals of the CO2-EOR Process,
2. Size of the CO2-EOR Target Resource,
3. Economic Viability of CO2-EOR,
4. Markets for Industrial CO2 Supplies,
5. CO2 Pipeline Infrastructure, and
1. **Fundamentals of the CO₂-EOR Process**

CO₂-EOR involves using deep wells to inject large volumes of CO₂ at high pressure, with or without alternating volumes of water, to improve (i.e., enhance) oil recovery, Figure 3. Under sufficient pressure, the injected CO₂ becomes miscible with the oil left behind in the reservoir after primary/secondary recovery, reducing the viscosity and the interfacial tension of the oil/CO₂ mixture while promoting its recovery in offset production wells.

**Figure 3. The Miscible CO₂-EOR Process**

Source: Advanced Resources International, 2015.

For most oil reservoirs, the development of miscibility between the reservoir’s oil and the injected CO₂ involves multiple contact between these two fluids. With extraction of the lighter components of the reservoir’s oil into the CO₂ phase and the solution of CO₂ into the oil phase, the two fluids to become essentially a single-phase fluid.
A critical value in the miscible CO$_2$–EOR process is the determination of the minimum miscibility pressure (MMP), the pressure at which sufficient in-situ mass transfer of components between the CO$_2$ and the reservoir’s oil occurs to achieve efficient oil recovery. The addition of an enrichment to the injected CO$_2$, using hydrocarbon components such as ethane, propane or butane, can lead to lower minimum miscibility pressures (MMP) helping extend the CO$_2$-EOR process to shallower and higher oil gravity reservoirs.

A CO$_2$ flood can also be operated at pressures below MMP, where the mechanisms of viscosity reduction, oil swelling and extraction of hydrocarbon components into the CO$_2$ phase help promote oil recovery. Recent laboratory work also suggests that relatively efficient oil recovery can be achieved at pressures (in the reservoir) near (but still below) MMP, although further field-scale verification of the efficiency of the near-miscible CO$_2$-EOR process is still required.

2. **Size of the CO$_2$-EOR Target Resource**

Primary oil recovery (typically pressure depletion) and secondary oil recovery (typically water flooding) recover 25% to 45% of the original oil in-place in an oil reservoir, leaving behind a large volume of “left behind” oil.

Overall, the U.S. has recovered or proven a little over a third, 210 billion barrels, of its 624 billion barrels of original oil in-place endowment by using primary and secondary methods, Figure 4. As such, 414 billion barrels of oil have been “left behind”, providing an attractive target for enhanced (tertiary) oil recovery methods, particularly the use of miscible and immiscible CO$_2$ injection.

A more rigorous examination of the characteristics and geologic settings of the 414 billion barrels of “left behind” oil indicate that 284 billion barrels is in oil fields and reservoirs technically feasible for using CO$_2$ as the enhanced oil recovery process. Excluded from the 414 billion barrel “left behind” oil volume are shallow as well as heavy oil fields that are not suitable for miscible or near-miscible oil recovery using CO$_2$. The distribution of the “left behind” oil in-place and the portion of this oil in-place that is technically favorable for CO$_2$-EOR is shown in Figure 5 for eight composite market regions of the country. With over 100 billion barrels of “left behind” oil technically favorable for CO$_2$-EOR, Figure 5 illustrates the importance of the Gulf Coast region (GOM offshore, Southeast and East/Central Texas) as the prime market area for delivery of new supplies of CO$_2$ for enhanced oil recovery.
Figure 4. Domestic Conventional* Oil Endowment and Target Resource for EOR

Original Oil In-Place: 624 B Barrels
Remaining Oil In-Place: 414 B Barrels
Target for EOR 414 Billion Barrels
Cumulative Production 190 Billion Barrels
Proved Reserves 20 Billion Barrels

*Does not include “tight” oil production or reserves.
Source: Advanced Resources International analyses, 2015.

Figure 5. Regional Distribution of the Target Resource for CO2-EOR

Source: Advanced Resources International, 2015.
In addition to the oil “left behind” after primary and secondary recovery in the main pay portion of an oil reservoir (above the reservoir’s water-oil contact), a large remaining oil target often exists in the lower portion of an oil reservoir (below the reservoir’s water-oil contact) called the residual oil zone (ROZ).

Recent work by Melzer and Trentham has identified a series of San Andres Formation residual oil zone (ROZ) “fairways” in the Permian Basin that have been created by nature’s waterflooding of these oil reservoirs below their main pay zone, Figure 6.

Figure 6. San Andres ROZ “Fairways of the Permian Basin

Advanced Resources has documented the presence of 112 billion barrels of residual oil in-place in the San Andres Formation’s ROZ “fairways” in a four-county area of the Permian Basin, West Texas, Table 3. A significant portion of this ROZ resource, equal to 77 billion barrels of oil in-place, is in “higher quality” reservoir settings (porosity greater than 8% and remaining oil saturation greater than 25%). Reservoir modeling by Advanced Resources shows that 27 billion barrels of the ROZ oil in-place is technically recoverable using miscible CO₂-EOR, with the “higher quality” portions of this resource offering promise for commercial viability.

### Table 3. San Andres ROZ “Fairway” Resources: Four County Area of Permian Basin, West Texas

<table>
<thead>
<tr>
<th>County</th>
<th>Total Oil In-Place (B Bbls)</th>
<th>Quality of Oil In-Place (B Bbls)</th>
<th>Technically Recoverable (B Bbls)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>&quot;Higher&quot;</td>
<td>&quot;Lower&quot;</td>
</tr>
<tr>
<td>Gaines</td>
<td>45.5</td>
<td>35.4</td>
<td>10.1</td>
</tr>
<tr>
<td>Yoakum</td>
<td>20.7</td>
<td>16.1</td>
<td>4.6</td>
</tr>
<tr>
<td>Terry</td>
<td>17.9</td>
<td>10.6</td>
<td>7.3</td>
</tr>
<tr>
<td>Dawson</td>
<td>27.8</td>
<td>14.6</td>
<td>13.2</td>
</tr>
<tr>
<td>Total</td>
<td>111.9</td>
<td>76.7</td>
<td>35.2</td>
</tr>
</tbody>
</table>

Source: Advanced Resources International, 2015.

In addition to providing potential for additional production of domestic oil, the San Andres ROZ “fairway” resource also offers an additional geologically favorable setting for storing CO₂.

More recent work on the San Andres ROZ “fairway” resource of the Permian Basin, involving a detailed log- and core-based assessment by Advanced Resources, the University of Texas Permian Basin and Melzer Consulting identified 79 billion barrels of residual oil in-place in an eight-county San Andres ROZ “fairway” area south of the original four-county area. While the calculation of technical recoverability of this second large ROZ oil in-place resource has yet to be performed, the eight-county ROZ study did establish that 58 billion barrels of the larger 79 billion barrels of San Andres ROZ “fairway” oil in-place in this eight-county area was in “higher quality” reservoir settings (porosity greater than 8% and remaining oil saturation greater than 25%).
Table 4. San Andres ROZ “Fairway” Resources:  Eight County Area of Permian Basin, West Texas

<table>
<thead>
<tr>
<th>County</th>
<th>Total Oil In-Place (B Bbls)</th>
<th>Quality of Oil In-Place (B Bbls)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>&quot;Higher&quot;</td>
</tr>
<tr>
<td>Andrews</td>
<td>37.1</td>
<td>31.2</td>
</tr>
<tr>
<td>Ector</td>
<td>7.0</td>
<td>5.5</td>
</tr>
<tr>
<td>Martin</td>
<td>6.7</td>
<td>4.8</td>
</tr>
<tr>
<td>Winkler</td>
<td>9.5</td>
<td>8.0</td>
</tr>
<tr>
<td>Crane</td>
<td>7.4</td>
<td>4.3</td>
</tr>
<tr>
<td>Upton</td>
<td>3.3</td>
<td>-</td>
</tr>
<tr>
<td>Ward</td>
<td>8.3</td>
<td>4.1</td>
</tr>
<tr>
<td>Midland</td>
<td>*</td>
<td>*</td>
</tr>
<tr>
<td>Total</td>
<td>79.3</td>
<td>57.9</td>
</tr>
</tbody>
</table>

*The ROZ “fairway” resource in Midland County is in the Grayburg Fm.  
Source: Advanced Resources International, 2015.

3. Economic Viability of CO2-EOR

The recent decline in the price of oil has led some analysts to question the economic viability of CO2 enhanced oil recovery at a time of lower oil prices.  While many of the past studies of the economics of CO2-EOR have been conducted using oil prices of $75 to $90 per barrel, a look at industry’s cost data shows that the application of CO2-EOR in higher quality oil fields can be economically viable at oil prices of $50 to $60 per barrel.

Perman Basin Examples

For example, as shown in Figure 7, Occidental Petroleum, the most active and largest CO2-EOR operator in the U.S., with an extensive number of CO2-EOR projects in the Perman Basin, shows that Perman CO2-EOR projects can generate significant net operating revenues at a $55 per barrel (WTI) oil price.  Included in the cost structure is an allocation of $4.70/B for the CO2 injectant, $4.00/B for production taxes, $4.70/B for power and energy and $16.80 for other CO2-EOR costs.
Figure 7. Typical Costs for a Permian Basin CO2-EOR Project at Current Oil Prices

Source: Oxy Petroleum, 2015

Note that the above cost structure does not include the initial capital costs for wells and other facilities or a return on investment. However, a $25/B net operating margin (oil price of $55/B less CO2 costs of $30/B) provides considerable potential for covering capital investment plus a reasonable return on investment, particularly when a CO2 flood is initiated in a field setting with already existing, usable water injection and oil production wells.

To further illustrate that CO2-EOR can be economically viable at lower oil prices, Occidental Petroleum shows that CO2-EOR can remain cash flow positive with a net operating margin of $13/B even at a much lower oil price of $35 per barrel (West Texas Intermediate, WTI). This is because a number of the costs of conducting a CO2-EOR project, such as the power/energy and CO2 supply costs, decline as oil prices decline, as illustrated on Figure 8. This important cost/oil price relationship topic is further developed below.
The information from the two CO\textsubscript{2}-EOR project examples, in Figures 7 and 8, shows that a reduction in the oil price of $20/B is compensated by a reduction in CO\textsubscript{2}-EOR operating costs of $8/B (consisting of $2.50/B for energy, $1.70/B for taxes and SG&A, $3.30/B for well and surface maintenance, and $0.70/B for the cost of CO\textsubscript{2} supply). For projects with a typical royalty of 20%, a $20/B drop in the oil price reduces the royalty payment (in dollars or share of production) by $4/B. As such, a $20/B decline in oil prices, from $55 per barrel to $35 per barrel, is compensated by a reduction in costs (including royalty payments) of about $12/B.

**Gulf Coast Example**

To further examine the economic viability of CO\textsubscript{2}-EOR, we have tabulated the CO\textsubscript{2}-EOR operating costs for Denbury Resources. This tabulation shows that a typical Gulf Coast CO\textsubscript{2}-EOR project in the Gulf Coast provides a net operating margin of nearly $35/B, based on actual incurred costs of $21.40/B during the first half of 2015, and an oil price of $57/B, including a two dollar premium over WTI for light oil available in the Gulf Coast, Table 5.
Our analysis shows that CO₂-EOR is a lower cost, more economically viable option than many of the new sources of North American oil production, such as Canadian oil sands, non-core tight oil plays, exploration for conventional on-shore oil fields and pursuit of moderate-size, deep water Gulf of Mexico offshore oil fields.

As part of our more rigorous Phase II investigation of the “Market Potential for Ship-based Transportation of CO₂ for Use by U.S. Enhanced Oil Recovery Industry”, we will take a more in-depth look at the economic viability of CO₂-EOR under alternative outlooks for oil prices and costs for CO₂ supplies, including greater characterization of any regional- and/or resource-specific variability in the economic viability of CO₂-EOR

4. Markets for Industrial CO₂ Supplies

Last year, the CO₂-EOR industry purchased and injected a total of 3.5 billion cubic feet per day (Bcfd) (plus recycled CO₂) to produce 300,000 barrels of oil per day of enhanced production. Approximately 80% of the purchased CO₂ volume (2.8 Bcfd) was from naturally occurring CO₂, captured from geologic sources located in Colorado, New Mexico, and Mississippi. However, the volumes of these naturally occurring sources of CO₂ are limited and industry data shows that natural CO₂ supplies are set to decline.

### Table 5. Typical Operating Costs for a Gulf Coast CO₂-EOR Projects

<table>
<thead>
<tr>
<th>CO₂-EOR Operating Cost Items</th>
<th>Correlation w/Oil Prices</th>
<th>1st Half 2015 Costs ($/B)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 CO₂ Supply</td>
<td>Direct</td>
<td>$5.00</td>
</tr>
<tr>
<td>2 Power and Fuel</td>
<td>High</td>
<td>$6.80</td>
</tr>
<tr>
<td>3 Labor and Overhead</td>
<td>None</td>
<td>$5.00</td>
</tr>
<tr>
<td>4 Repairs/Mnt/Workovers</td>
<td>Partial</td>
<td>$3.00</td>
</tr>
<tr>
<td>5 Other (Chemicals, etc.)</td>
<td>Partial</td>
<td>$1.60</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>$21.40</strong></td>
</tr>
</tbody>
</table>

Source: Denbury Resources Investor Presentation, November 2015.
As new CO₂-EOR projects, such as Conroe in East Texas and North Hobbs in the Permian Basin, are launched and CO₂-EOR technology improves enabling more oil fields to become economically viable for CO₂-EOR, the CO₂ market for EOR will increase considerably. With declining volumes of naturally occurring CO₂, the increased demand will need to be met by CO₂ supplies captured from industrial sources.

The availability of secure, affordable supplies of industrial CO₂ would help launch a new round of growth for CO₂–EOR supported by: (1) ship-bound transport of imported industrial CO₂ directed to high potential domestic oil fields and (2) the distribution of this CO₂ to oil fields using a series of large-volume CO₂ pipelines.

In this Phase I report, we discuss the near-term market for CO₂ supplies for four key regions - - the Gulf Coast, Mid-Continent, West Coast, and Offshore Gulf of Mexico. For these four regions, the Phase I report identifies the current demand for CO₂ in each region and the expected need for CO₂ supplies captured from industrial sources. A more in-depth evaluation of the projected demand for CO₂ by region will be provided in the Phase II portion of this study.

**Gulf Coast CO₂ Market**

The Gulf Coast CO₂-EOR market, consisting of East and South Texas, Louisiana, Mississippi, Alabama and Florida, is the location of a large number of mature light oil fields with reservoir properties favorable for CO₂-EOR, including large oil fields such as Conroe, Citronelle, and Hackberry West.

Significant numbers of CO₂-EOR projects have already been launched in the Gulf Coast region. Table 6 tabulates the 20 CO₂-EOR projects that are already operating in the Gulf Coast Region at 17 oil fields. In 2014, these 20 projects utilized a little over 1 Bcf of CO₂ to produce nearly 50,000 barrels per day of additional oil.

The current one Bcf of CO₂ supply for EOR in the Gulf Coast region is primarily natural CO₂ from Jackson Dome in Mississippi. However, this CO₂ volume also includes two new industrial sources of CO₂ - - from the Air Products hydrogen and the PCS nitrogen plants in Louisiana - - that recently came on-line and currently sell 75 million cubic feet per day (MMcfd) into Denbury’s Green CO₂ pipeline for use by (and storage in) CO₂-EOR projects in SE Texas.
Table 6. Gulf Coast CO₂-EOR Projects

<table>
<thead>
<tr>
<th>Operator</th>
<th>Field</th>
<th>Pay Zone</th>
<th>State</th>
<th>Start Date</th>
<th>Tot. Prod. (bbl/d)</th>
<th>Enh. Prod. (bbl/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denbury Resources</td>
<td>Delhi</td>
<td>Paluxy/Tuscaloosa</td>
<td>LA</td>
<td>11/1/09</td>
<td>5,920</td>
<td>5,920</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Lockhart Crossing</td>
<td>Wilcox</td>
<td>LA</td>
<td>12/07</td>
<td>1,140</td>
<td>1,140</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Brookhaven</td>
<td>Lower Tuscaloosa</td>
<td>MS</td>
<td>1/05</td>
<td>2,500</td>
<td>2,500</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Cranfield</td>
<td>Tuscaloosa</td>
<td>MS</td>
<td>07/08</td>
<td>1,460</td>
<td>1,460</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>East Mallalieu</td>
<td>Lower Tuscaloosa</td>
<td>MS</td>
<td>12/03</td>
<td>366</td>
<td>366</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>West Mallalieu</td>
<td>Lower Tuscaloosa</td>
<td>MS</td>
<td>1986</td>
<td>1,964</td>
<td>1,964</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Eucutta</td>
<td>Eutaw</td>
<td>MS</td>
<td>3/06</td>
<td>2,810</td>
<td>2,810</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Heidelberg, East</td>
<td>Eutaw</td>
<td>MS</td>
<td>6/11</td>
<td>1,196</td>
<td>1,196</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Heidelberg, West</td>
<td>Eutaw</td>
<td>MS</td>
<td>12/08</td>
<td>5,234</td>
<td>5,234</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Lazy Creek</td>
<td>Lower Tuscaloosa</td>
<td>MS</td>
<td>12/01</td>
<td>190</td>
<td>190</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Little Creek</td>
<td>Lower Tuscaloosa</td>
<td>MS</td>
<td>1985</td>
<td>760</td>
<td>760</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Martinville</td>
<td>Mooringsport</td>
<td>MS</td>
<td>3/06</td>
<td>165</td>
<td>165</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Martinville</td>
<td>Rodessa</td>
<td>MS</td>
<td>3/06</td>
<td>135</td>
<td>135</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Martinville</td>
<td>Wash-Fred 8500</td>
<td>MS</td>
<td>9/06</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>McComb</td>
<td>Lower Tuscaloosa</td>
<td>MS</td>
<td>11/03</td>
<td>1,580</td>
<td>1,580</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Soso</td>
<td>Rodessa 11,180</td>
<td>MS</td>
<td>9/06</td>
<td>1,990</td>
<td>1,990</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Soso</td>
<td>Bailey 11,701</td>
<td>MS</td>
<td>4/06</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Tinsley</td>
<td>Woodruff</td>
<td>MS</td>
<td>01/07</td>
<td>9,640</td>
<td>9,640</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>Oyster Bayou</td>
<td>Frio</td>
<td>TX</td>
<td>5/1/10</td>
<td>4,780</td>
<td>4,780</td>
</tr>
<tr>
<td>Denbury Resources</td>
<td>West Hastings</td>
<td>Frio</td>
<td>TX</td>
<td>12/1/10</td>
<td>5,720</td>
<td>5,720</td>
</tr>
</tbody>
</table>

Total Production (bbl/d) 47,900 47,900

Given the expected decline in natural CO₂ supply from Jackson Dome, Figure 9, the incremental CO₂ supply for EOR in the Gulf Coast will need to be from industrial sources or imports of ship-transported CO₂. Potential new CO₂ supply sources for this region include 50 MMcfd of CO₂ capture from chemical plants in Louisiana and 235 MMcfd of CO₂ capture from two new power plants, the Kemper County IGCC in Mississippi and the W.A. Parrish power plant in Thompsons, East Texas, expected on line in 2016 and 2017, respectively.

Even with the availability of new industrial and power plant sources of CO₂, considerable additional demand for CO₂ for use by EOR exists in this market area.
Mid-Continent CO\textsubscript{2} Market

The Mid-Continent CO\textsubscript{2}-EOR market consists of light oil fields in Oklahoma, Kansas, Nebraska, Arkansas, and the Texas Panhandle. This region contains a significant number of oil fields technically amenable to CO\textsubscript{2}-EOR, especially in Oklahoma and the Texas Panhandle, such as the large oil fields of Burbank, Oklahoma City, and Postle.

The Mid-Continent region contains nine active CO\textsubscript{2}-EOR projects, Table 7. Two of the nine CO\textsubscript{2}-EOR projects, NW Velma Hoxbar and Northeast Purdy have been in operation since the early 1980s. In total, these nine oil fields provided over 16,000 enhanced barrels of oil per day in 2014, utilizing 150 MMcf/d of purchased CO\textsubscript{2}, primarily from industrial sources.
Table 7. Mid-Continent CO\textsubscript{2}-EOR Projects

<table>
<thead>
<tr>
<th>Operator</th>
<th>Field</th>
<th>Pay Zone</th>
<th>State</th>
<th>Start Date</th>
<th>Tot. Prod. (bbl/d)</th>
<th>Enh. Prod (bbl/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chaparral Energy</td>
<td>Camrick</td>
<td>Morrow</td>
<td>OK</td>
<td>4/01</td>
<td>1,200</td>
<td>1,200</td>
</tr>
<tr>
<td>Chaparral Energy</td>
<td>North Perryon</td>
<td>Upper Morrow</td>
<td>OK</td>
<td>1/6</td>
<td>600</td>
<td>600</td>
</tr>
<tr>
<td>Chaparral Energy</td>
<td>Booker</td>
<td>Upper Morrow</td>
<td>TX</td>
<td>1/10</td>
<td>1,100</td>
<td>1,100</td>
</tr>
<tr>
<td>Chaparral Energy</td>
<td>Farnsworth</td>
<td>Upper Morrow</td>
<td>TX</td>
<td>3/10</td>
<td>2,280</td>
<td>2,180</td>
</tr>
<tr>
<td>Chaparral Energy</td>
<td>NW Velma Hoxbar</td>
<td>Sims</td>
<td>OK</td>
<td>9/82</td>
<td>310</td>
<td>260</td>
</tr>
<tr>
<td>Chaparral Energy</td>
<td>Burbank</td>
<td>Burbank</td>
<td>OK</td>
<td>4/13</td>
<td>2,160</td>
<td>1,000</td>
</tr>
<tr>
<td>Breitburn Energy</td>
<td>Postle</td>
<td>Morrow</td>
<td>OK</td>
<td>1/07-1/09</td>
<td>7,800</td>
<td>7,600</td>
</tr>
<tr>
<td>Merit Energy</td>
<td>Northeast Purdy</td>
<td>Springer</td>
<td>OK</td>
<td>9/82</td>
<td>1,800</td>
<td>1,800</td>
</tr>
<tr>
<td>Merit Energy</td>
<td>Bradley</td>
<td>Springer</td>
<td>OK</td>
<td>2/97</td>
<td>800</td>
<td>600</td>
</tr>
</tbody>
</table>

Total Production (bbl/d): 18,050 16,340

A portion of the CO\textsubscript{2} purchased for CO\textsubscript{2}-EOR in the Mid-Continent region, 35 MMcf/d is natural CO\textsubscript{2} from the Bravo Dome in northeastern New Mexico. The CO\textsubscript{2} from Bravo Dome is delivered to the Postle oil field, through the Transpetco CO\textsubscript{2} pipeline. Breitburn Energy, the current operator of Postle, intends to increase the CO\textsubscript{2} supply and expand the CO\textsubscript{2}-EOR operation in this oil field in the near future. Further development and expansion at other oil fields in the Mid-Continent, however, will need to rely on CO\textsubscript{2} supplies captured from other sources.

With regards to ship-based supplies of CO\textsubscript{2} for CO\textsubscript{2}-EOR, CO\textsubscript{2} pipeline infrastructure could be extended from existing CO\textsubscript{2} pipelines in the Gulf Coast to Central Oklahoma, the location of the majority of the oil fields technically viable for CO\textsubscript{2}-EOR in this region. The Phase II report will provide an in-depth look at the demand for ship-based CO\textsubscript{2} for use by oil fields in the Mid-Continent region.

**West Coast CO\textsubscript{2} Market**

The potential West Coast CO\textsubscript{2} market is primarily in central and southern California, in the Los Angeles, San Joaquin and Ventura basins. A large number of technically favorable for CO\textsubscript{2}-EOR oil fields exist in these three basins, including large oil fields such as Elk Hills, Santa Fe and Ventura.
With the recent decision by the U.S. Department of Energy to suspend financial support to the $4 billion Hydrogen Energy California (HECA) clean coal project in western Kern County that had plans to capture and sell CO₂ to California oil fields, there is currently no readily available CO₂ available for the West Coast market. (A requirement to capture CO₂ from the refinery complexes in Southern California may provide some CO₂ supplies in the future, although there are no currently announced plans to such an activity.)

A longer-term market for CO₂ landed on the West Coast could be the oil fields of the Permian Basin, although a large-scale, long distance CO₂ pipeline would need to be installed to transport the CO₂ from a West Coast port to the Permian Basin of New Mexico and West Texas. A CO₂ pipeline connecting the West Coast port to the entry point of the planned Lobos Pipeline on the border of Arizona and New Mexico would provide a moderate distance transport option for delivering CO₂ from the West Coast to the Permian Basin. While the Lobos Pipeline project is currently on hold, the expansion of Permian Basin CO₂-EOR operations, supported by a more favorable outlook for oil prices could make both the Lobos CO₂ pipeline and its connection to the West Coast port feasible.

*Offshore GOM CO₂ Market*

A large number of oil fields exist in the offshore of the Gulf of Mexico that are technically amenable to use of miscible CO₂-EOR technology. The residual oil in-place of offshore oil fields favorable for CO₂-EOR is approximately 29 billion barrels. As CO₂-EOR technology improves, particularly with the use of sub-sea technology, these oil fields will become candidates for CO₂-EOR development.

One of the primary costs of offshore CO₂-EOR is construction of sub-sea pipelines for delivery of CO₂ to oil fields. Ship-based CO₂ supplies could provide a more viable solution to this problem, eliminating the need for a new pipeline system to deliver land-based CO₂ supplies to offshore oil fields. CO₂ supply ships could offload their CO₂ directly to offshore oil fields, or deliver supplies to port-based CO₂ hubs for distribution offshore. This method of delivery reduces the infrastructure required by land-based CO₂-EOR supplies and will help overcome one of the major barriers to offshore CO₂-EOR development.
Industrial CO2 Capture Projects

As evidence of the potential for combining captured industrial CO2 and storage of CO2 with EOR, all of the active and planned North American CO2 capture projects at coal-fired power plants will sell their captured CO2 to oil fields for productive use by enhanced oil recovery with subsequent storage of the purchased CO2.

- The “poster child” of capture and productive use of CO2 for EOR is the 135 MMcfd of CO2 captured from the Dakota Coal Gasification Plant and shipped to the Weyburn oil field in Canada for CO2-EOR.

- The recently completed Boundary Dam project in Saskatchewan, Canada also sells its 60 MMcfd of post-combustion captured CO2 to the Weyburn CO2-EOR project.

- The previously mentioned Mississippi Power project in the Gulf Coast will capture 165 MMcfd of CO2 for CO2-EOR in Mississippi, Louisiana, and East Texas.

- The Petra Nova Project to develop a commercial-scale post-combustion capture project at Unit 8 of WA Parish generating station southwest of Houston, Texas, that will capture 90% of CO2 from flue gas slipstream providing 1.4 to 1.6 million metric tons per year of CO2 to be used for EOR in West Ranch Field 80 miles away.

Finally, our analysis shows that the market for CO2 by the EOR industry becoming considerably more robust as EOR technology improves. Key technologies - - such as conformance control, targeting unswept portions of oil fields with horizontal wells and adding mobility control to the injected CO2 - - would make more oil fields economically viable for CO2-EOR, would more than double the potential oil recovery from CO2-EOR, and would substantially increase the market demand for CO2 by the EOR industry.
5. CO₂ Pipeline Infrastructure

Background

A safe, reliable, regionally extensive network of CO₂ transportation pipelines is already in place in more than a dozen U.S. states plus Saskatchewan, Canada. This system is an essential building block for linking the ship-based transportation of CO₂ with its productive use and storage in oil fields with CO₂ enhanced oil recovery.

The current CO₂ pipeline system consists of 50 individual CO₂ pipelines with a combined length of 4,765 miles, Table 8. While the bulk of the existing large-volume CO₂ pipelines connect natural sources of CO₂ (e.g., Bravo Dome, New Mexico) with CO₂-EOR projects in large oil fields (e.g., Wasson, West Texas), numerous additional CO₂ pipeline exist that connect point sources of industrial CO₂ with CO₂-EOR projects in nearby oil fields.

<table>
<thead>
<tr>
<th>Region</th>
<th>Miles of CO₂ Pipeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permian Basin (W. TX, NM, S. CO)</td>
<td>2,600</td>
</tr>
<tr>
<td>Gulf Coast (MS, LA, E. TX)</td>
<td>740</td>
</tr>
<tr>
<td>Rocky Mountains (N. CO, WY, MT)</td>
<td>730</td>
</tr>
<tr>
<td>Mid-Continent (OK, KS)</td>
<td>480</td>
</tr>
<tr>
<td>Other (ND, MI, Canada)</td>
<td>215</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4,765</strong></td>
</tr>
</tbody>
</table>


Today’s CO₂ pipeline system had its beginnings in the 1970s, built for delivering CO₂ for use in the SACROC oil field in West Texas. This was followed by a series of large volume CO₂ pipelines connecting natural sources of CO₂ in Colorado and New Mexico with large oil fields in the Permian basin of West Texas and Eastern New Mexico. With the recent completion of two new long-distance CO₂ pipelines - - the Green Pipeline in Louisiana and Texas, and the Greencore Pipeline in Wyoming and Montana - - a much more geographically diverse CO₂ pipeline system is now in place. A variety of shorter and smaller volume laterals are being constructed to link these large-scale CO₂ pipelines to surrounding oil fields that are amenable to CO₂-EOR.
Of the 3.5 billion cubic feet (Bcf) per day (68 million metric tons per year [MMT]) of CO\textsubscript{2} transported, 0.7 Bcf per day (14 MMT per year) is from industrial sources, including gas processing plants. With new industrial CO\textsubscript{2} capture facilities coming on line (e.g., Air Products PCS Nitrogen plant in southern Louisiana, Southern Company’s integrated gasification combined cycle (IGCC) plant in Kemper County, Mississippi, etc.) – including over 600 miles of new pipeline – the volume of industrial CO\textsubscript{2} captured and transported is expected to increase substantially.

**Gulf Coast CO\textsubscript{2} Pipeline System**

The recently constructed 740 mile Gulf Coast CO\textsubscript{2} pipeline network is owned and operated by Denbury Onshore LLC, Figure 10. Two main pipelines comprise the pipeline network, the North East Jackson Dome (NEJD) Pipeline and the Green Pipeline. These two pipelines connect the natural CO\textsubscript{2} source in Jackson Dome, Central Mississippi, as well as new industrial sources to Denbury’s CO\textsubscript{2}-EOR projects in Mississippi, Louisiana, and East Texas.

**Figure 10. Southeast Gulf Coast CO\textsubscript{2} Pipeline Infrastructure**

Table 9 lists the CO\textsubscript{2} transportation pipelines currently installed in the Gulf Coast region that connect natural and industrial sources of CO\textsubscript{2} with oil fields along the Gulf Coast.
### Table 9. Gulf Coast CO₂ Transportation Pipelines

<table>
<thead>
<tr>
<th>Scale</th>
<th>Pipeline</th>
<th>Operator</th>
<th>Location</th>
<th>Length (mi)</th>
<th>Diameter (in)</th>
<th>Estimated Flow Capacity (MMcfd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Large-Scale Trunk-lines</td>
<td>Green Line</td>
<td>Denbury Resources</td>
<td>LA, TX</td>
<td>314</td>
<td>24</td>
<td>930</td>
</tr>
<tr>
<td></td>
<td>Delta</td>
<td>Denbury Resources</td>
<td>MS, LA</td>
<td>108</td>
<td>24</td>
<td>590</td>
</tr>
<tr>
<td></td>
<td>Northeast Jackson Dome (NEJD)</td>
<td>Denbury Resources</td>
<td>MS, LA</td>
<td>183</td>
<td>20</td>
<td>360</td>
</tr>
<tr>
<td>Distribution Line</td>
<td>Free State</td>
<td>Denbury Resources</td>
<td>MS</td>
<td>85</td>
<td>20</td>
<td>360</td>
</tr>
<tr>
<td></td>
<td>Sonat</td>
<td>Denbury Resources</td>
<td>MS</td>
<td>50</td>
<td>18</td>
<td>170</td>
</tr>
</tbody>
</table>

Source: Denbury Resources, 2015.

Denbury also has plans to build two significant CO₂ pipeline laterals from the Green Pipeline to oil fields in East Texas for launching additional CO₂-EOR projects in this region. Construction of the first pipeline, a 9-mile, 16-inch lateral from the Green Pipeline to the Webster oil field near Harris, Texas started in 2014, Figure 11. Delivery and injection of CO₂ is scheduled for 2016. The construction cost of this lateral is estimated at $23 million. The Webster CO₂-EOR project is expected to produce 15,000 barrels of oil per day.

**Figure 11. Planned Webster Oil Field CO₂ Lateral Pipeline**

Source: Denbury Resources, 2015
Construction of a second pipeline lateral, connecting the Conroe CO₂-EOR project to the Green Pipeline, is also expected, with permitting and route selection currently underway. This lateral is expected to extend roughly 90 miles from the Green Pipeline near the border of Texas and Louisiana to the Conroe oil field, Figure 12. Construction on the 20-inch pipeline is expected to begin in 2016, with first delivery and injection of CO₂ in 2017 and first oil production in 2018. The Conroe CO₂-EOR project is expected to yield a peak production of between 15,000 and 20,000 barrels of oil per day.

![Figure 12. Planned Conroe Oil Field CO₂ Lateral Pipeline](source)

In addition to the Denbury Resources CO₂ pipeline system, a new 82 mile, point-to-point CO₂ pipeline is being constructed to deliver CO₂ from the Petra Nova Carbon Capture project at W.A. Parish power plant in Thompsons, TX to a new CO₂-EOR project at the West Ranch oil field of the Gulf Coast of Texas, Figure 13. Approximately 70 MMcfd of CO₂ will be delivered to the oil field starting in 2016.
CO₂ Pipeline Costs

CO₂ pipeline development costs depend on a number of variables, including length, pipeline diameter, terrain, and other regional variations. Similar to oil field infrastructure development, capital costs for CO₂ pipelines are lowest in the Permian Basin. For example, the 216 mile, 16-inch Lobos Pipeline, with a capacity of 3,000 MMcf/d, was expected to cost approximately $300 million. Other announced CO₂ pipelines in the Gulf Coast and Rocky Mountain regions cost between 25 percent and 33 percent more per inch-mile than the Lobos Pipeline due to more challenging terrain and navigation through denser populations.

Pipeline transportation costs depend heavily on the volume of CO₂ being transported. Figure 14 shows that as the amount of CO₂ that is transported increases, there is a notable decrease in costs per ton of CO₂ delivered due to economies of scale.
In Phase II of the study, we will take a more detailed look at the CO₂ pipeline and transportation costs for linking CO₂ transported by ship to oil fields favorable for CO₂-EOR.

**Figure 14. Transportation Cost as Function of CO₂ Throughput**

![Graph showing transportation cost as function of CO₂ throughput.](image)


6. **Key Regulatory and Environmental Issues**

Oil production with CO₂-EOR is a well-established technology in the U.S. Thus, regulatory barriers for producing oil from CO₂-EOR in the U.S. are minimal. CO₂ injection wells for EOR are regulated as Class II wells under the U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) program.

For fields currently being developed and produced using CO₂-EOR, it is possible that some will eventually be converted to geologic settings used for permanent geologic storage of CO₂. EPA has promulgated requirements for geologic storage of CO₂, including the establishment of a new class of wells, Class VI, under the authority of the Safe Drinking Water Act’s (SDWA’s) UIC Program. These requirements, generally known as the Class VI rule and designed to protect underground sources of drinking water (USDWs), build upon existing UIC Program requirements.
The Class VI rule contains extensive, tailored requirements that address CO₂ injection for long-term storage to ensure that wells used for geologic storage are appropriately sited, constructed, tested, monitored, and closed. The rule is intended to provide owners and operators with the tools necessary to address CO₂ storage in various geologic settings, including oil and gas fields that are transitioned for use as CO₂ storage sites.

In December 2013, EPA published draft guidance on the conversion of Class II wells to Class VI wells, or, perhaps more appropriately, from CO₂-EOR operations to CO₂ storage operations. This draft guidance created considerable uncertainty among CO₂-EOR operators, since it seemed to deviate from what they perceived as the original intent of the Class VI rule. The guidance also led many to believe that in order for a CO₂-EOR operation to get “credit” for stored CO₂, a conversion from Class II to Class VI operations would likely be necessary.

Recent guidance issued by EPA confirms that CO₂-EOR operations can, in fact, result in stored CO₂, and a conversion to Class VI is not a requirement for assuring storage. Peter Grevatt, director of EPA’s Office of Ground Water and Drinking Water, issued an April 24, 2014 guidance memo to the agency’s regional water division directors that clearly states that existing CO₂-EOR wells do not need to transition from their current Class II permits for oil and gas operations to stricter Class VI permits to ensure storage, declaring that CO₂ can be safely stored under existing Class II permits. Importantly, the memo concludes that CO₂-EOR operations can switch from using a natural source to an anthropogenic source of CO₂ without triggering the need to upgrade to a stricter Class VI permit. But the memo leaves the door open to consider some CO₂-EOR wells for Class VI permits in cases where the Class II rules may not provide regulators with adequate tools to protect against “increased risks” to USDWs.

EPA has also established greenhouse gas reporting requirements under the Greenhouse Gas Reporting Program (GHGRP) for facilities that inject CO₂ underground for geologic storage and for all other facilities that inject CO₂ underground. Subpart UU of the GHGRP rules applies to CO₂ injected to enhance oil recovery; Subpart RR applies to CO₂ injected for geologic storage.

Nonetheless, regulatory barriers remain if credit for the CO₂ stored in the association with CO₂-EOR is sought. For example, under EPA “Clean Power Plan,” CO₂ storage with CO₂ -EOR is recognized as a potential compliance mechanism. If CO₂ storage is verified under Subpart RR of the GHGRP, many are concerned that Subpart RR fundamentally conflicts with state-level mineral property and resource conservation law.
Most significant concerns under Subpart RR include: (1) processes for and timeliness of EPA approval of monitoring, reporting, and verification (MRV) plans for CO₂-EOR projects, (2) what constitutes “new” activity in a CO₂-EOR project necessitating submittal of a new MRV plan, (3) how federal requirement relate to current state CO₂-EOR/Class II permitting processes, and (4) the extent to which MRV plans are subject to public litigation procedures.

Today, the main barrier to reaching higher levels of CO₂-EOR production, both in the U.S. and worldwide, is insufficient supplies of affordable CO₂. In fact, given this situation, the state of Texas may be the world’s first example of a “demand pull” to encourage anthropogenic CO₂ capture. Legislative and regulatory activity in the State of Texas has evolved to support increasing CO₂ supplies from anthropogenic sources to serve the CO₂-EOR market.

Specifically, the Texas Railroad Commission (TRRC) administers the federal Underground Injection Control (UIC) Program addressing CO₂ injection wells used for EOR (State wide Rule 46), gaining approval from EPA on April 23, 1982. Rule 46 governs fluid injection into reservoirs productive of oil, gas, or geothermal resources. Rule 46 also addresses the application process, notice and opportunity for hearing, protested applications, special equipment requirements and modification, suspension, or termination of permits for one or more of several causes. Also included in Rule 46 are requirements regarding records maintenance, monitoring and reporting, testing; plugging, and penalties for violations of the rule.

In 2009, Senate Bill (SB) 1387 instructed the TRRC to write rules for geologic storage of CO₂. SB 1387 also created the anthropogenic CO₂ storage “Trust Fund” to cover long-term monitoring of geologic storage facilities, and ordered a study on management of geologic storage on state-owned lands. The TRRC adopted new rules effective December 20, 2010. The purpose of the rules is to protect the underground sources of drinking water while promoting the capture and storage of anthropogenic CO₂, and include requirements for applications, fees, geologic site characterization, permit issuance, construction, operation, testing, monitoring and closure. These do not apply to UIC Class II wells for EOR. Conversion of a well from use in EOR to use in geologic storage is not considered to be a change in the purpose of the well.

Oil produced from an approved new EOR project or expansion of an existing project in Texas is eligible for a special EOR severance tax rate of 2.3% of the production’s market value (one-half of the standard rate) for 10 years after Commission certification of production response. For the expansion of an existing project, the reduced rate is applied to the
incremental increase in production after response certification. Effective from September 1, 2007, the State Legislature also adopted an Advanced Clean Energy and EOR Tax Reduction Bill which further reduced the effective severance tax rate for use of anthropogenic CO₂ to 1.15% for the first 7 years of EOR production.

One major barrier to large-scale implementation of CO₂-EOR in Texas does remain. For Texas to fully benefit from potential new CO₂ supplies, the lack of a unitization policy in the State inhibits the ability to assure aggregation of hydrocarbon reservoir ownership for the target reservoirs for CO₂-EOR, as well as to ensure regulatory compliance and potential future assurance for the stored CO₂. Texas is the only state in the U.S. without a compulsory unitization policy. Legislation to change this has been introduced, but not passed, due primarily to opposition by landowners. This limitation has not posed a significant barrier in West Texas, but the more fragmented ownership of some of the large East and Central Texas fields may hinder CO₂-EOR deployment in some of these fields if they cannot be voluntarily unitized.

In Phase II of this study, we will take a more detailed look at the key regulatory and environmental issues that may impact CO₂ used in the U.S. enhanced oil recovery industry that is delivered by ship-based transportation.
Feasibility Study of Ship-Based Transportation of CO₂

Chapter 3
Status and Outlook for U.S. Natural Gas Liquids
Supply and Demand: Phase 1

Prepared by:
Advanced Resources International, Inc.
Status and Outlook for U.S. Natural Gas Liquids Supply and Demand: Phase 1

Introduction

This report provides an overview of the current domestic Natural Gas Liquids (NGL) supply and demand situation. NGLs are composed of natural gas liquids (ethane, propane, iso – and normal butane, and pentanes plus (natural gasoline)) produced at natural gas processing plants. Additional sources of NGLs, called liquefied refinery gases (LRG), are produced as byproducts from crude oil processing at oil refineries. Almost all growth in NGLs production over the past decade has been attributable to natural gas liquids from gas processing plants and, therefore, gas plant NGLs will be the focus of this report.

Background

After nearly twenty years of decline, domestic natural gas plant liquids (NGL) production hit a low of 1.6 million barrels per day (MMB/D) in 1990. With expectations of scarcity and higher prices for natural gas, much of the domestic petrochemical industry, particularly along the Mississippi River, relocated to areas with more secure, accessible supplies of NGLs as well as naphtha, an alternative to using NGLs as feedstock in chemical plants.

Subsequently, NGL production rebounded and then stayed relatively flat at 1.8 to 1.9 MMB/D through 2008, but this rebound was met with skepticism by industry as to its sustainability. As such, industry’s pessimistic outlook for future NGL production remained entrenched and petrochemical operations continued to relocate overseas, relying primarily on naphtha as the preferred feedstock for ethylene production.

However, since 2008, U.S. production of NGLs (from gas plants) has surged -- from 1.8 million barrels per day in 2008 to 3.0 million barrels per day in 2014, Figure 1.
This dramatic change in the domestic NGL supply situation has been brought about by the “shale revolution”, particularly the discovery and development of wet, liquids-rich shale gas plays such as the Woodford, SW Marcellus, and Utica. Additionally, liquids-rich associated gas from “tight oil” plays such as the Bakken, Eagle Ford and the stacked formations of the Permian further boosted NGL supply.

**Status of Domestic NGL Supply**

Much of the growth in domestic NGL supply has been from increased production of ethane and propane. Ethane production increased by 0.4 MMB/D -- from 0.7 MMB/D in 2008 to 1.1 in 2014 -- despite rejection of an estimated ~0.8 MMB/D of technically recoverable ethane in 2014. Meanwhile, propane production increased by 0.5 MMB/D over this same time period, from 0.5 MMB/D to 1.0 MMB/D. In addition, production of iso-butane, normal butane, and pentane (natural gasoline) increased by a combined 0.4 MMB/D, from 0.6 MMB/D to 1.0 MMB/D. Figure 2 illustrates the recent growth of NGL production by the five key product streams.
With the strong growth in domestic NGL production, in 2011 the US became a net exporter of natural gas plant liquids and liquefied refinery gases for the first time since the data for imports/exports of NGLs has been recorded.

**NGL Demand**

**Ethane.** The primary driver of ethane demand is feedstock for production of ethylene and other chemicals in competition with naphtha. With increasing production of low cost wet (liquids-rich) natural gas, the cost advantage of producing ethylene from ethane has stimulated expansion and new construction of ethane crackers. Additionally, dedicated ethane pipelines, export terminals, and tankers are under development. However, increases in domestic ethane production have greatly exceeded growth in domestic demand. As such, increased ethane exports are needed to remedy the current surplus situation and low price.
**Propane.** Propane, the most seasonal of the NGL streams, is used in a variety of capacities, from residential heating in the winter, to agricultural use in the fall and petrochemical use the year round. With the steady growth of domestic propane production, Figure 3, the US began exporting propane in 2011 and exported 0.4 MMB/D of propane in 2014 (0.3 MMB/D, net), Figure 4. The exports primarily depart from Gulf Coast terminals located in close proximity to the large NGL processing complex at Mont Belvieu, TX. Additionally, propane is also exported from the Marcus Hook facility on the East Coast. Proposed West Coast propane export terminals in Oregon and Washington are in the early stages of planning.

![Figure 3. Growth of Domestic Propane Production](image)

**Butane and Pentane.** Normal butane can be used for gasoline blending and as a petrochemical feedstock, whereas isobutene is primarily used in the production of motor gasoline by refineries. Pentane is primarily used as a blending stock for transportation fuel and as a diluent for heavy oil. These heavier NGL components, iso and normal butane and pentanes plus, are largely consumed domestically. However, in 2014 the US exported a modest volume of butane (55 MB/D, net) and a moderate volume of pentane (152 MB/D, net).

**NGL Pricing**

NGL prices have collapsed in the last two years due to oversupply and a decline in the price of oil. In the Marcellus, one of the primary regions of NGL supply growth, NGL prices have been hit particularly hard, declining by over 70% in the 18 month period ending in mid-2015. Figure 5 illustrates the decline in NGL sales price for a Marcellus operator, EQT, and demonstrates that the initial decline in NGL pricing started with the NGL over supply and then continued with the decline in oil prices.
Ethane, currently with a Mt. Belvieu price of $7.80/B ($0.19/gal or ~$2.80/MMBtu), is being rejected widely as operators often receive more by keeping ethane in the gas stream than processing it. Similarly, propane prices have collapsed as well, with current prices of about $16.80/B ($0.40/gal or $4.40/MMBtu).

Driving the economics of exporting ethane is the price spread between ethane and naphtha, which has favored ethane over the past few years due to the lower cost of ethane and a higher oil price. Overseas, many of the crackers used for the production of propylene/ethylene, the basic building blocks of plastics, use naphtha as a feedstock. Naphtha pricing tracks global oil prices closely, meaning that in the high oil price world of 2012 through the first half of 2014, naphtha was at a disadvantage to ethane as a feedstock. The oil price decline has narrowed the spread between ethane and naphtha, potentially reducing the economic attractiveness of the multiple new “world scale” ethane crackers currently under construction in the U.S. However, the long term fundamentals of a growing ethane supply remain intact and exports and/or new domestic crackers are needed to balance supply and demand.

**NGL Pipeline System and Exports**

To reduce the NGL glut in regions such as the Appalachian Basin, major new NGL pipelines are on line or under construction, such as the Enterprise ATEX ethane pipeline, to transport NGLs to processing and export hubs on the Gulf Coast.
Ethane shipments to Canada from PADD 2, to be used by Canadian petrochemical facilities, have also commenced on newly built pipelines. The Mariner East project, which Sunoco is currently considering expanding, transports NGLs from the Marcellus Shale to the Marcus Hook export terminal on the East Coast. Companies like Ineos have contracted for the shipment of ethane from Marcus Hook for use at their ethane cracking facilities in Europe.

**Figure 6. Domestic NGL Pipelines**

Much of the domestic NGL storage, processing, and export infrastructure is located on the Texas Gulf Coast. In response to increasing domestic NGL supplies and in anticipation of the widening of the Panama Canal in 2016, which will allow for the transit of the largest NGL product ships to and from Asia, many NGL export terminals on the Gulf Coast are undergoing expansions, such as Enterprise’s Houston Ship Channel and Targa Resource’s Galena Park Marine Terminal. Also, a new LPG export terminal with initial export capacity of 4.4 million barrels per month is currently under construction in Freeport, TX, and is due on-line in the second half of 2016. These projects will enable the U.S. to maintain its position as the largest exporter of LPG in the world.
Phase II Work: The Outlook for NGL Supply and Demand

As part of our Phase II work, we would build on our review of the current status of domestic NGL supply, demand and exports to provide a longer outlook for this important hydrocarbon product for years 2015-2025. We would use our proprietary NGL data base and economic models, to provide this information.
Feasibility Study:
Liquid Gas Carrier with CO2 Back-Haul

Dated: 8 April 2016

Rev: 0
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1. Introduction

Fearnoil commissioned ABSG Consulting (ABSG) to perform a study to determine whether carriage of liquid CO2 is a feasible option for natural gas liquids (NGLs) and liquefied petroleum gas (LPG) shippers. The object would be maximize utilization of existing or proposed vessels in liquefied gas service loading cryogenic liquid gases at US Gulf of Mexico or Atlantic coast ports as an alternative to returning to the US in ballast (empty of cargo). The source of the liquid CO2 (LCO2) would be CCS projects in Europe or other locations to be specifically determined at a future development phase. The study examined the technical, operational and regulatory compliance issues to be considered for liquefied-gas vessels to be used for backhaul cargos of LCO2.

The report includes the results of the study, comprising a basic technical evaluation of the capability of liquefied-gas carriers to safely and routinely transition from carrying NGLs to CO2 and vice versa, and any special equipment, systems or procedures to make it possible.

It also outlines the economic framework to determine commercial possibilities for more detailed studies if specific opportunities are identified as a result of this report.

This report will summarize and explain the results of the feasibility study with conclusions and recommendations for additional or more detailed areas of analysis where needed.

In the context of this report, for the avoidance of confusion with multiple marine vessel categories and types, the term liquefied gas carrier is used to cover the entire range of vessels with the technical capacity to carry liquid gases, including CO2. The term natural gas liquids (NGLs) is used throughout this report and covers the spectrum of liquefied gases carried by ship. The term liquefied petroleum gas (LPG) is used in the shipping industry to refer mainly to propane and butane (see Table 1 below for description of NGLs).

To produce this report, ABSG interviewed liquefied gas ship owners, large international oil company geologists, marine cryogenic equipment suppliers, US based CO2 pipeline operators, process systems engineers, US Coast Guard technical compliance staff and our own subject matter experts within the ABS Global Gas Solutions group. The information contained in this report was developed from phone conversations, email exchanges, internet research, peer review and ABSG’s marine shipping technical knowledge and experience. It is believed to be the best currently available information as of the date of issue of this report.

1.1. Background

As a result of improved onshore oil and gas extraction technologies over the last decade, US domestic oilfields have produced significant quantities of oil, natural gas and natural gas liquids (NGLs). These products have become available for export as a result of supply exceeding demand in the US.
Until recently, US export capability has been limited, but major NGL export projects have been developed in the US and are now coming on stream to supply energy products to world markets. NGLs are in demand globally as a feedstock for various industrial and chemical processes (Table 1).

NGL exporting involves the use of specialized ships known as liquefied gas carriers with pressurized cargo tanks and cargo handling systems capable of carrying liquefied gases with temperatures as cold as -160°C (260°F) throughout a range of pressures. These ships are designed and built according to stringent international design criteria to permit safe transport and handling of cryogenic and pressurized liquid gases.

At the same time, carbon capture and storage (CCS) projects have created a potential need to transport captured CO2 from the emitter or capture location to the end-user or storage location. Carbon capture and storage is a set of technologies aimed at capturing, transporting, and storing CO2 emitted from power plants and industrial facilities. The goal of CCS is to prevent CO2 created in power generation, fossil fuel extraction and other industrial processes from reaching the atmosphere by injecting and storing it in suitable underground geological formations.

Table 1 Common Natural Gas Liquids (source: EIA)
1.2. Definitions and Acronyms

**ABS - ABS Group Consulting**

**BOG** – boil-off gas, vapour generated by evaporation of liquid gas cargos

**CO₂** – CO₂, Chemical name and common acronym for carbon dioxide

**C₂** – common abbreviation of chemical name for ethane, C₂H₆

**CCS** – Carbon Capture and Storage

**EIA** – Energy Information Agency – US government agency that monitors and reports US energy statistics

**EOR** – Enhanced Oil Recovery, pressure injection of CO₂ into oil reservoirs to improve oil and gas production

**GGS** - Global Gas Solutions, team of liquefied gas marine transportation subject matter experts within ABS

**HGL** – Hydrocarbon Gas Liquid, equivalent term for NGL and LPG

**IEA** – International Energy Agency, autonomous international NGO that examines energy issues and policies

**IGC** – International Gas Carrier Code

**IMO** – International Maritime Organization

**LCO₂** – Liquid Carbon Dioxide

**LNG** – Liquefied natural gas- primarily methane with ethane, propane, butane, pentane and other trace components

**LPG**- Liquefied Petroleum Gases – gases that have been liquefied by cooling or pressurizing for ease of transport and storage. In marine shipping, LPG refers mainly to propane and butane.

**NGL** Natural Gas Liquids –hydrocarbons composed exclusively of carbon and hydrogen (see Table 1)

**OCIMF** – Oil Companies International Marine Forum, ship inspection and reporting service and data base

**SIRE** – Ship Inspection Report – standard format vetting inspection report used by charterers, shippers, terminals and others to determine vessel compatibility and suitability for hire

**USCG** – United States Coast Guard
1.3. Executive Summary
Discussion with ABS Global Gas Solutions technical experts, CO2 pipeline operators, US Coast Guard engineering and hazardous materials staff, cryogenic pump makers and LPG vessel operations executives indicate that from a technical standpoint, liquid CO2 can be carried aboard suitable liquefied gas vessels with approvals, precautions and handling procedures similar to those used for other liquefied gases carried as cargo aboard ships.

Quoting an email message received from a senior executive of a well-established European liquefied-gas carrier with long experience in the transport of cryogenic liquid gases, “Technically, transporting CO2 is not a big deal. (You) (j)ust have to choose temp/pressure to optimize your supply chain”.

The biggest challenge in utilizing existing liquefied-gas carriers is the maximum allowable working pressure of the cargo tank, which would be higher than that used for regular LPG service. Although there are existing liquefied gas carriers capable of carrying LCO2, because of the requirement for increased pressure capability, they are generally smaller and less suited to long-haul trans-Atlantic transport.

Basic vessel technical requirements are:

- Type 2G or 3G liquefied gas carrier with, or capable of being approved for, a Certificate of Fitness for liquid CO2
- Type C (pressure vessel) containment system with greater than 7 Bar g design pressure and appropriate safety margin
- Tanks and cargo systems suitable for cryogenic liquid gases colder than -55°C
- Permission from the relevant authorities to carry liquid CO2
- Sufficient cargo carrying capacity to allow competitive unit freight cost

Suitable vessels for LCO2 backhaul service would fall into the “handy-size” gas carrier category; vessels with approximately 15,000m3 to 30,000m3 capacity. The notional candidate vessels identified in this report have less than 15,000m3 cargo capacity.

Increased US NGL exports are driving requirements for more liquefied gas carriers to lift cargos from Gulf and East coast ports. Existing designs of handy-size liquefied gas carriers are a close fit, but would need to be tailored at the newbuilding design stage to make carriage of LCO2 possible. There may be an opportunity to take advantage of increased numbers of handy-size newbuild orders to specify LCO2 capable ships at a cost which should be only marginally higher than the cost of a standard liquefied gas carrier.

Potential time loss and the logistical and operational elements of changing cargo grades and voyage deviations will also significantly affect the feasibility of LCO2 backhaul on a specific trade route, charter or contract of affreightment. Potential for net hydrocarbon emissions increase also has to be evaluated in the context of environmentally responsible shipping and CCS project objectives.
A variety of economic and operational factors of moderate complexity and likelihood must be aligned in order for ship-owners to regard LCO2 backhaul as an attractive market. These include:

- Availability of suitable vessels with the requisite cargo tank design pressure
- Development of needed infrastructure (CO2 storage and marine transfer facilities)
- Long term commitment of project stakeholders, including shippers and CCS project developers and sponsors
- Sufficient economic inducement for all participants in the value chain

On the CO2 market development front, North American CO2 users are interested in new and additional supply sources, such as that represented by importing LCO2 from CCS projects overseas as part of a total supply chain carbon reduction strategy.

According to ABSG discussions with US oil major E&P geologists and drillers, a potential demand for additional CO2 supply exists due to a variety of factors:

- There is competition for EOR CO2 supply among onshore field operators
- Access to current sources of CO2 (underground geological structures) can be complicated
- EOR projects for the oil majors are long-term and not sensitive to current oil prices
- Oil majors are always on the lookout for reliable CO2 supply options.
- Opportunity to participate in “green” CCS projects that reduce overall value chain carbon emissions can be an incentive

Discussion with CO2 pipeline operator representatives also indicated that the US market can be fragmented and subject to variability with regard to supply and demand, concluding that a credit-worthy customer at the right price and a long term volume commitment could “get a deal done.”

Significant expansion of US NGL exports will drive increasing numbers of liquefied -gas carriers to US Gulf Coast ports, increasing opportunities and competition among shippers and ship owners for backhaul cargos. As of 2015, the US was the top exporter of NGLs, with over 250 million barrels shipped, ahead of the next largest producer UAE, by over 1.25 million barrels.

In general, the CO2 backhaul concept is technically feasible with appropriate precautionary measures. Favorable shipping and logistics factors provide support and opportunity for development of the concept. Additional study identifying specific vessels, containment system modification requirements, trade routes, actual CO2 sellers and buyers, load and discharge ports and infrastructure requirements must be completed for proof of concept.

1.4. US Natural Gas Liquids Export Market Development

A number of projects have been proposed to export NGLs from US Gulf Coast and Atlantic ports. According to the US Energy Information Agency (EIA), “Several companies such as Phillips 66, Targa Resources Partners, Sunoco Logistics, and Enterprise Products Partners have announced plans to expand or build new HGL (hydrocarbon gas liquid) export facilities, mostly along the Gulf Coast to take
advantage of a growing excess supply of propane, normal butane, and ethane". The export projects rely partially on the use of liquefied gas carriers due to the special nature of the products they carry. It is expected that many ships used in NGL export service will return to the US from their discharge ports empty. Optimization of the transportation chain to include a cargo to be carried on the return voyage (sometimes referred to as backhaul) would reduce costs and increase operational efficiency by using fewer ships to move more cargo.

Table 2 Ethane and LPG Export Projects in the US (source: ABSC research)

<table>
<thead>
<tr>
<th>Project</th>
<th>Location</th>
<th>Capacity</th>
<th>Start Date</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Enterprise Products</strong></td>
<td>Houston Ship Channel Morgan’s Point</td>
<td>2 marine berths 200,000 bbl/d (32,000 m3/d)</td>
<td>3Q 2016</td>
</tr>
<tr>
<td><strong>Morgan’s Point</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Sunoco Logistics</strong></td>
<td>Marcus Hook, PA</td>
<td>Ph I 70,000 bbls/d (11,000 m3/d)</td>
<td>Currently operating Ph II 2Q 2017</td>
</tr>
<tr>
<td><strong>Mariner East I &amp; 2</strong></td>
<td></td>
<td>Ph II 450,000 bbl/d (71,000 m3/d)</td>
<td></td>
</tr>
<tr>
<td><strong>Targa Resources</strong></td>
<td>Houston Ship Channel Galena Park Marine Terminal</td>
<td>4 marine berths Ph II Expansion 200,000 bbl/d (32,000 m3)</td>
<td>Currently operating</td>
</tr>
<tr>
<td><strong>Conoco Phillips</strong></td>
<td>Freeport LPG Export Terminal Freeport, TX</td>
<td>2 marine berths 146,000 bbl/d (23,000 m3/d)</td>
<td>3Q 2016</td>
</tr>
</tbody>
</table>

1 EIA, Hydrocarbon Gas Liquids (HGL): Recent Market Trends and Issues, Nov 2014, pg 17
1.4.1. Carbon Capture and Storage (CCS)

Additionally, an active and established market for CO2 used in enhanced oil recovery (EOR) exists in North America, with the majority of activity occurring in the Gulf of Mexico region. Most EOR operations involve transport of CO2 from existing geological formations to onshore oil fields in Texas, Louisiana, and Oklahoma. Transport is accomplished via pipeline with the CO2 compressed to super-critical pressure (124 bar g – 150 bar g / 1800 – 2200 psig) in its “dense” phase. According to discussion with exploration and production geologists and other specialists\(^2\), EOR is a long term investment with a 10-15 year payback period that is less sensitive to current oil prices than other oil and gas drilling activities. Supply from geological resources can be structurally complicated and subject to competition from other oil major E&P customers. Due to these factors, North American CO2 users are interested in new and additional supply sources, such as that represented by importing LCO2 from CCS projects overseas as part of a total supply chain carbon reduction strategy.

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\(^2\) ABSC phone conversations with drilling specialists and geologists at oil major E&P subsidiary and major CO2 pipeline operator (names withheld for confidentiality reasons).
### Table 3 CCS Projects for EOR in the US (source: Global CCS Institute)

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Stage</th>
<th>Operation Date</th>
<th>Industry</th>
<th>Capture Capacity (Mtpa)</th>
<th>Transport Type</th>
<th>Primary Storage Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Air Products Steam Methane Reformer EOR Project</td>
<td>Operate</td>
<td>2013</td>
<td>Hydrogen Production</td>
<td>1</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Century Plant</td>
<td>Operate</td>
<td>2010</td>
<td>Natural Gas Processing</td>
<td>8.4</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Coffeyville Gasification Plant</td>
<td>Operate</td>
<td>2013</td>
<td>Fertilizer Production</td>
<td>1</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Enid Fertilizer CO2-EOR Project</td>
<td>Operate</td>
<td>1982</td>
<td>Fertilizer Production</td>
<td>0.7</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Lost Cabin Gas Plant</td>
<td>Operate</td>
<td>2013</td>
<td>Natural Gas Processing</td>
<td>0.9</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Shute Creek Gas Processing Facility</td>
<td>Operate</td>
<td>1986</td>
<td>Natural Gas Processing</td>
<td>7</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Val Verde Natural Gas Plants</td>
<td>Operate</td>
<td>1972</td>
<td>Natural Gas Processing</td>
<td>1.3</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Kemper County Energy Facility</td>
<td>Execute</td>
<td>2016</td>
<td>Power Generation</td>
<td>3</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Petra Nova Carbon Capture Project</td>
<td>Execute</td>
<td>2016</td>
<td>Power Generation</td>
<td>1.4</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Riley Ridge Gas Plant</td>
<td>Evaluate</td>
<td>2020</td>
<td>Natural Gas Processing</td>
<td>2.5</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
<tr>
<td>Texas Clean Energy Project</td>
<td>Define</td>
<td>2019</td>
<td>Power Generation</td>
<td>2.4</td>
<td>Pipeline</td>
<td>Enhanced oil recovery</td>
</tr>
</tbody>
</table>

#### 1.5. Carbon Dioxide Marine Transport

Carbon Dioxide is currently transported commercially in small quantities in liquid form aboard dedicated, converted or purpose built ships that carry the liquid at higher pressure than most LPG carriers could accommodate (Table 4). The transport routes are short hauls between ports in the Northern Europe / Scandinavia region. Because of the higher pressures and resulting cargo tank specifications, the volume that can be carried is limited.

*Table 4 Carbon Dioxide Carrier Yara Froya (source: DNV-GL registry of ships)*

<table>
<thead>
<tr>
<th>Vessel:</th>
<th>Yara Froya</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flag:</td>
<td>Norway</td>
</tr>
<tr>
<td>Port:</td>
<td>OSLO</td>
</tr>
<tr>
<td>Owner:</td>
<td>Yara Gas Ship AS</td>
</tr>
<tr>
<td>Manager:</td>
<td>Larvik Shipping AS</td>
</tr>
</tbody>
</table>

---

From Table 4 above, it can be seen that the specifications for these dedicated CO2 carriers compromise carrying capacity in order to carry CO2 at higher temperatures and pressures. The CO2 is used in the beverage, food storage and other industrial applications in smaller quantities than can be efficiently transported over longer distances.

Two sister vessels to Yara Froya are in operation in Europe under the same owner. Note that Yara Froya is designated a type 3G ship, which indicates design for the least hazardous cargos (see 1.4 below for more details). There is also a purpose built CO2 carrier in operation, the Coral Carbonic (built 1999), operated by Anthony Veder between ports in Northern Europe and Scandinavia. Like the
Yara vessels, Coral Carbonic carries the liquid CO2 at a temperature of -40 C and pressure up to 18 Bar, with 1250m3 capacity.

There is currently no long haul marine transportation of CO2 being conducted.

1.6. General Description of Liquefied-Gas Carriers

Liquefied Gas carriers can be divided into two main groups:

Liquefied Petroleum Gas (LPG) Carriers, which are designed to carry mainly butane, propane, butadiene, propylene, vinyl chloride monomer (VCM) and are able to carry anhydrous ammonia.

Ethylene / Ethane Carriers, designed for the colder temperatures (-104°C/-89°C at atmospheric pressure) required for those two commodities.

Liquefied Natural Gas (LNG) Carriers, which are designed to carry liquefied natural gas (which is mostly methane).

In general, large LNG Carriers (+ 125,000m3 capacity) and Very Large Gas Carriers (VLGC) (+80,000m3 capacity) are not suited for pressurized cargos and are outside the scope of this report. Recent developments in the small scale LNG marine fuel and other natural gas markets have resulted in design, construction and deployment of small carriers with pressurized “Type C” cargo tanks and liquefied-gas capability suitable for LNG and LPG and that could be suitable for CO2 service. These small scale LNG vessels would also be considered as candidates for CO2 backhaul service.
Gas carriers are classed by the International Maritime Organization (IMO)\(^4\) into three designations based on level of cargo hazard. They are described in the International Code of Safety for Vessels Carrying Liquefied Gases in Bulk (IGC Code):

i) Type 1G, designed to carry the most hazardous cargoes

ii) Type 2G and 2PG, designed to carry cargoes having a lesser degree of hazard

iii) Type 3G, designed to carry cargoes of the least hazardous nature.

Under IMO, Class and USCG rules, vessel must apply for and exhibit an International Certificate of Fitness for the Carriage of Liquefied Gases in Bulk that certifies that the ship complies with the design and construction criteria of the IGC code and is certified to carry specific listed liquefied gases in bulk. Liquid CO\(_2\) is a listed cargo in the IGC Code. The certificate also lists the conditions of carriage of the

\(^4\) Non-Governmental Organization of the UN that promulgates international safety standards for ships
various products, such as the cargo tank the cargo is to be loaded in, temperature, pressure, relief valve settings and other parameters.

An excerpt from the Gas Form C from the Oil Companies International Marine Forum (OCIMF)\(^5\) Ship Inspection Report (SIRE) vessel data base is provided below (Table 5) as an example of the range of cargos that can be carried by a liquefied gas carrier.

*Table 5 Gas Form C excerpt for 27,000m\(^3\) liquefied-gas vessel from OCIMF SIRE report (Source: Evergas)*

<table>
<thead>
<tr>
<th>Cargo</th>
<th>Temp at atm. Press (Celsius)</th>
<th>Density at atm. Press (kg/m(^3))</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane</td>
<td>-163</td>
<td>545</td>
</tr>
<tr>
<td>Ethylene</td>
<td>-104</td>
<td>568</td>
</tr>
<tr>
<td>C-Ethane (0,5 mol% Methane in Liq. Phase)</td>
<td>-89</td>
<td>545</td>
</tr>
<tr>
<td>Propylene</td>
<td>-48</td>
<td>609</td>
</tr>
<tr>
<td>C-Propane (2,5 mol% Ethane in Liq. Phase)</td>
<td>-45</td>
<td>583</td>
</tr>
<tr>
<td>Vinyl Chloride Monomer (VCM)</td>
<td>-14</td>
<td>969</td>
</tr>
<tr>
<td>Iso-Butane</td>
<td>-12</td>
<td>594</td>
</tr>
<tr>
<td>Butylenes</td>
<td>-7</td>
<td>625</td>
</tr>
<tr>
<td>Butadiene</td>
<td>-5</td>
<td>650</td>
</tr>
<tr>
<td>N-Butane</td>
<td>0</td>
<td>602</td>
</tr>
<tr>
<td>Methyl Chloride</td>
<td></td>
<td></td>
</tr>
<tr>
<td>DME</td>
<td>-25</td>
<td>734</td>
</tr>
<tr>
<td><strong>Other Cargoes</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Acetaldehyde</td>
<td>20</td>
<td>778</td>
</tr>
<tr>
<td>Dimethyl Amine</td>
<td>7</td>
<td>666</td>
</tr>
<tr>
<td>Ethyl Chloride</td>
<td>13</td>
<td>903</td>
</tr>
<tr>
<td>Diethyl Ether</td>
<td>35</td>
<td>700</td>
</tr>
<tr>
<td>Isoprene (Monomer)</td>
<td>34</td>
<td>666</td>
</tr>
<tr>
<td>Isopropyl Amine</td>
<td>32</td>
<td>676</td>
</tr>
<tr>
<td>Monoethyl Amine</td>
<td>17</td>
<td>687</td>
</tr>
<tr>
<td>Pentanes/Pentenes</td>
<td>36 / 30</td>
<td>605 / 608</td>
</tr>
<tr>
<td>Vinyl Ethyl Ether</td>
<td>36</td>
<td>750</td>
</tr>
</tbody>
</table>

For transport efficiency, gas cargoes are transported in liquid form. Because of their physical and chemical properties, they are carried either at pressures greater than atmospheric or at temperatures below ambient, or a combination of both.

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\(^5\) OCIMF through its ship inspection reporting (SIRE) and subscription database program provides vetting, and quality assurance services and other information for shippers, terminal operators and charterers to make decision about the suitability of vessels for a particular trade
Gas carriers are generally grouped as follows:

i) Fully Pressurized

ii) Semi-pressurized and refrigerated

iii) Fully refrigerated

Only ships with fully pressurized and semi-pressurized cargo tanks capable of handling liquid gas cryogenic cargos at more than 7 Bar g pressure could potentially be considered as suitable for LCO2 service.

*Figure 4 Typical modern LPG carrier (source: Wartsila and Evergas)*
2. Technical Evaluation

Carriage of liquid CO2 requires special considerations. The study researched available information and resources about the requirements for safely transporting liquid CO2, including discussion with CO2 pipeline operators and liquefied gas carrier operations specialists.

2.1. CO2 Properties and Characteristics

For carriage as cargo aboard LPG carriers, CO2 must be kept in its liquid state at temperatures and pressures above its triple point\(^6\), approximately -56.6°C and 5.2 Barg (Fig 3).

### Table 6 CO2 Properties

<table>
<thead>
<tr>
<th>CO2 liquid properties:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Density</td>
<td></td>
</tr>
<tr>
<td>Solid at 1 atm and –78.5 °C</td>
<td>1562 kg/m³</td>
</tr>
<tr>
<td>Liquid at saturation –37°C</td>
<td>1101 kg/m³</td>
</tr>
<tr>
<td>Gas at 1 atm and 0 °C</td>
<td>1.977 kg/m³</td>
</tr>
<tr>
<td>Liquid/gas equivalent</td>
<td>845x (vol/vol) expansion</td>
</tr>
<tr>
<td>(1.013 bar and 15 °C per kg of solid)</td>
<td></td>
</tr>
<tr>
<td>Boiling point (Sublimation/deposition)</td>
<td>-78.45 °C</td>
</tr>
<tr>
<td>Vapor pressure (at 20 °C or 68 °F)</td>
<td>57.291 bar</td>
</tr>
<tr>
<td>Triple point temperature</td>
<td>-56.56 °C</td>
</tr>
<tr>
<td>Triple point pressure</td>
<td>5.187 bar</td>
</tr>
</tbody>
</table>

### Table 7 Liquid Phase CO2 Pressure, Density and Temperature relationship at saturation (source: NIST Webbook)

<table>
<thead>
<tr>
<th>Pressure (Bar)</th>
<th>Temp (°C)</th>
<th>Density (kg.m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>-53</td>
<td>1166</td>
</tr>
<tr>
<td>7</td>
<td>-49</td>
<td>1152</td>
</tr>
<tr>
<td>8</td>
<td>-46</td>
<td>1140</td>
</tr>
<tr>
<td>9</td>
<td>-43</td>
<td>1128</td>
</tr>
<tr>
<td>10</td>
<td>-40</td>
<td>1120</td>
</tr>
<tr>
<td>11</td>
<td>-37</td>
<td>1107</td>
</tr>
<tr>
<td>12</td>
<td>-35</td>
<td>1097</td>
</tr>
<tr>
<td>13</td>
<td>-33</td>
<td>1087</td>
</tr>
<tr>
<td>14</td>
<td>-31</td>
<td>1078</td>
</tr>
<tr>
<td>15</td>
<td>-29</td>
<td>1070</td>
</tr>
</tbody>
</table>

\(^6\) Triple Point: The temperature and pressure at which the three phases (gas, liquid, and solid) of a substance coexist in thermodynamic equilibrium.
If the temperature falls below -56.6, the CO2 can solidify into dry ice which could damage cargo pumps and tank internals, block piping and valves (including safety relief valves), and cause delays in vessel and terminal operations. If the CO2 is allowed to warm, it could exceed the pressure setting of the safety relief valves resulting in venting of the CO2 vapor to atmosphere. Venting of CO2 vapor to atmosphere does not present a flammability hazard as other liquid gases do, and it would be a simple and effective way to maintain the required cargo tank pressure and temperature. An evaluation of the net emissions impact of purposely emitting CO2 would have to be performed for the specific vessel and voyage as it may be contrary to the CCS objective.

Figure 5 Carbon Dioxide temperature and pressure (source: Global CCS Institute)

The carbon dioxide must be carried within a temperature and pressure range that will prevent formation of solid CO2 (dry ice) and not exceed the maximum allowable relief valve settings (MARVS) of the ship’s cargo tanks. As shown in Fig 3 above, the range of acceptable temperature would be between -55°C up to approximately -45°C. The saturation curve for LCO2 over the required range of temperature and pressure for carriage as cargo is shown in Fig 5.
Figure 6 Saturation Properties of Carbon Dioxide (source: NIST chemistry WebBook)

The range of acceptable cargo tank pressures with appropriate safety margins is shown in Fig 6.

Figure 7 Range of cargo tank pressure for liquid CO2 and safety margins (Source: Tebodin Netherlands BV)

Figure 7 represents a conservative example of pressures and safety margins for a cargo tank with liquid CO2 cargo. From a physical characteristics perspective, if the selected ship’s cargo tank and piping can handle up to 7 Bar g pressure, it can be concluded that liquid CO2 can be carried as cargo in existing fully or semi-pressurized containment liquefied gas carriers with precautions and handling procedures similar to those used for other liquefied gases carried as cargo aboard ships. Carriage of CO2 in a suitably capable ship would also require approval from the appropriate Flag-state authority.
of the vessel\textsuperscript{7} and from the US Coast Guard for vessels trading to US ports. The USCG approval process is dependent on prior issuance of an IMO Certificate of Fitness by the flag state or recognized organization (classification society) to carry LCO\textsubscript{2}, but is normally routinely granted upon application with the appropriate documentation.

2.2. Liquefied Gas Carrier LCO\textsubscript{2} Cargo Handling

Liquefied gas carriers are built according to the IGC code, which specifies design and construction criteria for the safe carriage of cryogenic liquid gases with varying levels of hazard.

Assuming that the ships are acceptable and approved for LCO\textsubscript{2} loading, technical aspects of cargo loading, transport and handling must be considered. This report assumes that suitable LCO\textsubscript{2} loading and discharge facilities are available. The vessel cargo transfer and handling system can be broken down as follows:

- Cargo transfer piping - Manifolds, piping, valves, flanges, gaskets, expansion joints, loops, bellows, safety relief valves, reducers and piping interconnections.
- Containment System - cargo tank, level gauging system, safety relief valves, tank hold space, support structure, access ways (hatches, manholes, inspection ports).
- Cargo handling equipment - Pumps, compressors, heat exchangers, refrigeration systems, pressure relief, boil-off gas systems, volume, flow, level, temperature and pressure indicating systems
- Auxiliary systems – inerting systems, cooling water, ballast, refrigerants, deck tanks, other connected systems.

2.2.1. Cargo Transfer Piping

The IGC code specifies requirements for cryogenic cargo piping. If the vessel is certified to carry cryogenic liquid gases, its piping system would be suited for the same cryogenic temperatures and pressures. Pressure relief in the event of trapped liquid or gas causing a potential overpressure is provided in the form of pressure relief valves that are designed to discharge excess pressure safely away from personnel, systems and equipment. Pressure relief systems are designed to ensure that any venting is in the vapor phase to avoid discharge of cold liquid that could be a hazard to personnel or ship structure. Pressure relief vents are usually piped to a vent mast arrangement that discharges upward and safely away from working areas and hazardous locations. This design feature would prevent ejection of CO\textsubscript{2} liquid or solids through the pressure relief system.

Cargo transfer piping is also fitted with valves that may be remotely, manually or automatically operated by the cargo transfer system and / or the emergency shutdown systems required by the IGC

\textsuperscript{7} IGC Code Model Form Paragraph 3: “Only products listed in chapter 19 of the Code or which have been evaluated by the Administration in accordance with paragraph 1.1.6 of the Code, or their compatible mixtures having physical proportions within the limitations of tank design, should be listed. In respect of the latter "new" products, any special requirements provisionally prescribed should be noted.”
Code. These valves are actuated in the event that system parameters of temperature, pressure, level, gas detection or fire detection are exceeded.

Consideration of temperature and pressure changes within piping and flow across valves and other fittings installed in the piping must be considered by vessel cargo system operators.

2.2.2. Liquefied Gas Carrier Containment Systems

In order to carry liquefied gases at pressures greater than ambient, liquefied gas carriers are fitted with Type C containment systems as defined in the IGC code and incorporated into US regulation. They are built to stringent pressure vessel standards. They are most commonly insulated with polyurethane panels or foam. (Figure 8).

Figure 8 Type C Tank design and construction features (source: www.clean-baltic-sea-shipping.com)

Type C tanks are independent of the vessel’s hull, supported on tank saddles usually fitted to the tank hold space deck. One of the support saddles is fitted with a sliding arrangement to allow for tank expansion and contraction.

Design criteria are based on, among other things, the pressure, density and temperature of the cargo to be carried. This determines the thickness of the steel required for construction of the tank and therefore the maximum pressure the tank is built to withstand. Chapter 4 Section 4.2.4.4 of the IGC Code specifies the minimum design pressure to which the cargo tanks should be built to meet the Code requirement for a Type C tank. Design pressure is very often based on the operational profile of the vessel and may be higher than the minimum (Type C) design pressure. Factors of tank size, cargo liquid density at the design temperature and allowable stresses are included in the determination of the design pressure.
The material of construction is also specified for cryogenic liquids. Acceptable materials include low
temperature carbon steel, stainless steel, aluminium and nickel steel alloys.

Liquefied gas carriers fitted with Type C cargo tanks and with IMO Certificates of Fitness (COF) to
carry cryogenic liquid gases in the design pressure range for marine transport of LCO2 may be suitable
candidates for consideration for backhaul cargos. Any candidate vessel’s containment system would
have to be specifically confirmed and permitted in accordance with the IGC Code design criteria prior
to receiving approval to carry LCO2.

When an existing candidate vessel(s) has been selected, this would be part of the in-chartering and
vetting process. In the event that a new-build vessel is specified for LCO2 backhaul, this would be part
of the design review process.

2.2.3. Cargo handling equipment

In order to transfer the LCO2 from the ship to the shore reception facility, it must be pumped using the
ship’s cargo handling equipment. Most liquefied gas carriers are fitted with deepwell pumps with the
pump volute and impeller within the cargo tank connected by a shaft to an electric motor mounted on
the top of the tank. Alternatively, they may be fitted with submerged, centrifugal type pumps with
capability to pump a wide range of liquids with differing densities (Fig 8).

According to discussion with liquefied gas ship operators and pump manufacturers, current installed
pumps would be able to pump LCO2 as they would any other liquid cargo, with flow and head pressure
according to the characteristics of the cargo. As a point of comparison, Vinyl Chloride Monomer (VCM)
is a commonly carried liquefied gas cargo that has a density of 969 kg/m3 at -14°C (see Table 5),
compared to LCO2 density of about 1152 kg/m3 at saturation pressure for carriage as liquid (Table 7).

If a specific vessel were under consideration for LCO2 backhaul, part of the vetting process during the
pre-chartering phase would be an examination of the vessel’s pump specifications to confirm that the
particular system could adequately handle the cargo. Further discussion with cryogenic pump
manufacturer representatives indicates that pumps currently installed on liquefied gas carriers would
be capable of LCO2 service but subject to specific analysis of the particular system and conditions of
carriage.8

Safe operation of cargo pumps is dependent on maintaining the LCO2 within the temperature and
pressure range that ensures it is always above the triple point to ensure that solidification and the
resulting pump damage does not occur. Similar to the handling of liquefied gas cargos, strict attention
to temperature, pressure and the required conditions of carriage is necessary. The IGC code specifies
monitoring and control design features that would permit the operator to automatically maintain the
required parameters for safe carriage of any liquefied gas cargo.

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8 Phone conversation with Cryostar USA Sales Manager 21 March 2016
Variable frequency drive pumps to accommodate the higher density of LCO2, are recommended. Examination of the range of possible temperatures and pressures of the LCO2 flow in the system could identify the necessary cargo transfer parameters, safeguards and additional measures to ensure proper handling.

Figure 9 Typical submerged cryogenic pump (L) and deepwell pump (R) for liquefied-gas service (source: Ebara International Corporation, Wartsila Svanehoj)
2.2.4. Auxiliary Systems

Auxiliary systems for liquefied-gas carriers would include heat exchangers for cargo conditioning, re-liquefaction systems, deck tanks for cargo tank cooldown (if fitted), fuel supply systems that are integrated with the cargo system, inerting and drying systems, and other systems that may be integrated with or related to cargo transfer and handling equipment. Examination of these systems and potential operational issues would need to be identified and confirmed according to the particular vessel selected. According to discussion with LPG ship owner operators, the nature of liquefied gas carrier ship design criteria and operating philosophy provides for accommodation of a wide variety of cargos in the cryogenic liquid gases category as part of vessel technical capability drive by commercial flexibility.

Reliquefaction systems are used on many gas carriers to maintain the liquid at its required temperature and pressure. In general, re-liquefiers circulate cargo vapour using a compressor and heat exchanger arrangement to compress the vapor, lower its temperature by expansion and cooled across a heat exchanger to return it to liquid phase for re-injection into the cargo tank. If it is determined that LCO2 transport will require reliquefaction rather than controlled venting for temperature and pressure control, additional assessment of risks, limitations and safeguards would have to be conducted. There is also a requirement for examination of cargo grade change considerations, as re-liquefaction equipment would need to be completely purged of any residual cargo to avoid system damage or blockages due to solidification or deposition/sublimation.

As in other technical aspects of determining suitability for LCO2 service, specific examination of the selected ship and relevant systems is required as part of the normal vessel chartering due diligence process.

2.3. Shipping Considerations

Since the density of CO2 when carried in liquid form is greater than the density of the usual heaviest liquid gas cargo (i.e. Vinyl Chloride Monomer, VCM, 969kg/m3 @ -14°C), the filling level of the cargo tanks will be reduced. The main concern when carrying denser cargos is the additional stress that can be placed on the cargo tank and its support system. This results in a partial filling limitation that reduces the amount of cargo that can be safely carried.

Reducing the amount of volumetric capacity of the vessel can increase the cost of freight to carry the cargo. For this reason, larger vessels may be preferred, at the upper range of the Handy-size category.

A cargo of liquid CO2 of about 15,000 tonnes would occupy a volume of about 13,600m3, slightly more than half the volumetric capacity of the largest Handy-size vessels when it reaches its load line (maximum allowed capacity). This inaccessible freight capacity can represent lost revenue (in

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9 “Handy-size” is a shipping term applied to LPG vessels in the 15,000m3 – 30,000m3 capacity range
comparison to other backhaul cargos, if available) to a ship owner that could possibly command a freight premium to LCO2 shippers.

Analysis of potential freight rates for CO2 backhaul should be the subject of more detailed economic analysis when specific vessels, trade routes and potential customers are identified (see Section 3.0).

Like other liquefied gas cargos, composition and quality variation can significantly affect the safe carriage of LCO2. Suppliers must be held to minimum quality and composition standards as variations in non-condensable gases can significantly affect the properties of the gas, with risk of solidification\textsuperscript{10}. These minimum specifications would have to be agreed in the commercial arrangement between the buyer, seller and shipper. This would also be a factor in selecting suppliers to ensure that they can consistently meet the required specification.

2.3.3. Changing Cargos: Purging, Inerting and Preparation Operations

Changing cargos is part of normal, routine liquefied-gas carrier operations. Liquefied gas carriers are built with segregation capabilities to permit isolation of systems in order to carry more than one cargo at a time. They also routinely carry different cargos on different voyages according to the needs of their charterer. Liquefied gas carrier operators have developed specific procedures for safe change-over from one cargo to another based on the permitted cargos listed on the Certificate of Fitness and the particular requirements of the vessel’s cargo system.

Changing from one cryogenic liquid gas cargo to another generally involves complete discharge of the first cargo, warming and vaporizing of the un-pumpable amount left on board, then purging the remaining gas atmosphere with an on-board inert gas generator (IGG) using flue gas from the ship’s engine. Once the cargo tank and transfer piping are free of the previous cargo and fully inerted, gassing-in, cooling down and loading of the next cargo can begin.

It should be noted that the complete exchange of the cargo tank atmosphere from hydrocarbon cargo to LCO2 will result in release of additional hydrocarbons into the atmosphere. This may occur in any case as part of normal liquefied gas carrier operations when preparing for a different cargo, but the net hydrocarbon emissions should be quantified when examining a specific case.

Hydrocarbon emissions from ships is not currently explicitly regulated when conducting change of grade operations at sea, although there are regulations addressing release of cargo vapors during loading operations in port\textsuperscript{11}.

In the case of LCO2, following the specific vessel procedure and assuming that the emptying, warming, purging and inerting process was properly completed, it could be safely loaded after carriage of any liquefied gas cargo.

\textsuperscript{10} CO2 Liquid Logistics Shipping Concept (LLSC) Overall Supply Chain Optimization, Tebodin Netherlands BV Report for Vopak and Anthony Veder 21 June 2011, pg 51

\textsuperscript{11} MARPOL Annex VI, Regulation 15.7, Volatile organic compounds (VOC) This regulation shall also apply to gas carriers only if the type of loading and containment systems allow safe retention of non-methane VOCs on board or their safe return ashore.
The preparation time for changing from one cargo to another is usually specified in the vessels Gas Form C. From figure 9 below, it can be seen that the required time can be as long as 7 days for a full change of a Handy-size liquefied gas carrier. This would have a potential operational impact on loading LCO2 for backhaul as this would need to be factored in to the ship’s cargo lifting schedule and voyage economics. An evaluation of methods and procedures to reduce preparation time should be made. Depending on the criticality of contamination of CO2 by the previous cargo, it is possible that inerting time could be significantly reduced or even omitted.

**Figure 10 Excerpt from Gas Form C indicating change of cargo times (source: Evergas)**

<table>
<thead>
<tr>
<th>B15 CHANGING CARGO GRADES</th>
<th>Hours</th>
<th>Inert Gas (Air)</th>
<th>Nitrogen</th>
</tr>
</thead>
<tbody>
<tr>
<td>From Propane to Butane</td>
<td>160</td>
<td>83 000 Nm3</td>
<td>105 000 Nm3</td>
</tr>
<tr>
<td>From Propane to Butadiene</td>
<td>160</td>
<td>83 000 Nm3</td>
<td>105 000 Nm3</td>
</tr>
<tr>
<td>From Propane to Ethylene</td>
<td>160</td>
<td>83 000 Nm3</td>
<td>105 000 Nm3</td>
</tr>
<tr>
<td>From Propane to Ammonia</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>From Propane to Vinyl Chloride Monomer</td>
<td>160</td>
<td>83 000 Nm3</td>
<td>105 000 Nm3</td>
</tr>
</tbody>
</table>

### 2.4. Candidate Liquefied Gas Carriers

Based on the criteria for carriage of CO2 and the initial shipping considerations described above, a small number of existing vessels have been identified as being potentially CO2 capable based on their capacity and permitted cargos. According to information from Clarkson’s shipping database, there are approximately thirty pressurized liquefied gas carriers currently in service that could be considered suitable. (Table 8). These vessels represent part of the potential available pool from which CO2 backhaul candidates could be chosen. Further study would be needed to identify specific ships that meet the technical requirements to carry CO2 matched with trading routes that could facilitate CO2 backhaul cargos and ship owners and charterers with sufficient incentive to accept them.

**Table 8 Candidate Ships based on potential LCO2 capability listed by capacity (source: Clarkson’s)**

<table>
<thead>
<tr>
<th>Vessel Name</th>
<th>Type</th>
<th>Builder</th>
<th>Built Date</th>
<th>Capacity (cu m)</th>
<th>Tank Temp (°C)</th>
<th>Tank Pressure (kgf sq m)</th>
<th>Owner Company</th>
</tr>
</thead>
<tbody>
<tr>
<td>Donau</td>
<td>LPG Carrier</td>
<td>Meyer Werft</td>
<td>01/09/85</td>
<td>30200</td>
<td>-50</td>
<td>7.0</td>
<td>Exmar LPG BVBA</td>
</tr>
<tr>
<td>Norgas Napa</td>
<td>Ethylene/LPG</td>
<td>Zhonghua Shipyard</td>
<td>01/10/03</td>
<td>10208</td>
<td>-104</td>
<td>7.0</td>
<td>Teekay LNG Partners</td>
</tr>
<tr>
<td>Norgas Shasta</td>
<td>Ethylene/LPG</td>
<td>Zhonghua Shipyard</td>
<td>01/08/03</td>
<td>10208</td>
<td>-104</td>
<td>7.0</td>
<td>Norgas Carriers</td>
</tr>
<tr>
<td>Norgas Alameda</td>
<td>Ethylene/LPG</td>
<td>Zhonghua Shipyard</td>
<td>01/05/03</td>
<td>8556</td>
<td>-104</td>
<td>7.0</td>
<td>Norgas Carriers</td>
</tr>
<tr>
<td>Norgas Orinda</td>
<td>Ethylene/LPG</td>
<td>Zhonghua Shipyard</td>
<td>01/10/02</td>
<td>8556</td>
<td>-104</td>
<td>7.0</td>
<td>Norgas Carriers</td>
</tr>
<tr>
<td>Norgas Petaluma</td>
<td>Ethylene/LPG</td>
<td>Zhonghua Shipyard</td>
<td>01/03/03</td>
<td>8556</td>
<td>-104</td>
<td>7.0</td>
<td>GasMar AS</td>
</tr>
<tr>
<td>Norgas Sonoma</td>
<td>Ethylene/LPG</td>
<td>Zhonghua Shipyard</td>
<td>01/01/03</td>
<td>8556</td>
<td>-104</td>
<td>7.0</td>
<td>SGPC</td>
</tr>
<tr>
<td>Jemila</td>
<td>LPG Carrier</td>
<td>A.E.S.A.</td>
<td>01/03/83</td>
<td>8040</td>
<td>-48</td>
<td>8.0</td>
<td>Sonatrach Petroleum</td>
</tr>
</tbody>
</table>
Note that this is a preliminary screening and that the ships listed above are notional candidates based on capacity and cargo type. Confirmation by the ship owner of LCO2 technical capability and issuance of a Certificate of Fitness listing LCO2 as a permitted cargo would be the required next step.

As can be seen from Table 8, the cargo capacities of the listed vessels are limited, although they are larger than the currently operating dedicated LCO2 carriers (see Table 4, Yara Froya).

To operate in US waters, a specific endorsement (Subchapter O endorsement (SOE) to carry liquid CO2 would be required on the USCG issued Certificate of Compliance (COC) for ships operating in US waters under 46 CFR 153.15 (Subchapter O). The SOE and Certificate of Compliance (COC) to foreign flag vessels calling on US ports are routinely issued by USCG as long as the vessel has a valid Certificate of Fitness for LCO2.

Further study would be needed to identify specific ships and confirm that they meet the technical requirements to carry CO2, that their trading routes could facilitate CO2 backhaul cargos and that the ship owner(s) and charterers could be sufficiently incentivized to accept them.
3. LCO2 Backhaul Economics

The specific economics of LCO2 backhaul depend on a variety of factors, including but not limited to:

- The particular vessel(s) selected:
  - Volumetric capacity
  - Deadweight
  - Cargo transfer rates
- The selected trade route
- The availability of other backhaul cargos
  - more operationally convenient
  - more economically attractive
- Suitable LCO2 marine transfer facilities at load and discharge ports
- Willing sellers, buyers, shippers and carriers

Specific analysis of a particular vessel, trade route or LCO2 shipping project is beyond the scope of this report, but the framework for economic analysis based on typical shipping industry voyage economics is described below.

3.1. Methodology

Once technical capability to carry LCO2 is established, a framework to establish economic feasibility must be developed. In anticipation of the planned and projected development of the US NGL export market, multi-gas carriers would typically transport cargoes from the US to Europe or the Mideast and return empty on the ballast voyage. There may be economies earned if multi-gas carriers could also transport cargo on the ballast (or back haul) leg, thus earning the vessel owner additional revenues on an otherwise empty vessel.

The economic analysis, taking into the account the factors described above and any other identified issues would compare the cost of Base Line to Alternative Voyages:

1. Base Line Voyage – Wherein vessel transports LPG from USAC or USG load port to European or Mideast disport, returning empty (ballast leg) to the USAC or USG load port. Determine revenue and cost of round-trip.

2. Alternative Voyage – Wherein vessel transports LPG from USAC or USG load port to European or Mideast disport, then transports CO2 from European or Mideast load port to USAC or USG disport. Determine cost of round-trip, front-haul and backhaul.

3. Breakeven Analysis – The difference between the costs of the Base Line and Alternative Voyage is the breakeven point; which is the amount of revenue needed to receive for the backhaul voyage to determine economic viability.

4. Market Analysis and Conclusion – ABS Consulting to determine:
a. If there exists a sufficient market, supply and demand, of CO2, and vessel availability to support a back-haul trade.

b. Minimum revenue necessary to support the back-haul trade.

3.2. Required Data

The analysis will first need to identify various trade-routes including load and discharge ports for both LPG and CO2; i.e. transport LPG from Marcus Hook to Norway, then sail to Scotland or Rotterdam to load CO2 and transport to Houston, returning to Marcus Hook to repeat (Fig 11). Note that this voyage is hypothetical and will depend on the development of the required infrastructure and trade route opportunities.

Figure 11 Hypothetical LCO2 backhaul voyage: loading Ethane in Marcus Hook, discharging in NW Europe (red line), loading LCO2 in Rotterdam, discharging in USGC (green line) (Source: ABSC / google maps)

3.2.3. Market

a. Identify potential CO2 market:
   i. Annual supply and demand requirements.
   ii. Typical voyage size.
   iii. Frequency of voyages.
2. Client
   a. Identify Client; vessel owner or charterer.
   b. Type of contract under which vessel operates; bareboat, time charter, contract of affreightment, etc.
      i. Specifics of contract, particularly will contract allow operator back haul movements.
   c. Most current copies of all contract documents which impact ownership or right to use of the vessel, such as trust agreements, participation agreements, etc.

3. Ports
   a. Identify all potential load and disports by cargo type; LPG and CO2.
   b. Identify any port restrictions, i.e. draft, LOA, Dwt restrictions, etc.
   c. Typical and usual port costs for each port.
   d. Unusual conditions, if any, which may exist for a specific port requiring additional time and/or costs.
   e. Usual or contractual port time allowed before incurring demurrage, (generally 24 hours all-in).
   f. Standard distance between each port.

4. Vessels
   a. Based on anticipated / projected US NGL export expansion from the US to Europe and Mideast, identify all vessels currently active in this market.
   b. Vessel type and requirements
      i. Identify total fleet capable of carrying LPG and CO2.
      ii. Identify vessel particulars; volumetric capacity, deadweight, specialized cargo handling equipment capable of providing the cargo at the required temperature and pressure for the said trade.
      iii. Identify specific vessels for said trade.
      iv. Expected vessel speed, both laden and ballast.
   c. Daily Operating Costs
i. Typical daily operating costs, including crewing/manning, consumables, supply operations, catering, maintenance expenses, licensing fees, regulatory fees, classification fees, insurance, etc. of the vessel. Exclude depreciation and taxes.

d. Preparation cargo conversion time and costs

i. Identify necessary measures, such as cleaning, temperature and pressure adjustment, including associated cost and time required to prepare vessel to transform from carriage of LPG to CO2 (and back again).

e. Other costs, including social/environmental

i. Is the added distance and fuel expended to accommodate the backhaul offset by the amount of carbon captured and stored?

4. Conclusions and Recommendations

Although it is technically feasible to carry LCO2 in the liquefied gas carriers identified in Table 8, it is important to recognize that there are many challenges to be met before CO2 backhaul can be incorporated into current trading routes.

Existing LCO2 dedicated vessels are not suited for long haul, cost efficient transport of LCO2. The LCO2 capable liquefied gas carriers listed in Table 8 may not have sufficient cargo carrying capacity for cost efficient trans-Atlantic voyages.

Absent the current lack of CO2 supply, active CO2 trading markets and supporting infrastructure, the most significant challenge is to find existing or on-order ships with cargo tanks that can accommodate the higher pressure required to safely and efficiently carry CO2.

Further study to include direct surveys of ship owners with vessels operating in LPG service is recommended to identify specific ships meeting the criteria:

- Type 2G or 3G liquefied gas carrier with, or capable of being approved for, a Certificate of Fitness for liquid CO2
- Type C (pressure vessel) containment system with greater than 7 Bar g design pressure and appropriate safety margin (Note that lower design pressures may be possible if confirmed by operational evaluation)
- Tanks and cargo systems suitable for cryogenic liquid gases
- Permission from the relevant authorities to carry liquid CO2
- Sufficient cargo carrying capacity to allow competitive unit freight cost
Existing designs of Handy-size liquefied gas carriers are a close fit, but would need to be modified at the newbuilding stage with cargo tanks of sufficient design pressure to accommodate carriage of CO2.

It is possible that newbuild vessels designed for LCO2 as well as NGLs may provide a better marine transport solution as the US NGL export market and the CCS market evolves.

Liquefied gas carriers could be changed to accommodate carriage of CO2 by increasing the cargo tank design pressure. It is expected that the cost of the required modifications should be only marginally higher than for a standard liquefied gas carrier, but an evaluation of cost in relation to the specific LCO2 opportunity is recommended.

The expanding US NGL export market provides an opportunity to integrate new build ships with LCO2 capability with projected / potential CCS transport requirements. The framework for further economic analysis outlined in Section 3.0 of this report is recommended as a guide to determine the best solution.

In order for the concept to work as intended, sufficient monetary inducements to charterers to offset the daily hire rate of the vessel must be offered.

There is also an opportunity cost to be quantified depending on a number of factors:

- Cost to deviate or reposition from the load and discharge ports specified in the charter
- Charterer’s willingness to deviate from set voyage routes,
- Available backhaul cargos that are more attractive economically, operationally or logistically
- Potential for delayed or missed scheduled loading and related commercial penalties
- Cargo changeover and preparation time costs,
- Environmental impacts- hydrocarbon emissions from cargo changeover, carbon emissions offset considerations from potential CO2 venting

Current CO2 marine storage and transfer infrastructure is currently not sufficiently developed to support large scale movement of LCO2. Collaboration in the form of a joint industry project (JIP) or similar venture between CCS projects, ship owners, LPG shippers, CO2 end users, regulatory bodies and industry organizations is recommended to develop a coordinated solution incorporating marine transportation of CO2 that optimizes existing and planned transportation, storage and distribution infrastructure.
Feasibility Study of Ship-Based Transportation of CO₂

Appendix 1
Overview of Likely Legal and Regulatory Issues Associated with the Maritime Shipment of Bulk Carbon Dioxide Primarily for Use in EOR

Prepared by
University of Wyoming, School of Energy Resources
Carbon Management Institute
Overview of Likely Legal and Regulatory Issues Associated with the Maritime Shipment of Bulk Carbon Dioxide Primarily for Use in EOR

This memorandum provides an initial “issue spotting” overview of likely legal and regulatory issues associated with the maritime transportation of commodity quantities of carbon dioxide (“CO2”): (1) between and among the United Gulf Coast, the United States California Coast, northwest Europe, China, Japan and South Korea; and (2) for purposes of use in carbon dioxide-enhanced oil recovery (“CO2-EOR”), CO2-EOR with associated storage, and potentially deep saline sequestration. Likely shipping routes include: (1) northwest Europe to the United States; and (2) Far East to Indonesia or California on backhaul of LPG/ethane carriers.

Executive Summary

The contemplated commercial activities are novel and thus would be expected to raise numerous complex, time-consuming, and unanticipated legal and regulatory hurdles, not all of which may be surmountable.

Based upon our initial review, international and domestic laws and regulations fail to provide clear answers regarding how the contemplated commercial activities may be authorized, permitted, or otherwise allowed.

Given the technical similarities between liquefied CO2 and other materials being transported in bulk (e.g., LPG, LNG), analogies may be drawn that provide regulators and policymakers with comfort that the bulk maritime transport of CO2 is environmentally sound. Still, we would anticipate that the project proponents here would have to commit considerable time and resources in convincing regulators and policymakers in the relevant jurisdictions that these activities should proceed.

Analysis

I. Overview

Legal issues related to the transboundary movement of CO2 for use in EOR – or EOR storage – are novel.

Most of the literature and analyses published to date on this topic – as confirmed by our separate research -- assumes that the CO2 is being transported for storage because that is the likely scenario for the foreseeable future for the following reasons: (1) each marginal ton of captured CO2 going forward is likely to be subject to some form of climate regulation in either the exporting or importing country; (2) the marginal costs associated with implementing such a CO2 value chain are likely only supported
where an additional economic value, reflected in the “storage” activity, is liberated; (3) in areas of the world where natural CO₂ exists or is used – e.g., the Permian Basin – there is already sufficient domestic demand for the CO₂ that it is difficult to conceive of a commercial scenario where the natural CO₂ is exported; (4) evidence suggests that even natural CO₂ from the domes may come under regulation in countries such as the United States in the coming years¹; (5) even business-as-usual CO₂-EOR operations in the United States are having to face “storage” regulatory issues whether they want to or not²; and (6) post the 2015 Paris Agreement, the political climate is such that commercial proposals for the transboundary movement of “unregulated” CO₂ “merely” for EOR purposes are likely to face withering and unrelenting public opposition and scrutiny.

For these and related reasons, this memorandum draws upon legal analyses that assume, as a worst case and where relevant, that the CO₂ being transported also must be stored as a legal matter.

We recognize that a commercial case may be made for the transboundary movement of CO₂ for non-storage EOR purposes. We are aware of at least two such examples:

- **U.S. (Dakota Gasification Plant)/Canada (Weyburn).** From a climate regulatory perspective, we consider this situation to be an historic anomaly given the current political and regulatory climate surrounding these topics. The operation is likely effectively grandfathered from a CO₂ regulation point of view, plus the case could be made that the CO₂ isn’t really unregulated given the storage assessments at Weyburn.

- **Interstate Movement of CO₂ for EOR within the United States.** A robust network of interstate pipelines moves CO₂ for EOR purposes within certain regions of the United States. Those pipelines largely are regulated by the States, with a relatively minor federal role in safety standards. This pipeline network is already facing regulatory uncertainties regarding the potential introduction of additional volumes of CO₂ from anthropogenic sources, even if such sources are not currently regulated by EPA, because they could become regulated in the near future. The existence of these and related regulatory uncertainties has arguably contributed to an uncertain investment environment.

In sum, we believe that building a commercial case around the assumption that going forward CO₂ may be shipped from country to country for use in EOR without consideration of storage requirements would be legally unwise and imprudent.

The Global CCS Institute has noted that CO₂ transport touches upon different areas of law, to include the following³:

- Legal definition of CO₂: is it a waste or a commodity? Different legal consequences could stem from classifying CO₂ in either of these categories⁴;

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¹ Natural CO₂ suppliers, for example, must report under Subpart PP of the U.S. Environmental Protection Agency’s GHG Reporting Program. Normally such reporting is a precursor to emission regulation.
² For example, the source of some of the CO₂ used for EOR operations in the United States is natural gas separation plants. New natural gas separation plants and existing natural gas separation plants undergoing “major” modifications are subject to EPA’s GHG emission control regulations.

Conflicting country jurisdictions over pipeline control and management when CO₂ pipelines cross national boundaries – a situation still relevant where the bulk of the transport is via the maritime mode;

Health and safety guidelines and procedures, which need to be established or adapted from other transportation regimes in order to deal with potential risks to human health or the environment;

Liability for harm caused by accidents or leaks from CO₂ pipelines or other transport facilities;

Permitting issues;

Third-party access to the transportation network, transit rights and property rights with respect to infrastructure routes in the exporting and importing countries; and

Environmental impact assessment and planning procedures, taking into account public participation in the decision-making process and wider public perception of CCS and storage via CO₂-EOR.

Our preliminary research confirms that many of these issues remain unresolved in the arguably “easier” case of pipeline transport, let alone the maritime shipping case.

Our views in this memorandum are further informed by: (1) recent failed efforts to move fossil fuels across boundaries (i.e., the Keystone XL pipeline); (2) the lengthy political horse trading required in related contexts (i.e., the new U.S. law that enables the export of oil in return for renewable energy tax incentives and other pro-renewable policies); and (3) the challenged condition of CCS projects generally worldwide (e.g., if Germany will not allow CO₂ pipelines to be built domestically, what reason is there to believe that they will support the construction of the same infrastructure for the export of CO₂ through Norway?).

II. Transportation Considerations

a. International Maritime Transportation Conventions and Codes

The bulk shipment of liquefied CO₂ by sea would be expected to raise novel regulatory issues arising under international transportation conventions and codes because the “use of ships for transporting CO₂ across the sea is … in an embryonic stage.” In fact, “[t]here are no regulations specific to transport of

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4 In the United States, EPA has taken the position that CO₂ being “stored” is a “solid waste” for purposes of the Nation’s federal hazardous waste law and regulations. http://www3.epa.gov/epawaste/nonhaz/industrial/geo-sequester/faqs.htm.

5 IPCC Special Report on Carbon Dioxide Capture and Storage, chapter 4, p. 186 (IPCC 2005). Accord Preliminary Feasibility Study on CO₂ Carrier for Ship-based CCS, p. 4 (Global CCS Institute 2011) (hereinafter “GCCSI Study”) (“[Maritime] [t]ransportation in CCS … has not been addressed … and the necessity for ship-based CO₂ transportation does not exist”); Jung, J., CO₂ Transport Strategy for the Offshore CCS in Korea (GHGT-11 2013) (“To date, there is no ship for CO₂ transport with some exceptions for food industries”); Neele, F., Ship Transport of CO₂ – Breaking the CO₂-EOR Deadlock
CO₂ by ship and, in Europe, there are presently no specific guidelines for such transport either. And although “[n]othing in [any] of these potentially applicable conventions and codes” would imply that transportation of CO₂ would be prevented,” that outcome cannot be entirely discounted either.

Transportation considerations in this regard fall into three broad categories – i.e., is bulk liquefied CO₂ regulated by conventions and/or codes governing: (1) the bulk carriage of chemicals; (2) the bulk carriage of liquefied gases; and/or (3) atmospheric emissions of CO₂ from maritime vessels? We address each of these separately below.

i. Bulk Carriage of Chemicals

Liquefied CO₂ transported by sea is not currently specifically addressed under applicable conventions and codes pertaining to the bulk carriage of chemicals. It is likely that bulk quantities of CO₂ being transported by sea would not be regulated under such regimes but instead would be addressed as a liquefied gas, discussed separately below. Because the regulation of CO₂ as a “chemical” in transport cannot be entirely discounted, however, we discuss it here.


The IBC Code provides an international standard for the safe carriage in bulk by sea of dangerous chemicals and noxious liquid substances listed in chapter 17. To minimize the risks to ships, their crews and the environment, the IBC Code prescribes the design and construction standards of ships and the equipment they should carry, with due regard to the nature of the products involved. In December 1985, the IBC Code was extended to cover marine pollution aspects and applies to ships built after July 1, 1986.

In October 2004, IMO adopted revised MARPOL Annex II Regulations for the control of pollution by noxious liquid substances in bulk. This incorporates a four-category categorization system for noxious and liquid substances and it entered into force on January 1, 2007. Carbon dioxide is not listed under any of these regimes. However, the bulk carriage of any liquid product other than those defined as oil (subject to MARPOL Annex I) is prohibited unless the product

(9GHGT-12 2014) (“Although transportation of CO₂ by ship has been commonplace for more than 20 years, the purpose of this transportation has not been related to EOR … [and] [u]p until now, there have only been small tonnage ships (approx.. 1000 tons) for supplying CO₂ to the food industry and other relatively speaking, small scale purchasers”). Earlier this year, Norwegian company Yara International ASA announced an upgrade to its vessels used to transport CO₂ for the food and related industries. http://worldmaritimenumews.com/archives/169201/yara-adds-new-co2-ship/.


7 For background on MARPOL, see http://www.imo.org/en/About/Conventions/ListOfConventions/Pages/International-Convention-for-the-Prevention-of-Pollution-from-Ships-(MARPOL).aspx.
has been evaluated and categorized by inclusion in Chapters 17 or 18 of the IBC Code. Such an assessment may be required here.

ii. Bulk Carriage of Liquefied Gases

The “International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk” (“IGC Code”) applies to gas carriers constructed on or after July 1, 1986. Gas carriers constructed before that date should comply with the requirements of the “Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk” or the “Code for Existing Ships Carrying Liquefied Gases in Bulk.”

The purposes of these codes is to provide an international standard for the safe transport by sea in bulk of liquefied gases and certain other substances, by prescribing the design and construction standards of ships involved in such transport and the equipment they should carry so as to minimize the risk to the ship, its crew and to the environment, having regard to the nature of the products involved.

The basic philosophy is one of ship types related to the hazards of the products covered by these codes, each of which may have one or more hazard properties. A further possible hazard may arise owing to the products being transported under cryogenic (refrigerated) or pressure conditions.

Application of the IGC Code to the bulk maritime transport of liquefied CO₂ in this and related contexts has been the subject of academic papers.9 A 2011 study funded by the Global CCS Institute applied the IGC Code to the design of a liquefied CO₂ carrier and reached the following conclusions10:

The physical properties of CO₂, specifically the vapor liquid equilibrium properties of CO₂, are such that the design of a storage tank for the containment of liquid carbon dioxide is very similar to existing designs for intermediate pressure liquefied petroleum gas (LPG) containment systems. The design methodology for LPG cargo tanks is well understood and is regulated by international standards (specifically the [IGC Code]) and Classification Societies (such as DNV, BV and LRS). The design methodology employed in this study which is for the maritime transport of [liquefied] CO₂ is exactly the same as described by the IGC [C]ode and subject to Classification rules. These design rules are well proven with literally hundreds of LPG carriers operating worldwide in an industry that has an excellent safety record since the advent of LPG bulk marine transport in the early 1960s.

The 2015 Brownsort Review reached a similar conclusion11:

The review of available literature on ship transport of CO₂ shows that, while experience is limited to small scales, there is a good level of

9 See, e.g., Kokubun, N. et al., Cargo Conditions of CO₂ in Shuttle Transport by Ship (GHGT-11 2013); GCCSI Study; Brownsort Review, p. 32; Transport of CO₂ by Ship Tankers (Global CCS Institute web site, last visited Dec. 21, 2015).
10 GCCSI Study, p. 18.
11 Brownsort Review, pp. 36-37.
understanding and definition of what would be needed for scale-up to capacities relevant to CCS or CO₂-EOR. Although many publications note EOR as a potential user of ship transport, there is very little coverage of any specific requirements for EOR, it being included under general CO₂ storage considerations. This may be justified for most of a ship-based liquid CO₂ supply chain, however, there may be requirements specific to EOR at the interface between shipping and reservoir, that is, at the injection stage of the system, which have not been fully considered in the literature.

Shipping of CO₂ is most effective as a liquid at temperature and pressure conditions close to the triple point. The technology required is based on that for other cryogenic liquids such as LPG or LNG …

The proposed role for shipping in the development of CO₂-EOR … is supported by the body of literature in general. Shipping of liquid CO₂ at large scale is feasible with known technologies and can provide a transport system that is flexible in terms of space and time …. 

Despite this optimism in the literature, as well as the existence of relatively small vessels used to transport CO₂ for the food and related industries, the fact remains that carriers of a size needed to support onshore EOR operations in a third-party country have not yet been built:12

Ship size and tank is … another issue. Ships in use for commercial transport of CO₂ are only around 1000 t. Larger ships have been proposed and different designs have been proposed … In certain studies, ships up to 20,000 tons have been discussed. However, no such tankers have so far been built.

This means, at minimum, that the first ship of such size would need to clear the certification and related procedures of the IGC Code.13

iii. Atmospheric Emissions of CO₂ from Maritime Vessels

Incidental emissions of CO₂ from bulk carriers may be subject to new and evolving codes addressing greenhouse (“GHG”) emissions from vessels. The MARPOL Convention addresses air pollution and emissions from ships under Annex VI, first adopted in 1997. A revised Annex VI was adopted in 2005 and entered into force in 2010, phasing in a progressive reduction in sulfur oxides from ships and further reductions in nitrogen oxides emissions from marine engines. Amendments adopted in 2011 set mandatory measures to reduce emissions of GHGs from international shipping, with the so-called “Energy Efficiency Design Index” made mandatory for new ships, and the “Ship Energy Efficiency

13 For background on the IGC Code, see http://www.imo.org/en/OurWork/Environment/PollutionPrevention/ChemicalPollution/Pages/IGCCod.asp.
Management Plan” made a requirement for all ships. These amendments entered into force on January 1, 2013.¹⁴

Application of these requirements to incidental CO₂ emissions from bulk carriers is unclear but cannot be discounted given the novelty of the situation.


Entering into force in 1994, the United Nations Convention on the Law of the Sea (“UNCLOS”) accomplishes several tasks, including dividing the oceans into various zones and protecting the marine environment.¹⁵ Parties to UNCLOS include China, the EU, Japan and South Korea. The United States is not a party.

Application of UNCLOS to the maritime shipment of bulk CO₂ is unclear. It is most likely to apply to offshore injection and storage activities, which are not contemplated here.¹⁶ Still, the inadvertent leakage of CO₂ from loading/offloading platforms could trigger UNCLOS scrutiny, as follows¹⁷:

- UNCLOS does not expressly prohibit CCS activities, but its provisions may well have an impact where the activities are deemed to constitute pollution, which is defined in Article 1(4) as:
  
  the introduction by man, directly or indirectly, of substances or energy into the marine environment, including estuaries, which results or is likely to result in such deleterious effects as harm to living resources and marine life, hazards to human health, hindrance to marine activities, including fishing and other legitimate uses of the sea, impairment of quality for use of sea water and reduction of amenities.

- There is no conclusive opinion as to whether CCS would constitute pollution in accordance with this definition.

- UNCLOS applies to the seabed and its subsoil. However, there remains uncertainty as to whether its provisions would apply in order to regulate CCS activities undertaken beneath the subsoil.

- The right of a coastal state to exploit its Exclusive Economic Zone (“EEZ”) is, to some extent, curtailed by the provisions of Part V of UNCLOS. UNCLOS places some

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¹⁶ If offshore injection and storage activities are contemplated, additional agreements could also apply, including but not limited to: (1) the OSPAR Convention; (2) Marine Strategy Framework Directive (2008/56/EU); and (3) offshore provisions of EU Directive 2009/31/EC.

restrictions upon countries with regard to the erection of installations and structures in their EEZ. Article 56 requires states to “have due regard to the rights and duties of other States” when undertaking activities in the EEZ; while Part V prohibits the placement of installations, structures and their accompanying safety zones where they may interfere with recognized international sea lanes, which are essential to international navigation.

Under the provisions of UNCLOS, the transport of CO2 by ship or pipeline to an injection platform could be considered as dumping and subject to additional requirements. The London Convention of 1972 and the later Protocol of 1996 contain global rules and standards with regard to dumping and marine pollution.

c. The UNECE Convention on Environmental Impact Assessment in a Transboundary Context

The 1991 UNECE Convention on Environmental Impact Assessment in a Transboundary Context (“Espoo Convention”) is intended “to prevent, reduce and control significant adverse transboundary environmental impact from proposed activities.”\(^\text{18}\) The Convention requires states to carry out an environmental impact assessment (“EIA”) for all activities listed in Appendix I which are “likely to cause significant adverse transboundary impact” in another state. The EIA, which is defined as a “national procedure for evaluating the likely impact of a proposed activity on the environment,”, must be carried out before any decision to authorize or undertake the proposed activity and must include a series of elements listed in Appendix II (a description of the activity, of reasonable alternatives, of the environment likely to be affected, of the potential impacts and of mitigation measures to minimize the impact, etc.). The state of origin must also ensure that affected states are notified of the proposed activity.

Appendix I includes, among other things, oil refineries, coal gasification plants, certain large thermal power stations, large diameter oil and gas pipelines, trading ports, waste disposal installations for incineration, chemical treatment or landfill of toxic and dangerous wastes, offshore hydrocarbon production and major storage facilities for petroleum, petrochemical and chemical products. Any of the concerned states can also convene discussions on whether other proposed activities, not listed in Appendix I, are likely to cause a significant adverse transboundary impact and should be treated as if they were listed (subject to the agreement of all the states). Guidance on criteria to be taken into account in determining significant adverse impact is given in Appendix III (size of the activity, proximity to areas of specialized environmental sensitivity or importance, activities with particularly complex and potentially adverse effects, etc.).

The EU and many European countries individually are parties. The United States is a signatory but has not ratified it.\(^\text{19}\)

Application of the Espoo Convention to, for example, bulk CO2 loading/unloading facilities offshore EU is unclear.


d. **International Maritime Shipping Requirements**

The bulk maritime shipment of liquefied CO\textsubscript{2} is subject to the International Maritime Dangerous Goods (“IMDG”) Code, which establishes standards for packing, marking, labeling, documentation, stowage, quantity limitations, exceptions and notifications for preventing pollution by harmful substances. Carbon dioxide is classified under: (1) UN1013 with a proper shipping name of “Carbon Dioxide”; and/or (2) UN2187 with a proper shipping name of “Carbon Dioxide, refrigerated liquid.” The latter would almost certainly apply in this situation. Its hazard class is 2.2 (Non-Flammable/Non-Toxic Gas).

Since EOR-scale quantities of CO\textsubscript{2} are not currently being shipped by sea, it is possible that authorities implementing the IMDG Code would require that new hazard assessments be conducted.

e. **International CCS/CCUS-Related Codes/Standards**

ISO, through Technical Committee 265 (“TC265”), is currently developing the world’s first technical standards for CCS and storage via CO\textsubscript{2}-EOR.\(^{20}\) The work is divided by topic among Working Groups (“WG”) with two WG’s of particular relevance here: (1) WG2/Transportation; and (2) WG6/CO\textsubscript{2}-EOR Storage\(^{21}\). TC265 should conclude its initial work by 2017-2018.

WG2/Transportation is primarily focused on pipeline transportation. We nonetheless would encourage maritime interests to get involved in the process as the scope of the standard may change over time.

WG6/CO\textsubscript{2}-EOR Storage also should be of relevance to parties interested in future cross-border CO\textsubscript{2}-EOR transactions as the standard that emerges from this process should facilitate these types of commercial activities where incidental storage is claimed or is required by domestic law or regulation.

f. **Non-Maritime Modes of Transportation**

The movement of CO\textsubscript{2} by non-maritime modes of transportation (e.g., pipeline, rail, road, barge) separately would be regulated by: (1) international/multilateral transportation codes; and (2) domestic transportation laws and regulations in each country. Among the former are: (1) the European Agreement Concerning the International Carriage of Dangerous Goods by Road (the so-called “ADR”)\(^{22}\); (2) the European Agreement Concerning the International Carriage of Dangerous Goods by Rail (the so-called “RID”)\(^{23}\); and (3) the European Agreement Concerning the International Carriage of Dangerous Goods by Inland Waterway (the so-called “ADN”)\(^{24}\). Comparable dangerous goods/hazardous materials transportation regulations exist in most countries.

While we do not envision issues per se arising under these non-maritime transportation regulatory regimes, depending upon the quantities of CO\textsubscript{2} being transported the applicable codes and/or regulations may require that additional risk assessments, hazard classifications and similar steps be performed before the specific mode of transportation is authorized.

\(^{20}\) For background on TC265, see [http://www.iso.org/iso/iso_technical_committee?commid=648607](http://www.iso.org/iso/iso_technical_committee?commid=648607).

\(^{21}\) The author of this memorandum is the chair of WG6/CO\textsubscript{2}-EOR Storage.

\(^{22}\) [http://www.unece.org/trans/danger/publi/adr/adr_e.html](http://www.unece.org/trans/danger/publi/adr/adr_e.html).


\(^{24}\) [http://www.unece.org/trans/danger/publi/adn/adn_e.html](http://www.unece.org/trans/danger/publi/adn/adn_e.html).
III. Import/Export Considerations

a. Preparing CO₂ for Transport & Onshore/Offshore Loading/Unloading

Numerous steps are required to transport CO₂, each of which would be expected to raise a host of novel (as this has not been done before for bulk CO₂) and potentially burdensome and time-consuming permitting considerations under the relevant laws and regulations of each country. These steps include:

✓ **Liquefaction.** It is assumed that the CO₂ will be liquefied prior to transport.²⁵ Using LNG export terminals in the United States as an example, permitting of such facilities triggers numerous federal, State and local permitting and related approvals. These approvals include, but are not limited to: (1) air permits for criteria pollutants; (2) GHG permits (to include the potential use of CO₂-EOR as a Best Available Control Technology for CO₂); (3) water permits; (4) zoning; (5) climate impact assessments under the National Environmental Policy Act; (6) State and local approvals for linear infrastructure; (7) Endangered Species Act assessments; (8) fish and mammal assessments; (9) historic assessments; (10) safety plans & assessments; and (11) approvals by the U.S. Coast Guard.

A 2011 assessment focused on Japan identified the following domestic laws and regulations that could be triggered by the proposed construction of this type of facility in that country: (1) Marine Pollution Prevention Law; (2) High Pressure Gas Safety Act; (3) Ship Safety Act; (4) Industrial Safety and Health Act; (5) Ports and Harbors Act; (6) Act on Port Regulations; (7) Coast Act; (8) Maritime Traffic Safety Act; (9) Act on Development of Fishing Ports and Grounds; (10) Act on the Protection of Fishery Resources; (11) Marine Resources Development Promotion Act; (12) Fishery Act; (13) Mining Law; and (14) Mine Safety Act.²⁶

✓ **Intermediate Storage at Loading Point.** CO₂ capture and liquefaction are continuous processes, whereas ship transport of liquefied CO₂ is a discrete, batch process. Hence, “there is a need to provide buffer storage holding at least the volume of a ship.”²⁷ Based on our preliminary review of laws and regulations in the subject jurisdictions, this activity is not specifically regulated because it has not yet occurred as a commercial endeavor. It is likely not exempt from regulation, either. Permitting this activity would thus raise issues of first impression in most, if not all, countries.

✓ **Ship Loading.** The precise manner in which CO₂ would be loaded is unclear.²⁸ Various ideas have been proposed²⁹:

As there could be various means of CO₂ transport from capture points to [the loading] terminal, all … means of

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²⁵ *Brownsort Review*, p. 16.
²⁶ *GCCSI Study*, pp. 89-90.
²⁷ *Brownsort Review*, p. 17.
²⁸ *Brownsort Review*, p. 17; *see also GCCSI Study*, which assumed a hypothetical, detailed CO₂ loading system.
²⁹ *Transport of CO₂ by Ship Tankers* (Global CCS Institute web site, last visited Dec. 21, 2015).
transport must converge at the loading terminal … Considering that there could be barriers towards accumulating huge stocks of CO\(_2\) near populated areas, a transition station, such as a Floating Production Storage and Loading (FPSL) Vessel, can be provided in order to provide a safe distance between the CO\(_2\) temporary storage and landing area and the shore. This concept is actually adopted from the currently used Floating Production, Storage and Offloading (FPSO) vessel in the oil and gas industry. The FPSO is a type of floating tank system equipped with all necessary facilities and designed to take all the oil and gas for offloading onto waiting tankers.

Based on our preliminary review of laws and regulations in the subject jurisdictions, this activity is not specifically regulated because it has not yet occurred as a commercial endeavor. It is likely not exempt from regulation, either. Permitting this activity would thus raise issues of first impression in most, if not all, countries similar to those discussed above for “Intermediate Storage at Loading Point.”

✓ **Ship Offloading.** Based upon a relevant 2015 literature review, most “publications … assume offshore unloading to an injection well via some form of single point mooring (SPM) system to either a platform or a subsea wellhead connection.”\(^{30}\) Offloading to shore is also a possibility.

Based on our preliminary review of laws and regulations in the subject jurisdictions, this activity is not specifically regulated because it has not yet occurred as a commercial endeavor. It is likely not exempt from regulation, either. Permitting this activity would thus raise issues of first impression in most, if not all, countries similar to those discussed above for “Intermediate Storage at Loading Point.”\(^{31}\)

All of the above assumes, of course, that technical standards exist for the construction of each type of infrastructure in the first instance.

b. **Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal**

Adopted in 1989, the Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal (“Basel Convention”) endeavors to accomplish the following:

✓ The reduction of hazardous waste generation and the promotion of environmentally sound management of hazardous wastes, wherever their place of disposal;

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\(^{30}\) *Brownsort Review*, p. 21; see also *GCCSI Study*, which assumed a hypothetical, detailed CO\(_2\) unloading system.

\(^{31}\) *Transport of CO\(_2\) by Ship Tankers* (Global CCS Institute web site, last visited Dec. 21, 2015). *Accord Neele, F.*, *Ship Transport of CO\(_2\) – Breaking the CO\(_2\)-EOR Deadlock* (“Unloading CO\(_2\) in open waters is a particular challenge when it comes to [EOR] … If introducing CO\(_2\) to an offshore oil field which is not already prepared to receive the CO\(_2\), this would require reconstruction of the platform and shut down of oil production for a prolonged period of time”) (thereafter proposing technical solutions).
The restriction of transboundary movements of hazardous wastes except where it is perceived to be in accordance with the principles of environmentally sound management; and

A regulatory system applying to cases where transboundary movements are permissible.

Numerous countries/jurisdictions relevant here are parties to the Basel Convention, including China, the European Union, Japan and South Korea. The United States has signed the Basel Convention but not yet ratified it. For this reason, the United States cannot participate in waste transfers with Basel Convention parties without a separate and equivalent bilateral or multilateral agreement. The United States has entered into several bilateral agreements and one multilateral agreement. The United States currently maintains a multilateral agreement with the members of the OECD, for example, governing transboundary movements of waste for recovery purposes. In addition, the United States has established two bilateral agreements, with Canada and Mexico, for importing and exporting hazardous waste. Finally, Costa Rica, Malaysia and the Philippines have entered into separate agreements with the United States. Under these three agreements, the United States may receive waste from Costa Rica, Malaysia, and the Philippines but may not export waste to these countries. EPA regulates these activities for the United States.

Application of the Basel Convention would turn on whether applicable countries deemed bulk CO₂ being transported for EOR to be a waste within the meaning of the agreement. As previously noted, the United States (via EPA) has taken the position that CO₂ being “stored” geologically is a “solid waste” and could be a “hazardous waste” in some circumstances.

Based upon our initial research, the issue of the classification of bulk CO₂ being shipped for EOR under the Basel Convention is unresolved and thus would be a matter of first impression for commercial operators and countries undertaking the activities. So far, the only clarifications on this point have been provided by the amendment to Article 6 of the London Protocol on the export of waste and the amendments to EU waste legislation made by the EU Directive on geological storage of carbon dioxide, application of which in this context are unclear.

With respect to this situation, the Global CCS Institute has stated:

Until there is an international consensus on the classification of CO₂ for geological storage, the effect of [the Basel Convention] upon CO₂

transport will remain uncertain … The Intergovernmental Panel on
Climate Change … has stated that CO₂ is unlikely to fall within the scope
of the provisions of [the Basel Convention], unless CO₂ is mixed with
other prohibited substances. Nevertheless, in the absence of clarification
on this point, there will continue to be uncertainty about the legal status of
CO₂ and the applicability of international agreements restricting
international transport of hazardous wastes.

We agree with these sentiments.

IV. Domestic Environmental, Energy & Related Laws in Each Jurisdiction

a. Offshore Infrastructure

Depending on the precise offshore infrastructure being proposed and its location, domestic
environmental and oil & gas laws and regulations would have to be satisfied. We would need more
information about the offshore infrastructure to conduct this analysis. Since these facilities would be
novel, we would expect permitting and compliance to be time-consuming and potentially complicated in
each country.

b. Onshore Infrastructure

Depending on the precise onshore infrastructure being proposed and its location, domestic
environmental and oil & gas laws and regulations would have to be satisfied. We would need more
information about the offshore infrastructure to conduct this analysis. Since these facilities would be
novel (except, perhaps, CO₂ pipelines in the United States), we would expect permitting and compliance
to be time-consuming and potentially complicated in each country.

c. Domestic CO₂-EOR Regulations

Each importing country presumably would need to have separate regulations regarding the use of CO₂
for EOR, whether storage is claimed or not. Such regulations exist in the United States. They do not,
however, in all other countries under consideration here. For example, China does not have domestic
CO₂-EOR regulations. Such regulations would presumably have to be implemented before CO₂ could be
imported into that country for that purpose.

V. Effective Prohibitions for Political Reasons

We believe it highly unlikely that the State of California would allow – for the foreseeable future at least
– the import or export of CO₂ for EOR due to the climate change regulatory environmental in that
jurisdiction. Further, California currently lacks laws and regulations governing the activity, which does
not squarely fit within the state’s primary climate regulatory programs: (1) cap-and-trade under AB32;
and (2) the Low Carbon Fuel Standard.

The California Air Resources Board is currently in the midst of developing protocols and regulations
regarding CCS and storage via EOR. Those efforts are supposed to conclude by late 2017, with public
hearings beginning in early 2016. These efforts are unlikely to address import/export scenarios.
VI. International/Multilateral Climate Considerations

The following scenarios would only potentially apply where the CO₂ being transported was subject to a GHG emissions control requirement in either the country of import and/or export. For the reasons stated above, we below that assumption would apply here.

a. 2015 Paris Agreement

The 2015 Paris Agreement, slated to take effect in 2020 upon acceptance by the requisite number (and size) of parties, includes in Article 6 a framework for international emissions trading.\(^{38}\) It is too early to assess if and how that framework would enable cross-bounder emissions trading in the context of CO₂-EOR. The implementing procedures will be issued in the years ahead. Further, the countries participating in the CO₂ transaction would need to agree to that approach – and we note that the United States, in its INDC, indicated that it did “not intend to utilize international market mechanisms to implement its 2025 target.”\(^{39}\)

If the Kyoto Protocol’s Clean Development Mechanism (“CDM”) may be used a model, we anticipate that post-2020 CCUS-based projects should be eligible to monetize or otherwise take credit for applicable emission reductions under the Paris Agreement. Doing so, however, is not anticipated to be easy as, for example, comparable GHG regulatory regimes likely would have to be in place in both the CO₂ exporting and CO₂ importing countries. It is conceivable that the ISO CCUS standards currently under development may facilitate such transactions.

b. Kyoto Protocol

We do not believe that the Kyoto Protocol, which is currently slated to lapse in 2020 when it is replaced by the 2015 Paris Agreement, is a relevant consideration given that the commercial activities under consideration here are likely to take place in 2020 or later.

In the event that CO₂ shipments were to occur prior to 2020, application of the Kyoto Protocol to the transactions contemplated here would be subject to substantial legal uncertainty despite the fact that the CDM Executive Board recognized CCS/EOR-based projects as potentially eligible offset projects. We based this conclusion on: (1) the Kyoto Protocol’s numerous and well-documented implementation struggles; (2) declining country participation in the Second Commitment Period; (3) lack of robust CCS/EOR-storage implementation regulations in nearly all countries (with the potential exception of the United States); and (4) general skepticism about the technologies within the Kyoto Protocol’s administering bodies.

In a 2012 staff paper prepared under the auspices of the UNFCCC’s Subsidiary Body for Scientific and Technological Advice, the authors outlined numerous legal, regulatory and policy issues that would have to be resolved before transboundary CCS projects could be recognized under any of the Kyoto Protocol’s mechanisms, including the CDM.\(^{40}\) To the best of our knowledge, none of the recommendations has been implemented.

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38 *Paris Agreement*, art. 6 (FCCC/CP/2015/L.9/Rev.1).
39 [http://www4.unfccc.int/submissions/INDC/Published%20Documents/United%20States%20of%20America/1/U.S.%20Cover%20Note%20INDC%20and%20Accompanying%20Information.pdf](http://www4.unfccc.int/submissions/INDC/Published%20Documents/United%20States%20of%20America/1/U.S.%20Cover%20Note%20INDC%20and%20Accompanying%20Information.pdf).
c. **EU-ETS**

Similar to the status of CCS/EOR storage under the Kyoto Protocol, the status of the same technologies under the EU-ETS remains subject to substantial uncertainties, despite the existence of the EU Directive on geologic storage. Numerous commentators have noted that the EU-ETS has failed to support the development of domestic CO₂ storage industries, let alone enable CO₂ import/export markets for similar activities elsewhere. The Global CCS Institute has published recommendations regarding how the EU-ETS could be reformed post-2020 to enable CCS/EOR storage. Unless and until such reforms are implemented, we are pessimistic that the activities contemplated here would ever be recognized under or authorized by the EU-ETS.

Regards,

Kipp Coddington  
Director

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