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Optimizing Offshore CO_2 Transport Pathways: A Decision-Support Framework for Multimodal CO_2 Transport in the Texas Gulf Coast

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by

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Dedication

To my parents, who taught us that the greatest inheritance is not what we leave behind, but what we place within those who come after us.

You believed deeply in the transformative power of education and, through your sacrifices, gave your children an inheritance no one could ever take away. You taught us that knowledge, integrity, perseverance, and compassion would endure long after material possessions had faded. Every opportunity my siblings and I have been given, every classroom we have entered, and every milestone we have reached bears the imprint of your faith in us.

Daddy, you taught me that honest work is its own reward. Mummy, you showed me that true strength is often quiet, steadfast, and enduring. Together, you taught us to believe that no dream was too distant if we were willing to work for it, and that education was one of the greatest gifts a parent could give a child.

Neither of you lived to see where those sacrifices would lead, but this thesis, together with the lives your children have built, is part of the legacy you created through the lives you chose to invest in. It stands as evidence that what you planted continues to bear fruit. I hope this work honors your faith in us and reflects, in some small measure, the values by which you raised us.

And to my son, Adekunle, whose arrival reminded me that strength often reveals itself only when it is needed most.

Completing this thesis while becoming your mother has been one of the greatest privileges of my life. You have already taught me more about courage, perseverance, and purpose than you will ever know. My greatest hope is that, just as I inherited a love of learning, resilience, and faith from those who came before me, you too will inherit those same gifts, and know that they are given with all the love your grandparents gave to me, and all the love I have for you.

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I owe a special debt of gratitude to Ramon Gil-Egui, who has been a constant source of guidance and support throughout this research and my time at GCCC. Ramon was instrumental in bringing me to the Center and became the person I worked with most closely as this thesis took shape. He helped me think through the research's evolution, from its shifting scope to the development of the transport framework, stakeholder engagement, and the practical regulatory and infrastructure considerations that became central to the work. His door was always open to questions, ideas, and the many conversations that helped me work through what this thesis was becoming. I am deeply grateful for his mentorship, patience, confidence in me, and the consistency of his support throughout this journey. I am equally grateful for the friendship that grew out of that mentorship, which I hope will continue long after this thesis is finished.

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Abstract

Optimizing Offshore CO_2 Transport Pathways: A Decision-Support Framework for Multimodal CO_2 Transport in the Texas Gulf Coast

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The University of Texas at Austin, 2026

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As carbon capture and storage (CCS) deployment expands along the Texas Gulf Coast, selecting a cost-effective and operationally feasible CO_2 transport strategy remains a persistent planning challenge. This is particularly true where distributed emission sources must be connected to offshore storage through some combination of pipeline, marine, and feeder transport modes. Existing decision-support tools largely optimize pipeline networks once a transport mode has already been chosen. The prior question, which mode or combination of modes is appropriate for a given set of conditions, remains comparatively underexamined, especially at a scale specific to Gulf Coast geography and regulatory structure.

This thesis develops a techno-economic, threshold-based decision-support framework for evaluating CO_2 transport strategies from onshore emission sources in the Houston, Beaumont, and Corpus Christi industrial clusters to offshore storage in the Corsair Trough. It integrates GIS-based spatial analysis, a verified capital and operating cost model, and a regulatory risk mechanism that applies a cost-affecting contingency rather than treating permitting as a peripheral consideration. This distinguishes the approach from network-optimization tools that do not account for regulatory or spatial risk. The framework also models hybrid, multi-segment pathways connecting feeder modes to a shared transfer hub, informed by real precedent for third-party shared marine terminal infrastructure already operating on the Houston Ship Channel.

Applied to a set of representative Gulf Coast scenarios, the framework finds that requalified existing pipeline is least-cost across every scenario evaluated, at the relatively short distances and moderate volumes characteristic of the region; marine transport does not become competitive until distances well beyond this study's Gulf Coast scenarios, consistent with an international comparison presented in the concluding chapter. Project duration affects the magnitude of pipeline's cost advantage, since pipeline's capital cost declines more steeply with duration than marine transport's does, but does not change which mode is preferred within the range evaluated. This finding is consistent across two storage-target configurations within the Corsair Trough: the least-cost mode is unchanged in all eight scenarios tested regardless of configuration, though the cost magnitude differs with the shorter offshore distance one configuration offers.

The analysis further identifies a Gulf Coast-specific structural cost factor, arising from Jones Act construction and crewing requirements for domestic maritime transport, that is not captured in the international CO_2 shipping literature most often cited in prior work: this premium raises marine transport cost specifically, shifting the pipeline-marine crossover distance further out than international studies would suggest and making pipeline's cost advantage within the United States stronger than a direct application of that literature implies.

A supplementary analysis of shared-hub cost allocation across multiple nearby emitters demonstrates a real, though bounded, cost advantage from aggregation. A parameter sensitivity analysis further finds that the regional variability of pipeline construction cost, not any marine-side cost parameter, has by far the largest effect on where the pipeline-ship crossover distance falls, identifying a specific, concrete priority for future work rather than a general call for more precise cost data. A geographic robustness check applies the same framework to real facilities and storage targets in Louisiana, Alabama, and Florida: pipeline's advantage holds broadly beyond the Texas corridor evaluated in the primary scenarios, including at a combined aggregated volume of nearly 12 million tonnes per year, and the one identified case where marine transport is actually used instead of pipeline is explained by the complete absence of a pipeline option in that location, not by cost.

This work contributes a transparent, independently verified decision-support tool; a structured characterization of transfer hub ownership, operation, and permitting models; and a system-level methodology for evaluating multimodal CO_2 transport strategies, directly applicable to Gulf Coast infrastructure planning and, with adaptation, to other coastal CCS deployment contexts.

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CHAPTER 1: INTRODUCTION

This thesis evaluates several distinct CO_2 transport modes, introduced here and referred to consistently throughout. Figures 1.1a and 1.1b orient the reader to these modes before the detailed discussion that follows. Primary, long-haul modes- pipeline, barge, and ship- carry CO_2 over the majority of the transport distance to offshore storage. Feeder modes- truck, rail, a smaller local pipeline segment, and barge at feeder scale- are used only to move CO_2 from an emission source to a shared transfer hub in hybrid, multi-segment pathways; a single-mode pathway, evaluated as the primary comparison throughout this thesis, connects the emission source directly to storage without a feeder segment or transfer hub.

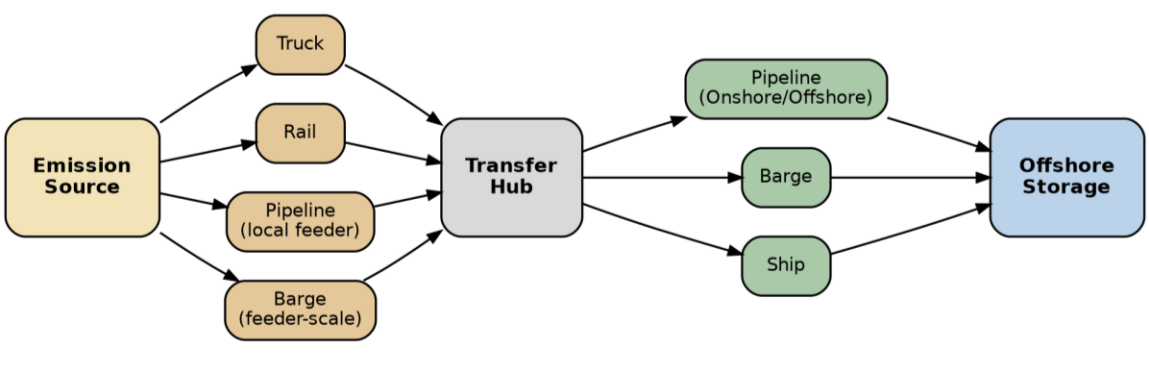

Figure 1.1a. CO_2 transport modes evaluated in this framework: the hybrid pathway.

Feeder modes (truck, rail, local pipeline, and smaller-scale barge) connect an emission source to a shared transfer hub; primary modes (pipeline, barge, ship) then carry CO_2 over the majority of the distance to offshore storage. Barge and pipeline can serve either role depending on scale and route; truck and rail serve only as feeders.

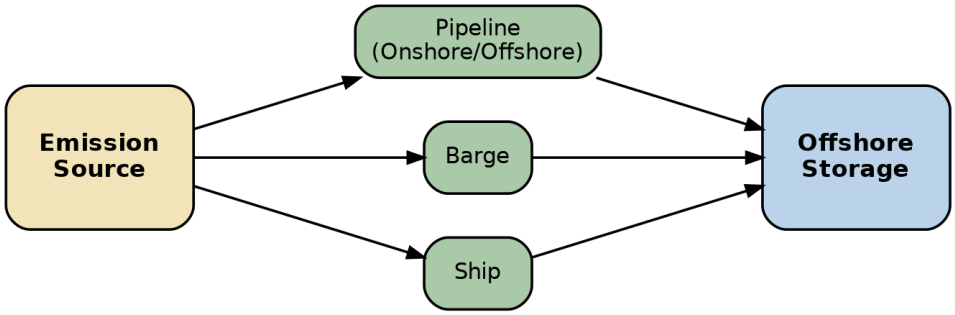

Figure 1.1b. CO_2 transport modes evaluated in this framework: the direct pathway.

Where a facility is large enough to justify its own dedicated connection, an emission source may connect directly to a primary mode, pipeline, barge, or ship, without a feeder segment or transfer hub.

1.1 Background and Context

1.1.1 Climate Change and the Role of Carbon Capture and Storage

Anthropogenic climate change is driven primarily by the accumulation of greenhouse gases in the atmosphere, with carbon dioxide (CO_2) representing the largest share of global emissions. Current estimates place annual CO_2 emissions from energy and industrial processes at over 35 gigatonnes, reflecting continued dependence on fossil-fuel-based systems and carbon-intensive industrial activity (IPCC, 2022; IEA, 2023). Stabilizing global temperatures requires rapid and sustained reductions in these emissions, alongside the deployment of technologies to address residual and unavoidable sources.

A significant portion of global emissions originates from sectors that are inherently difficult to decarbonize through electrification alone. These include cement production, iron and steel manufacturing, refining, and petrochemical processing, where process emissions are embedded in chemical transformations rather than energy use. In such cases, even complete substitution of energy inputs with low-carbon electricity does not eliminate CO_2 generation. As a result, carbon capture and storage has emerged as a necessary component of mitigation pathways to achieve net-zero emissions at the system level (IPCC, 2022; Global CCS Institute, 2022).

Carbon capture and storage comprises three primary components: the capture of CO_2 at point sources, the transport of CO_2 to suitable storage locations, and the long-term sequestration of CO_2 in geologic formations. Integrated assessments consistently show that excluding CCS from mitigation portfolios significantly increases the overall cost of achieving climate targets, particularly in scenarios with continued industrial activity and limited availability of alternative process technologies (IPCC, 2022; IEA, Net Zero Roadmap: 2023 Update, 2023). In addition to enabling emissions reductions in existing industries, CCS supports the development of negative-emissions technologies, such as bioenergy with carbon capture and storage, further reinforcing its role in long-term climate strategies.

While capture and storage technologies are often emphasized in CCS discussions, the transport component is central to determining whether these systems can be implemented at scale. CO_2 must be transported from geographically dispersed emission sources to storage sites, often located far from industrial centers, including offshore geologic formations. The scale of future CCS deployment implies

the need for extensive transport networks capable of handling hundreds of millions to billions of tonnes of CO_2 annually under reliable and cost-effective operating conditions (IEA, CCUS Policies and Business Models, 2023; Global CCS Institute, 2022).

Historically, CO_2 transport has been dominated by pipeline systems, particularly in North America for enhanced oil recovery operations. Approximately 5,300 miles of CO_2 pipelines currently operate in the United States, concentrated in Texas, New Mexico, Wyoming, Oklahoma, Louisiana, North Dakota, Mississippi, and Colorado, transporting roughly 80 million tonnes of CO_2 annually, nearly all for enhanced oil recovery (Congressional Research Service, 2025; ClearPath, 2025). These systems demonstrate that large-scale CO_2 transport is technically feasible and can be operated safely over long distances. However, the transition from dedicated pipeline systems serving individual projects to integrated networks serving multiple emitters and storage sites introduces new challenges. These include high upfront capital requirements, long permitting timelines, and the need to coordinate infrastructure development across multiple stakeholders and jurisdictions (IEAGHG, 2013; Global CCS Institute, 2022).

These challenges are amplified in coastal regions such as the U.S. Gulf Coast, where the spatial distribution of emissions, the presence of sensitive shoreline environments, and the need to access offshore storage sites create additional layers of complexity. Transport pathways must navigate shoreline crossings, port infrastructure constraints, and overlapping regulatory frameworks governing onshore, nearshore, and offshore activities. As a result, the design of CO_2 transport systems in these regions cannot rely solely on conventional pipeline development approaches.

Taken together, these factors indicate that the role of CO_2 transport extends beyond a supporting function within the CCS value chain. Instead, transport infrastructure becomes a central determinant of system feasibility, influencing not only cost but also deployment timelines, regulatory risk, and overall system configuration, thus creating a need for transport strategies that are flexible, scalable, and responsive to regional constraints, particularly in emerging CCS hubs such as the Gulf Coast.

1.1.2 CO_2 Transport in the CCS Value Chain

Transport is the physical and operational link between capture and storage: limitations in transport infrastructure can constrain the viability of an otherwise technically feasible capture and storage project, regardless of how well either endpoint performs on its own (IPCC, 2005; IEAGHG, 2013). A defining

characteristic of CCS systems is the spatial mismatch this creates. Industrial facilities are typically located near existing infrastructure, population centers, and feedstock supply chains. In contrast, suitable geologic storage formations are often located offshore or in regions removed from major emission clusters. This geographic separation requires transport networks capable of aggregating CO_2 from multiple sources and delivering it to centralized storage sites, evolving as deployment scales from simple point-to-point connections into integrated systems accommodating multiple emitters, shared infrastructure, and phased expansion over time (Middleton & Bielicki, 2009; Global CCS Institute, 2022).

The physical properties of CO_2 itself further shape transport requirements. For efficiency, CO_2 is transported in a dense phase rather than as an ordinary gas, requiring compression to elevated pressure and control of temperature and impurities to avoid phase instability and corrosion (IPCC, 2005; IEAGHG, 2013). The specific pressure and temperature combination used, however, differs by mode, and this difference is a central reason no single transport mode dominates every context; Section 1.1.3 and Section 1.1.4 address pipeline and marine transport in turn, including how each handles this requirement differently.

1.1.3 Pipeline Transport: Capabilities and Constraints

Pipeline systems have historically formed the backbone of large-scale CO_2 transport, particularly in North America, where extensive networks support enhanced oil recovery operations; existing U.S. CO_2 pipeline networks span thousands of kilometers, providing a practical foundation for understanding the technical and operational requirements of large-scale transport (Global CCS Institute, 2022; IEAGHG, 2013). Pipeline's primary advantage is its ability to handle high volumes of CO_2 continuously over extended periods: once constructed, a pipeline offers relatively low operating cost per unit transported, particularly at high utilization, enabling economies of scale that are difficult to achieve with alternative transport modes (Middleton & Bielicki, 2009; Knoope et al., 2013). CO_2 pipelines are typically designed to operate in a dense or supercritical phase, requiring compression to high pressure and careful control of temperature and impurities, since water or other contaminants can cause corrosion; pipeline design must account for material selection, fracture control, and pressure management, particularly over long distances where pressure drops and recompression may be required (IPCC, 2005; IEAGHG, 2013; Johnsen et al., 2011).

Despite these advantages, pipeline systems present constraints that can limit their applicability in emerging CCS contexts. High upfront capital cost, further influenced by route-specific factors such as terrain, land use, and environmental sensitivity, can significantly increase project complexity and expense (Knoope et al., 2013; Global CCS Institute, 2022). Permitting and regulatory processes represent an additional source of uncertainty and delay, and pipeline economic viability depends on sustained throughput and long operational lifetimes, both of which are difficult to guarantee during early-phase deployment when volumes are uncertain and infrastructure networks are not yet established (Global CCS Institute, 2022). These characteristics motivate the alternative considered next.

1.1.4 Marine Transport: Emerging Role in CCS

Marine transport, as the term is used in this thesis, includes both ship or barge vessels moving CO_2 between ports and offshore pipeline segments extending from shore to an offshore storage target; offshore pipeline shares onshore pipeline's phase and compression requirements but introduces distinct considerations of its own, including subsea construction, marine permitting, and a different regulatory jurisdiction, addressed further in Section 1.1.5 and Section 2.6. Vessel-based marine transport is increasingly recognized as a viable alternative or complement to pipeline transport, gaining attention for its flexibility in connecting geographically dispersed emission sources to centralized storage, particularly where fixed pipeline infrastructure is difficult to permit or economically justify at an early stage of deployment (IEAGHG, 2017; IEA, CCUS Policies and Business Models, 2023). Unlike a pipeline, which requires substantial upfront capital investment and a long lead time before any capacity exists, a vessel-based system can be deployed incrementally, expanding capacity in response to demand rather than requiring the full network to be built before any CO_2 moves.

CO_2 transported by ship or barge is handled as a refrigerated liquid at moderate pressure, in contrast to the high-pressure, ambient-temperature-adjacent supercritical phase used in pipelines; this handled-as-refrigerated-liquid, high-pressure/low-temperature distinction is the central engineering difference between the two approaches, driving essentially all of vessel transport's distinct requirements, cryogenic or near-cryogenic storage, insulation to manage heat ingress, and careful pressure and temperature control during loading, transit, and unloading, in turn shaping vessel design, terminal infrastructure, and transfer operations, and introducing energy and operational costs beyond what pipeline transport incurs (Aspelund et al., 2006; IEAGHG, 2017). Vessel capacity, turnaround time, and loading and unloading rates directly

affect system throughput and cost efficiency, and in inland and nearshore environments, draft limitations can further constrain vessel size and therefore payload per trip; this is not a consideration this thesis models explicitly, since the framework developed here evaluates cost as a function of distance, volume, and duration rather than vessel-specific routing constraints, a scope limitation discussed further in Section 5.4. These constraints are particularly relevant in regions such as the U.S. Gulf Coast, where navigation channels, river systems, and port infrastructure impose physical limits on vessel dimensions and payload, requiring system design to account for water depth and channel width alongside nominal vessel capacity, and supported by a network of terminal, storage, and port infrastructure of the kind already operating for other liquefied-gas cargoes along the Gulf Coast (Blue Sky Maritime Coalition, 2024). Weighed together, vessel-based transport's central advantage is deployment flexibility without large fixed upfront investment; its central disadvantage is a real, ongoing operational cost and complexity burden, cryogenic handling, port dependency, and per-trip capacity limits that a mature pipeline network does not carry once built (Aspelund et al., 2006; IEAGHG, 2017; Roussanaly et al., 2021).

The Northern Lights project in Norway illustrates this vessel-based approach at commercial scale: CO_2 captured at industrial sites across Europe is shipped to an onshore receiving terminal, then moved by a 100-kilometer subsea pipeline to permanent offshore storage, a hybrid marine-to-pipeline pathway of exactly the kind this thesis evaluates, currently operating at 1.5 million tonnes of CO_2 per year with an approved expansion to 5 million tonnes. Figure 1.2 illustrates this system.

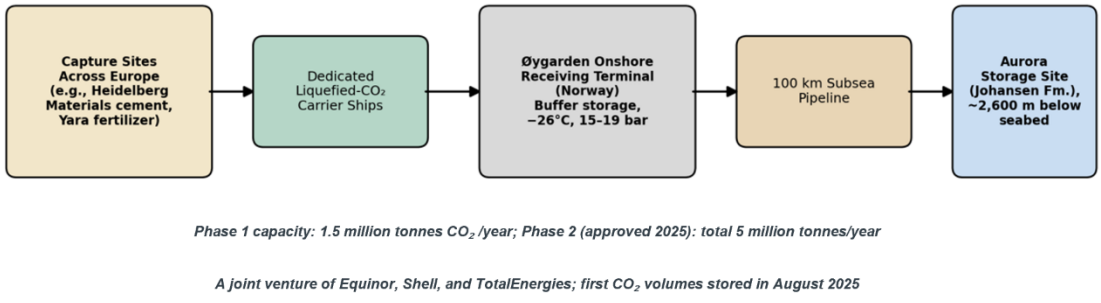

Figure 1.2. The Northern Lights CO_2 transport and storage system (Norway).

Diagram adapted from published project descriptions (Equinor, 2025; Northern Lights JV, 2025; TotalEnergies, 2025).

1.1.5 Why Multimodal CO_2 Transport Systems Are Necessary

Pipeline and marine transport, characterized in the two preceding sections, each carry advantages that are also, from a different angle, limitations: pipeline rewards sustained, high-volume, long-lived flow but is inflexible during the uncertain early stages of a project; marine transport is deployable incrementally but does not reach pipeline's cost efficiency at that same sustained scale. Neither is universally optimal, and this is not primarily a cost question decided case by case, but a structural one: real CCS deployment must operate within spatial, regulatory, and temporal constraints that vary across regions and over time, and these constraints determine which mode's advantages are actually available in a given setting, independent of which mode would otherwise be cheaper.

Industrial emissions are often unevenly distributed, requiring aggregation into clusters or corridors for transport to be efficient at all; Middleton and Bielicki (2009) show that network configuration and source aggregation are central to overall system cost and feasibility, not a secondary detail. Storage resources are frequently located offshore or in geographically constrained areas, requiring transport pathways that cross shorelines, navigable waterways, or environmentally sensitive regions, exactly the terrain where pipeline and marine transport face different regulatory regimes and jurisdictional frameworks (U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, 2022; U.S. Army Corps of Engineers, 2023). A real, current example illustrates the point directly: Japanese emitters facing limited domestic storage capacity have signed agreements to capture CO_2 and ship it roughly five thousand kilometers to offshore storage in Australia's Bonaparte Basin, a distance at which pipeline is not under serious consideration by any party involved (INPEX Corporation, 2024; Argus Media, 2024); Chapter 5 examines this case quantitatively using the framework developed in this thesis. A system that can only be described in terms of a single mode's economics, evaluated at a single point in time, will systematically miss the cases where the region's own geography, regulatory environment, or deployment stage favor the other mode, or a combination of both. This is the gap a multimodal, scenario-based evaluation framework is designed to close, and it is the starting point for the problem statement developed in Section 1.2.

1.2 Problem Statement

1.2.1 Fragmented Evaluation of CO_2 Transport Modes

Existing analyses of CO_2 transport systems frequently evaluate individual transport modes in isolation, rather than considering how they function within an integrated system. Pipeline transport has been extensively studied, particularly in the context of enhanced oil recovery and large-scale CCS networks, with detailed cost models and design frameworks available in the literature (IEAGHG, 2013; Knoope et al., 2013). Similarly, marine transport has been examined in studies assessing liquefied CO_2 shipping and its role in connecting dispersed sources to storage sites (Aspelund et al., 2006; IEAGHG, 2017).

However, these bodies of work are often developed independently, with limited attention to how pipeline and marine transport interact within a unified infrastructure system. As a result, comparisons between transport modes are frequently based on generalized cost curves or simplified assumptions that do not capture the interdependencies between modes. Middleton and Bielicki (2009) emphasize that CCS systems function as networks rather than isolated links, yet many transport studies continue to adopt a single-mode perspective. This disconnect limits the ability to evaluate tradeoffs, such as when marine aggregation reduces pipeline length or when pipeline trunklines improve system efficiency after initial deployment. Without integrated analysis, transport planning risks favoring suboptimal configurations that do not reflect real system behavior.

1.2.2 Limited Integration of Spatial and Infrastructure Constraints

A second limitation in existing work is the insufficient integration of spatial and infrastructure constraints into transport analysis. While many studies incorporate distance as a primary driver of transport cost, fewer explicitly account for the geographic and physical factors that influence route feasibility. These include shoreline conditions, land-use constraints, existing infrastructure corridors, and environmental sensitivities, all of which can significantly affect both the cost and feasibility of transport pathways.

In coastal regions such as the U.S. Gulf Coast, these constraints are particularly important. Shoreline crossings may involve unstable sediments, protected wetlands, or densely developed industrial zones, each of which introduces distinct engineering and permitting challenges. As noted in prior CCS infrastructure studies, route selection and local conditions can have a greater impact on project feasibility than nominal transport distance alone (Global CCS Institute, 2022). In addition, access to existing rights-

of-way or industrial corridors can reduce both cost and permitting complexity, while their absence can introduce substantial delays. Despite this, many transport models treat space in a simplified or abstract manner, limiting their ability to support location-specific decision-making.

1.2.3 Regulatory and Permitting Complexity Across Transport Modes

Transport mode selection is also influenced by regulatory and permitting frameworks, which vary significantly between pipelines and marine systems. Pipeline projects are typically governed by agencies responsible for pipeline safety, environmental review, and land use, requiring coordination across federal, state, and local jurisdictions (U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, 2022). In contrast, marine transport involves additional regulatory layers related to navigation, port operations, and maritime safety, including oversight by agencies such as the U.S. Coast Guard and port authorities (U.S. Army Corps of Engineers, 2023).

These differences create distinct permitting pathways for each transport mode, with implications for project timelines, risk, and feasibility. In many cases, permitting challenges can outweigh purely technical or economic considerations, particularly in regions with complex jurisdictional overlaps such as the Gulf Coast. For example, shoreline crossings may trigger both environmental review and coastal zone management requirements, while port modifications may require coordination with multiple authorities. However, regulatory factors are often treated qualitatively or excluded from quantitative transport models, resulting in analyses that do not fully capture real-world constraints on infrastructure development.

1.2.4 Absence of Decision-Oriented Multimodal Frameworks

The fragmentation of transport mode analysis, the limited treatment of spatial constraints, and the incomplete integration of regulatory considerations point to a broader gap in existing research. There is a lack of decision-oriented frameworks that can evaluate multiple CO_2 transport pathways within a consistent analytical framework.

While some studies have explored network optimization or scenario-based transport modeling, these approaches often rely on abstract representations of infrastructure or do not explicitly incorporate the practical constraints associated with shoreline crossings, port infrastructure, and permitting processes. As a result, they provide limited guidance for stakeholders seeking to evaluate real-world transport options under region-specific conditions. In particular, existing models rarely allow users to compare pipeline,

marine, and hybrid configurations under consistent assumptions while explicitly accounting for feasibility constraints.

1.2.5 Problem Statement Summary

In summary, current approaches to CO_2 transport analysis do not adequately capture the complexity of real-world CCS deployment. Existing studies tend to evaluate transport modes in isolation, simplify or omit spatial and infrastructure constraints, and underrepresent the role of regulatory and permitting processes. These limitations hinder the development of transport strategies that are both technically feasible and practically implementable.

Addressing this gap requires the development of a framework to evaluate pipeline, marine, and hybrid transport configurations within a unified, regionally grounded context. Such a framework must account for the interaction between spatial constraints, infrastructure characteristics, regulatory pathways, and project duration. It must also support transparent comparison across scenarios, allowing stakeholders to understand not only which option is preferable, but why. The absence of this capability motivates the research presented in this thesis.

1.3 Research Objectives and Questions

1.3.1 Research Objectives

The overarching objective of this thesis is to develop a decision-support framework for evaluating CO_2 transport strategies that integrates pipeline, marine, and hybrid transport configurations within a unified analytical structure. This framework is designed to address the limitations identified in the existing literature by incorporating spatial constraints, infrastructure considerations, regulatory factors, and project duration into the evaluation of transport systems. The goal is not only to compare transport modes, but to enable context-specific assessment of how different configurations perform under realistic deployment conditions.

To address the fragmentation of transport mode evaluation identified in Section 1.2.1, the first objective is to develop a comparative framework that evaluates pipeline, marine, and hybrid CO_2 transport systems within a consistent modeling environment. This includes establishing common assumptions for cost modeling, system boundaries, and performance metrics, allowing for direct comparison across

transport modes. By structuring the analysis in this way, the framework moves beyond isolated assessments and enables evaluation of how different transport modes interact within integrated systems, including identifying conditions under which hybrid configurations offer advantages over single-mode approaches.

In response to the limited integration of spatial and infrastructure constraints discussed in Section 1.2.2, the second objective is to incorporate spatially explicit considerations into the design and evaluation of transport systems. This involves accounting for factors such as shoreline crossings, route segmentation, proximity to existing infrastructure, and the geographic distribution of sources and sinks. The framework uses coordinate-based distance calculation and a protected-area crossing determination to evaluate how these constraints influence route feasibility and cost, supplemented by a qualitative characterization of the regulatory pathways and permitting bodies governing each transport mode. By explicitly integrating spatial factors, the analysis aims to produce results grounded in real-world conditions rather than abstract distance-based assumptions.

To address the regulatory and permitting complexities outlined in Section 1.2.3, the third objective is to incorporate regulatory considerations into the evaluation of transport system feasibility. This includes identifying key permitting pathways for pipeline and marine transport and assessing how these pathways influence project timelines, risk, and implementation feasibility. While regulatory factors are often treated qualitatively, this research seeks to systematically account for their impact within the broader decision-making framework, ensuring that transport strategies are evaluated not only on technical and economic grounds but also on the likelihood of their successful implementation.

In response to the absence of decision-oriented multimodal frameworks identified in Section 1.2.4, the fourth objective is to develop and implement a decision-support tool that enables structured comparison of transport scenarios under varying conditions. This tool is designed to evaluate trade-offs between cost, flexibility, scalability, and feasibility across pipeline, marine, and hybrid configurations. It also supports sensitivity analysis to assess how changes in key parameters, such as transport distance, volume, and infrastructure availability, influence optimal transport strategies. By providing a transparent and adaptable analytical tool, this research aims to support both academic analysis and practical decision-making.

1.3.2 Research Questions

To guide the development and application of the framework, this thesis addresses the following research questions:

RQ1. Under what conditions are pipeline, marine, or hybrid CO_2 transport systems most cost-effective and feasible?

This question focuses on how cost and feasibility vary across different system configurations, with particular attention to how transport distance, volume, and infrastructure availability influence the relative performance of each mode.

RQ2. How do spatial constraints, including shoreline crossings and infrastructure availability, affect transport system design and cost?

This question examines how geographic and physical factors shape transport pathways, influencing route feasibility, system configuration, and overall project cost.

RQ3. How do regulatory and permitting considerations influence the feasibility and timing of CO_2 transport system deployment?

This question considers how differences in regulatory frameworks across transport modes affect project timelines, risk, and implementation.

RQ4. How can a decision-support framework be structured to enable consistent comparison of multimodal CO_2 transport strategies under varying conditions?

This question focuses on the design of the analytical framework itself, including how technical, spatial, economic, and regulatory factors can be integrated to support transparent and robust evaluation of transport options.

RQ5. How might transfer hubs connecting different transport modes be owned, operated, and permitted, and what precedents exist for this kind of shared infrastructure?

This question addresses a structural dimension of multimodal transport systems that is often assumed rather than examined: the institutional arrangements that would govern a facility at which CO_2 moves from one transport mode to another. This includes the energy and infrastructure costs associated

with different types of transfer hubs, as well as the ownership, operating, and permitting models under which such facilities might function, informed by existing precedent from both the CO_2 transport sector and adjacent industries that rely on shared terminal infrastructure.

1.4 Methodology Overview

This research adopts a structured, multi-step methodology to evaluate CO_2 transport strategies across pipeline, marine, and hybrid configurations. The approach integrates spatial analysis, cost modeling, and scenario-based evaluation within a unified decision-support framework. Each component is designed to address limitations in existing transport studies, particularly the lack of integration between transport modes, the limited treatment of spatial constraints, and the absence of decision-oriented multimodal evaluation tools.

1.4.1 System Definition and Boundary Conditions

The analysis begins by defining system boundaries and key assumptions that guide transport system design. The study focuses on CO_2 transport between coastal and near-coastal emission sources, potential aggregation points or hubs where relevant, and offshore geologic storage locations. This framing reflects realistic deployment conditions in regions such as the U.S. Gulf Coast, where emitters are spatially distributed and where, alongside substantial onshore storage capacity already targeted by existing projects, very large offshore geologic storage resources remain largely undeveloped and increasingly attractive as a longer-term complement. Onshore CO_2 transport and injection is already underway at commercial scale in the United States, most notably in enhanced oil recovery service; this thesis does not evaluate onshore-only pathways, and instead focuses specifically on the future options for extending transport to offshore storage, a segment of the value chain that is comparatively undeveloped and less well characterized in the existing literature.

Rather than centering the analysis on a single predefined transport corridor, the study evaluates transport pathways across representative scenarios that capture variation in distance, volume, and infrastructure context. System boundaries include transport infrastructure components such as onshore pipeline segments, marine vessels and barges, port facilities, intermediate storage, and loading and unloading systems. These components are treated consistently across scenarios to allow direct comparison between pipeline-only, marine-only, and hybrid configurations.

Key assumptions include steady-state transport conditions for comparative purposes, consistent treatment of CO_2 phase conditions across transport modes, and standardized parameterization of transport distance, flow rate, and infrastructure availability. Together, these assumptions enable controlled comparison while maintaining relevance to real-world deployment.

1.4.2 Spatial Analysis and Route Characterization

Spatial analysis is used to estimate transport distances between emission sources, coastal landfall points, and offshore storage sites, using coordinate-based, great-circle distance calculation.

Routes are segmented into onshore and offshore components, each receiving distinct cost treatment, since the offshore segment carries the shoreline transition and the subsequent marine reach where pipeline and marine modes diverge most sharply in cost behavior. A geographic information system analysis determines whether a given route crosses or lies adjacent to a federally protected or environmentally sensitive area, informing the regulatory risk contingency applied to that scenario's cost.

By incorporating these spatial elements explicitly, the methodology moves beyond simplified straight-line distance alone and provides a more realistic basis for evaluating transport system design.

1.4.3 Transport Mode Modeling

Transport modes are modeled both individually and in combination to support consistent comparison across pipeline, marine, and hybrid systems. Pipeline transport is evaluated as a function of route distance and annual volume, with capital cost per kilometer scaled according to the diameter-sizing relationship established in the pipeline engineering-economic literature, reflecting that larger-diameter pipelines achieve lower capital cost per tonne of capacity.

Marine transport, ship and barge, is represented as a function of annual volume and transport distance, with capital cost scaled according to a vessel-capacity cost relationship analogous to pipeline's diameter-based scaling, plus an operating cost component and, for ship and articulated tug-barge transport specifically, a Jones Act cost premium reflecting United States-flagged vessel construction and crewing requirements. CO_2 is assumed to be transported as a refrigerated liquid under moderate pressure conditions, consistent with current ship-based transport designs.

Hybrid configurations combine a feeder mode, a transfer hub, and a primary mode within a single transport pathway. For instance, truck or rail may connect an inland or distributed source to a coastal transfer hub, from which pipeline or marine transport continues to offshore storage. Alternatively, marine transport may aggregate CO_2 from multiple coastal sources before delivery to centralized injection sites. These configurations are evaluated under consistent assumptions so that differences in performance reflect system design rather than modeling inconsistencies.

1.4.4 Cost Modeling and Economic Evaluation

Cost modeling is used to estimate capital expenditures, operational expenditures, and overall transport costs for each configuration. The analysis incorporates cost relationships from established CCS literature, including pipeline cost scaling with distance and volume-dependent diameter, and marine transport cost scaling with distance and volume-dependent vessel capacity, with a Jones Act premium applied to ship and articulated tug-barge transport specifically to reflect United States-flagged construction and crewing requirements.

Costs are evaluated on a per-ton basis to enable comparison across transport modes, while also considering total system cost for each scenario. Capital costs are amortized over project duration using a levelized-cost approach, allowing long-term cost performance to be assessed under different deployment durations.

Sensitivity analysis is conducted to evaluate how variations in key parameters, including transport distance, CO_2 volume, and project duration, influence cost outcomes, while distinct vessel and barge size classes are compared directly as discrete transport mode options rather than swept as a continuous parameter. This allows for the identification of thresholds at which different transport modes become more or less economically competitive.

1.4.5 Scenario Analysis and Sensitivity Assessment

A scenario-based approach is used to evaluate transport system performance under varying conditions. Scenarios are designed to represent a range of plausible deployment conditions, including differences in transport distance, CO_2 volume, spatial configuration of sources and sinks, and infrastructure availability.

Each scenario is evaluated within the same analytical framework to ensure consistent comparison across transport modes. Sensitivity analysis is applied to key variables to assess how changes in assumptions affect system design and performance. This includes examining how variations in distance thresholds, volume scaling, and cost parameters influence the relative competitiveness of pipeline, marine, and hybrid configurations. This approach allows for systematic exploration of tradeoffs and provides insight into conditions under which multimodal systems offer advantages over single-mode strategies.

1.4.6 Decision-Support Framework Development

The final step involves developing a decision-support framework that integrates results from spatial analysis, transport modeling, and cost evaluation. The framework is implemented in a structured format that allows users to input key parameters, such as transport distance, CO_2 volume, and infrastructure constraints, and evaluate corresponding transport options.

The tool is designed to support transparent comparison across scenarios, enabling users to assess tradeoffs between cost, feasibility, and flexibility. It also facilitates identification of conditions under which hybrid transport systems provide advantages, particularly in environments characterized by spatial and regulatory complexity. By combining these analytical components, the methodology provides a practical basis for evaluating CO_2 transport strategies in real-world CCS deployment contexts.

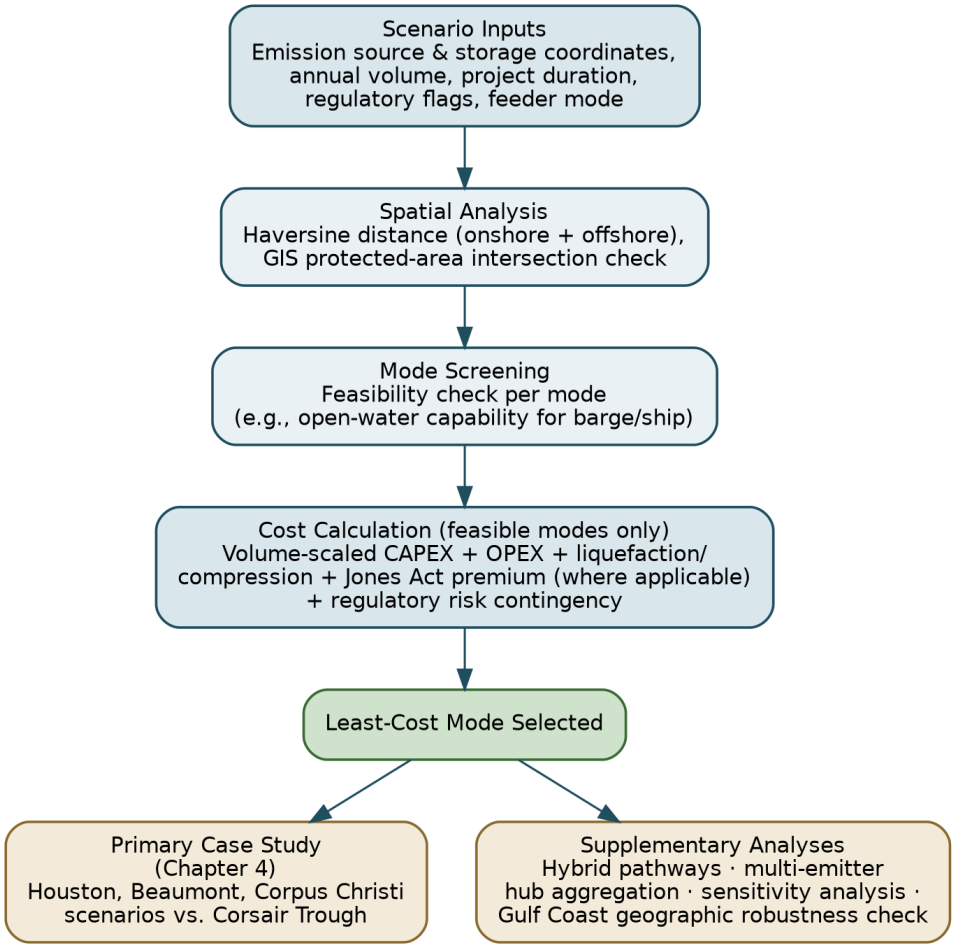

Figure 1.3. The decision-support framework's process flow.
Scenario inputs are used to calculate distance and screen for protected-area constraints, feasible transport modes are costed under a common cost structure, and the least-cost mode is identified, both for the primary Gulf Coast case study and for the supplementary analyses presented in Chapter 4.

1.5 Contributions

Building on the research objectives and methodology outlined above, this thesis makes several contributions to the analysis and design of CO_2 transport systems for carbon capture and storage deployment. These contributions address gaps in existing literature related to the fragmented evaluation of transport modes, the limited integration of spatial and regulatory constraints, and the absence of decision-oriented multimodal frameworks.

Contribution 1. Development of a multimodal CO_2 transport evaluation framework

This work develops a structured analytical framework that enables consistent evaluation of pipeline, marine, and hybrid CO_2 transport configurations within a unified system. Unlike conventional approaches that assess transport modes independently, the framework supports direct comparison across modes under consistent assumptions, including transport distance, volume, and infrastructure conditions. Bringing multiple transport pathways into a single analytical structure makes it possible to identify when hybrid configurations provide advantages over single-mode systems.

Contribution 2. Integration of spatial constraints into transport system design

Spatially explicit considerations are incorporated into the evaluation of CO_2 transport systems, including coordinate-based route distance, protected-area crossing risk determined through GIS analysis, and proximity to existing infrastructure, alongside a qualitative characterization of the regulatory pathways and permitting bodies governing each transport mode. Accounting for these geographic and physical constraints moves the analysis beyond simplified distance-based models and better reflects the challenges associated with real-world infrastructure development. This is particularly relevant in coastal regions, where spatial constraints play a central role in shaping feasible transport pathways.

Contribution 3. Incorporation of regulatory and permitting considerations into transport evaluation

Regulatory and permitting considerations are integrated into the assessment of transport system feasibility. By examining how permitting pathways differ across pipeline and marine transport modes, the analysis highlights the role of regulatory complexity in shaping infrastructure decisions. This extends the evaluation beyond purely technical and economic factors to include implementation-related constraints that are often underrepresented in transport modeling studies.

Contribution 4. Development of a scenario-based cost and sensitivity analysis approach

A scenario-based methodology is applied to evaluate how variations in key parameters, including transport distance, CO_2 volume, and infrastructure availability, influence transport system performance. Sensitivity analysis is used to identify critical thresholds and decision drivers that affect the relative competitiveness of pipeline, marine, and hybrid configurations. This provides insight into how transport strategies may evolve under different deployment conditions and uncertainty.

Contribution 5. Implementation of a decision-support tool for CO_2 transport strategy evaluation

The analytical framework is implemented as a decision-support tool that enables structured comparison of transport options under varying conditions. Users can input key parameters and evaluate tradeoffs between cost, feasibility, and flexibility across transport modes. By providing a transparent and adaptable platform for analysis, the tool supports both academic investigation and practical decision-making in CCS infrastructure planning.

Contribution 6. Characterization of transfer hub ownership, operation, and permitting models

This work examines a structural dimension of multimodal CO_2 transport that is frequently assumed rather than analyzed: how a facility at which CO_2 transfers between transport modes would be owned, operated, and permitted. Drawing on precedent from existing CO_2 pipeline hubs, international CO_2 shipping and storage projects, and shared marine terminal infrastructure in the petroleum sector, this analysis characterizes the range of institutional arrangements under which a Gulf Coast transfer hub might realistically operate, alongside the energy and infrastructure costs associated with different hub configurations. This contributes a governance-oriented perspective that complements the technical and economic modeling of transfer hubs elsewhere in this thesis.

1.6 Relevance and Beneficiaries

The findings and framework developed in this thesis are relevant to multiple stakeholder groups involved in the planning, analysis, and implementation of carbon capture and storage systems. By integrating technical, spatial, economic, and regulatory considerations into a unified approach, this research provides value to both academic and applied contexts.

1.6.1 Academic and Research Community

For the academic and research community, this thesis contributes to ongoing work on CCS infrastructure modeling by addressing the limitations of single-mode transport analysis. Existing studies often evaluate pipeline or marine transport independently, with limited integration of spatial and regulatory constraints. By developing a framework that evaluates multimodal transport configurations

within a consistent analytical structure, this research extends current approaches to CO_2 transport modeling.

In addition, incorporating spatially explicit factors, including protected-area crossing risk and proximity to existing infrastructure, provides a more realistic representation of transport system design. This supports future research that seeks to bridge the gap between abstract optimization models and geographically grounded infrastructure analysis. The scenario-based and sensitivity analysis components further contribute to methodological approaches for evaluating CCS systems under uncertainty.

1.6.2 Industry and Project Developers

For industry stakeholders and project developers, this research provides a practical framework for evaluating CO_2 transport strategies under real-world constraints. Transport mode selection is a critical component of CCS project design, with significant implications for cost, feasibility, and project timelines. By enabling structured comparison of pipeline, marine, and hybrid transport options, the framework developed in this thesis supports more informed decision-making during early-stage project planning.

The integration of spatial constraints and infrastructure considerations allows developers to better understand how site-specific conditions influence transport feasibility. In particular, the evaluation of protected-area crossing risk and proximity to existing infrastructure provides insight into challenges that may not be captured in simplified cost analyses. The decision-support tool developed in this research further enhances applicability by allowing users to explore how changes in key parameters affect transport strategy selection.

1.6.3 Policymakers and Regulatory Agencies

For policymakers and regulatory agencies, this research highlights the role of regulatory and permitting processes in shaping the development of CO_2 transport systems. Differences in regulatory frameworks across transport modes can influence project timelines, feasibility, and risk, yet these factors are often underrepresented in technical analyses.

By explicitly incorporating regulatory considerations into transport evaluation, this thesis provides insight into how policy and permitting structures interact with infrastructure design. This can support the development of regulatory approaches that facilitate CCS deployment while maintaining safety and

environmental standards. In regions such as the U.S. Gulf Coast, where multiple jurisdictions and regulatory frameworks intersect, this type of integrated analysis is particularly relevant for coordinated infrastructure planning.

1.7 Thesis Structure

This thesis is organized into five chapters, each addressing a specific component of the research.

Chapter 1 introduces the research context, including the role of CO_2 transport in CCS systems, the limitations of existing transport analyses, and the need for multimodal evaluation frameworks. It defines the problem addressed in this study, outlines the research objectives and questions, and provides an overview of the methodology and contributions.

Chapter 2 presents a review of relevant literature on CO_2 transport systems, including pipeline and marine transport technologies, cost modeling approaches, and existing frameworks for CCS infrastructure analysis. The chapter also examines prior work on spatial modeling and regulatory considerations, highlighting gaps that motivate this research.

Chapter 3 describes the methodology in detail, including system definition, spatial analysis, transport modeling, cost estimation, and scenario development. It outlines the structure of the decision-support framework and the assumptions used in the analysis.

Chapter 4 presents the results of the analysis, including comparative evaluation of transport scenarios, sensitivity analysis outcomes, and identification of key decision drivers. The performance of pipeline, marine, and hybrid transport configurations is assessed under varying conditions.

Chapter 5 discusses the implications of the findings, including insights for transport system design, study limitations, and recommendations for future research, and summarizes the thesis's key contributions and their relevance to CCS deployment. The chapter concludes by revisiting each research question in turn against the results presented in Chapter 4, and closing with a synthesis of the thesis's central argument.

CHAPTER 2: LITERATURE REVIEW

2.1 Overview of CO_2 Transport in CCS Systems

2.1.1 State of the Science: Transport System Design and Optimization

Rather than restate the case for transport's importance, already established in Chapter 1, this section summarizes what the existing literature has actually modeled and found, as a foundation for the more detailed, mode-specific reviews in Sections 2.2 through 2.6.

The most influential body of work on CO_2 transport system design is built around SimCCS, an optimization model introduced by Middleton and Bielicki (2009) and since extended through multiple versions (Middleton et al., 2012; Middleton et al., 2020). SimCCS jointly minimizes the annualized cost of capture, transport, and storage, selecting simultaneously where to capture CO_2, how much to store at each site, and where to build pipeline connections of what capacity, rather than treating transport as a downstream problem to be solved after capture and storage sites are already fixed. Two specific findings from this line of work directly inform the framework developed in this thesis. First, SimCCS demonstrates that aggregating CO_2 flows from multiple sources into shared trunk pipelines produces real economies of scale, a finding this thesis tests directly in its own multi-emitter hub analysis (Section 4.8). Second, SimCCS's routing algorithm treats pipeline construction cost as a function of the underlying terrain, explicitly penalizing routes through cities, environmentally sensitive areas, and water crossings, an approach this thesis's regulatory risk contingency (Section 3.7) addresses through a coarser, scenario-level risk rating rather than SimCCS's fine-grained cost-surface method, a simplification appropriate to this thesis's broader scenario comparison but a genuine loss of resolution relative to SimCCS's approach.

Onyebuchi et al. (2018) take a complementary, mode-comparison perspective rather than SimCCS's network-optimization perspective, systematically reviewing pipeline, ship, rail, and truck CO_2 transport across the literature and concluding that pipeline and ship transport dominate the published techno-economic literature by a wide margin, while rail and truck are almost exclusively discussed as feeder options connecting smaller or more dispersed sources to a primary pipeline or marine corridor, never as viable long-haul modes in their own right. This finding directly supports this thesis's own treatment of truck and rail as feeder-only modes, discussed in Section 2.4.6, rather than an assumption made without literature grounding.

Roussanaly et al. (2021), discussed further for its specific cost findings in Section 2.5.2, provides one of the most detailed published cost breakdowns for both pipeline and ship CO_2 transport across a range of distances and volumes, and is the single most heavily used source for cost calibration in this thesis, cited throughout Chapters 3 and 4. More recent work by Burger et al. (2026) extends this argument to deployment timing specifically, finding that multimodal transport options can shorten the time between an emitter's readiness to capture CO_2 and its ability to actually deliver that CO_2 to storage, compared to waiting for dedicated pipeline infrastructure to be built, a timing consideration distinct from the steady-state cost comparisons this thesis's own framework evaluates. Zhang et al. (2024) develop an optimization model specifically for multi-modal CO_2 transport network design, reinforcing from a different modeling tradition than SimCCS that multi-modal network structure, not mode choice in isolation, is the appropriate unit of analysis for CO_2 transport system design, the same premise underlying the framework developed in this thesis.

2.1.2 Scope and Structure of This Chapter

Building on this foundation, the remainder of this chapter reviews the literature mode by mode, in each case moving from general characteristics to the specific data and findings this thesis draws on directly. Section 2.2 reviews pipeline transport; Section 2.3 reviews marine transport; Section 2.4 reviews multimodal and hybrid systems; Section 2.5 reviews techno-economic cost data specifically; Section 2.6 reviews regulatory and permitting considerations; Section 2.7 situates this literature within the Gulf Coast context; and Section 2.8 identifies the specific gaps in this literature that this thesis's framework is designed to close.

2.2 Pipeline CO_2 Transport

2.2.1 Role of Pipelines in CCS Systems

Pipeline transport represents the foundational backbone of large-scale CO_2 transport systems, particularly in regions where high, sustained volumes of CO_2 must be transported between relatively fixed source and storage locations (Intergovernmental Panel on Climate Change [IPCC], 2005; Onyebuchi et al., 2018). Within CCS networks, pipelines enable continuous, high-capacity flow, making them especially well-suited for mature systems where capture rates are stable, and infrastructure utilization can be maximized (IEAGHG, 2013; Global CCS Institute, 2021).

Pipelines also impose a structural rigidity that distinguishes them from other transport modes. Once constructed, pipeline routes and capacities are largely fixed, requiring careful upfront planning to align with long-term deployment scenarios (Middleton & Bielicki, 2009). This characteristic makes pipelines highly efficient under stable demand but structurally less adaptable in early-stage or uncertain deployment environments, where volumes, routing needs, and storage availability may evolve over time (Roussanaly et al., 2021).

The role of pipelines is therefore closely tied to system maturity and scale. In early deployment phases, where CO_2 volumes are limited or geographically dispersed, pipeline investments may be underutilized or economically prohibitive (IEAGHG, 2017; Global CCS Institute, 2021). However, as systems scale and emission sources become aggregated, pipelines provide a cost-efficient and operationally reliable means of transporting large volumes over long distances, reinforcing their central role in established CCS infrastructure (Onyebuchi et al., 2018).

Critically, pipelines also serve as an integrating infrastructure within networked systems, enabling the aggregation of CO_2 from multiple emitters into shared transport corridors. This hub-and-spoke configuration supports economies of scale and facilitates coordinated system expansion, but introduces non-trivial coordination, regulatory, and capital requirements that must be resolved at the system level (Middleton & Bielicki, 2009; Roussanaly et al., 2021).

2.2.2 Technical and Operational Characteristics

CO_2 is typically transported in pipelines under dense-phase (supercritical or near-supercritical) conditions, which allow for higher transport efficiency by increasing fluid density and reducing volumetric flow requirements (Intergovernmental Panel on Climate Change [IPCC], 2005; Onyebuchi et al., 2018). These thermodynamic conditions are not merely operational preferences, but design-enabling constraints, as maintaining them directly affects pressure management, compressor requirements, and overall system efficiency (IEAGHG, 2013). Deviations can lead to phase changes that introduce pressure drops, flow instability, and increased recompression requirements, all of which impose additional energy and cost penalties (Intergovernmental Panel on Climate Change [IPCC], 2005).

Table 2.1 illustrates the direct relationship between pipeline diameter and annual carrying capacity that follows from this constraint, derived using the same continuity-based diameter-sizing approach

applied throughout this thesis's own cost model (Section 3.4), following McCoy and Rubin (2008): holding transport velocity and CO_2 density constant, required diameter scales with the square root of annual volume, so capacity scales with the square of internal diameter. This relationship is what actually distinguishes a feeder pipeline from a primary, trunk pipeline in this framework: the two are not different technologies, but the same pipe sized to different volumes. A feeder pipeline connects a single emission source, typically carrying a comparatively small, single-facility volume, and is accordingly sized to a smaller diameter; a primary or trunk pipeline carries the larger, often aggregated volume of multiple combined sources, and is sized to a correspondingly larger diameter. A pipeline built to the minimum practical diameter this thesis's own framework considers (NPS 4) carries under 350,000 tonnes per year, consistent with a single, modest feeder connection. In contrast, a pipeline four sizes larger (NPS 16) carries roughly ten times that volume, the scale at which aggregating multiple smaller sources onto one larger-diameter line becomes worthwhile. This is the same economies-of-scale relationship this chapter and Chapter 4 both discuss, expressed here directly in terms of the physical pipe itself.

Nominal Pipe Size (NPS)	**Internal Diameter (in)**	**Approximate Capacity (t/yr)**
4	4.03	339,000
6	6.07	770,000
8	7.98	1,334,000
10	10.02	2,102,000
12	11.94	2,984,000
16	15.00	4,710,000
20	18.81	7,409,000
24	22.62	10,716,000

Table 2.1. Pipeline diameter and approximate carrying capacity.
Derived from the diameter-sizing relationship in Section 3.4 (McCoy & Rubin, 2008).

These operating conditions introduce non-trivial engineering constraints on pipeline systems, including material selection, pressure containment, and fracture propagation control (Onyebuchi et al., 2018; IEAGHG, 2013). CO_2 streams may contain impurities such as water, hydrogen sulfide, or other gases, which can significantly affect corrosion behavior and pipeline integrity (Intergovernmental Panel

on Climate Change [IPCC], 2005; IEAGHG, 2016). As a result, CO_2 conditioning becomes a critical upstream requirement, with direct implications for both safety and lifecycle cost (IEAGHG, 2016).

Operationally, pipeline systems are characterized by continuous flow and high utilization requirements. Unlike batch-based transport modes, pipelines rely on steady throughput to maintain efficiency, making them sensitive to fluctuations in capture rates or system disruptions (Middleton & Bielicki, 2009; Roussanaly et al., 2021). This creates a strong interdependence between capture facilities, transport infrastructure, and storage operations, reinforcing the need for tight system integration and coordinated operation.

The technical characteristics of pipelines, therefore, translate directly into system-level constraints, in which reliability and efficiency are achieved through stability and consistency rather than flexibility. This distinction is critical in evaluating pipeline suitability within evolving CCS systems.

2.2.3 Cost Structure and Scaling Behavior

One of the defining features of pipeline transport is its economies of scale, which arise from the relationship between pipeline diameter, flow rate, and cost (Onyebuchi et al., 2018; Roussanaly et al., 2021). As pipeline capacity increases, the cost per unit of CO_2 transported generally decreases, making pipelines particularly attractive for high-volume applications (IEAGHG, 2013).

However, these economies of scale are accompanied by substantial upfront capital investment, including costs associated with materials, construction, right-of-way acquisition, and regulatory compliance (Global CCS Institute, 2021; IEAGHG, 2013). This results in a heavily front-loaded cost structure, requiring long-term, high utilization to achieve economic viability.

This leads to threshold-dependent deployment logic, in which pipelines become economically viable only beyond specific volume and distance thresholds (Roussanaly et al., 2021; Onyebuchi et al., 2018). Below these thresholds, alternative transport modes may offer greater flexibility and lower initial capital exposure, even if their long-term unit costs are higher. This makes pipeline deployment inherently sensitive to uncertainty in demand, scaling trajectories, and the timing of system expansion. This threshold-dependent behavior has been demonstrated empirically in techno-economic modeling of pipeline-based CO_2 transport networks in eastern Australia, where per-tonne transport and injection costs across a range of source-sink pairings varied by more than two orders of magnitude, from approximately

A$10 per tonne for a short, high-volume connection to over A$1,500 per tonne for a long, low-volume connection, driven primarily by distance, flow rate, and required well count (CO2Tech, 2009). These figures reflect Australian-dollar values and regional cost conditions that do not transfer directly to the Gulf Coast, but the underlying relationship- that per-tonne cost is highly sensitive to the combination of distance and throughput rather than either factor alone- is consistent with the threshold-dependent logic described above.

Pipeline cost behavior is also strongly influenced by route-specific constraints, including terrain, population density, environmental sensitivity, and land access (IEAGHG, 2013; Global CCS Institute, 2021). For example, urban corridors or environmentally protected areas can significantly increase construction costs and permit complexity, thereby altering the relative competitiveness of pipeline transport.

These cost dynamics position pipelines as the economically dominant solution in large-scale, centralized systems, while limiting their effectiveness in distributed or phased deployment scenarios.

2.2.4 Infrastructure Constraints and Permitting Considerations

Pipeline development is subject to extensive and often complex regulatory and permitting requirements, which can significantly influence both project timelines and feasibility (IEAGHG, 2013; Global CCS Institute, 2021). These requirements typically involve multiple layers of oversight, including environmental review, land-use approvals, safety regulations, and, in some cases, multi-jurisdictional coordination.

A major constraint in pipeline deployment is the challenge of right-of-way acquisition, particularly in regions with fragmented land ownership or competing land uses (Global CCS Institute, 2021). Securing continuous corridors for pipeline construction can be both time-intensive and costly, introducing uncertainty into project development and delaying system deployment.

Additional complexity arises in shoreline crossings and offshore transitions, where pipelines must interface with marine environments. These crossings often require specialized engineering design, environmental assessment, and regulatory approval, resulting in disproportionately high costs and extended permitting timelines relative to onshore segments (IEAGHG, 2017). In coastal regions such as the Gulf Coast, these constraints can be decisive factors in selecting transport modes. Compiled cost data

from multiple industry and literature sources places the offshore cost premium for new pipeline construction at roughly 1.4 to 14 times the equivalent onshore cost per inch-mile, with an average across compiled sources of approximately 3.6 times (Sachde et al., 2020). The pressure class selected for a new pipeline segment can itself determine how far offshore that segment can reach before an additional booster station is required: for a representative Gulf of Mexico case, a Class 600 pipeline, the rating typical of existing natural gas pipelines, could reach only about 8 miles from shore before pressure dropped below the level needed for injection, whereas a Class 900 pipeline, more typical of new CO_2 pipeline construction, could reach approximately 72 miles under the same delivery-pressure requirement (Sachde et al., 2020). This illustrates that offshore reach is a function not only of distance and cost, but also of the pressure class selected for the pipeline itself.

Permitting and regulatory constraints also introduce non-technical barriers that directly shape the feasibility, cost, and deployment timelines of infrastructure (Global CCS Institute, 2021). In some cases, these constraints may outweigh purely technical or economic considerations, underscoring the need to incorporate regulatory feasibility into transport system design.

2.2.5 Advantages and Limitations

Pipeline transport offers efficiency, reliability, and scalability that make it the preferred mode for large-scale CO_2 transport under stable operating conditions (Intergovernmental Panel on Climate Change [IPCC], 2005; Onyebuchi et al., 2018), but this comes with structural rigidity: pipelines require long-term planning, coordinated development, and sustained throughput to justify their capital cost (Middleton & Bielicki, 2009; Roussanaly et al., 2021), making them a limiting choice in early-stage deployment where capture volumes and storage availability remain uncertain (IEAGHG, 2017). Within a multimodal system, pipelines are best understood as the core infrastructure other modes connect to, rather than a universally optimal solution, complementing the flexibility of shipping and barging in ways this thesis's decision-support framework is designed to evaluate.

2.3 Marine CO_2 Transport

2.3.1 Fundamentals of CO_2 Shipping

Marine transport of carbon dioxide represents a fundamentally different paradigm from pipeline-based systems, shifting from continuous flow transport to a discrete, batch-based logistics framework

(Intergovernmental Panel on Climate Change [IPCC], 2005; IEAGHG, 2017). In this configuration, CO_2 is conditioned, transported in liquid form via vessels, and delivered intermittently rather than continuously, introducing non-trivial operational and design implications across the transport chain (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022; DNV Maritime Advisory, 2026). These distinctions are particularly important when evaluating the role of marine transport, by ship or by barge, within multimodal CO_2 transport systems.

At its core, a CO_2 shipping system consists of three interdependent stages: (i) conditioning and liquefaction of the captured CO_2 stream, (ii) intermediate storage and handling at export and import terminals, and (iii) marine transport using specialized carriers (IEAGHG, 2017; Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022). This multi-stage structure distinguishes shipping from pipelines, where compression and transport occur within a single integrated system. As a result, shipping systems are inherently more modular, but this modularity introduces additional coordination requirements across infrastructure nodes, which must be accounted for in system-level design and cost evaluation (Roussanaly et al., 2021).

CO_2 is typically transported in liquid form under low-temperature and moderate-pressure conditions, often in the range of approximately −50°C to −30°C and 6–15 bar (Intergovernmental Panel on Climate Change [IPCC], 2005; Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022). These conditions directly influence storage requirements, vessel design constraints, and energy consumption associated with liquefaction, making them a critical determinant of overall transport system cost (IEAGHG, 2017). Maintaining these thermodynamic conditions throughout the transport chain is therefore essential, as deviations can impose additional energy penalties, storage inefficiencies, and safety risks that propagate through system design and operational performance (Intergovernmental Panel on Climate Change [IPCC], 2005).

A defining characteristic of marine CO_2 transport is its decoupling of capture and storage operations, which contrasts with the continuous throughput requirements of pipeline systems (Roussanaly et al., 2021; IEAGHG, 2017). This decoupling enables the use of intermediate storage buffers, allowing CO_2 to be accumulated and transported in batches based on vessel availability and scheduling constraints. While this provides a strategic advantage in terms of flexibility and scalability, it also introduces additional complexities related to storage sizing, turnaround time, and fleet logistics, all of which directly influence

system cost and reliability (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022).

CO_2 shipping is particularly well-suited to scenarios involving geographic discontinuities, such as offshore storage sites or regions separated by natural or regulatory barriers where pipeline construction is technically challenging or economically prohibitive (IEAGHG, 2017; Global CCS Institute, 2021). In such contexts, shipping provides a means of bridging spatial gaps without requiring continuous infrastructure, thereby expanding the feasible design space for CCS transport systems.

However, the batch-based nature of shipping introduces complexities that are largely absent in pipeline systems. These include the need for fleet sizing and scheduling optimization, management of loading and unloading cycles, and coordination between multiple emitters and storage sites (Roussanaly et al., 2021; Noh & Kang, 2025). System performance is influenced by factors such as voyage distance, vessel capacity, port infrastructure constraints, and operational variability, all of which serve as key decision variables in transport mode selection and system optimization.

In contrast to pipelines, which achieve economies of scale primarily through increased diameter and sustained high throughput, shipping systems scale through fleet expansion and vessel size optimization (IEAGHG, 2017; Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022). This distinction has important implications for infrastructure planning and investment timing, particularly in early-stage CCS deployment where transport volumes are uncertain or gradually increasing. In such contexts, shipping offers a strategic advantage by enabling incremental scaling without requiring large upfront capital commitments.

Overall, marine CO_2 transport should not be viewed as a direct substitute for pipeline infrastructure, but rather as a complementary mode that expands the feasible design space of CCS transport systems (Roussanaly et al., 2021). Its role is especially relevant in scenarios characterized by offshore storage, distributed emission sources, and evolving infrastructure networks, where flexibility, modularity, and adaptability outweigh the efficiency advantages of pipeline-based systems. These characteristics form a critical foundation for evaluating multimodal transport configurations and inform the decision-support framework developed in this study. Barge transport shares this same batch-based, decoupled logistics structure, but occupies a distinct niche within it: rather than bridging long ocean distances, barges primarily serve shorter, protected-water routes, either as a feeder connection to a coastal hub or, in the

articulated tug-barge configuration, as a primary mode capable of a limited open-water crossing, discussed further in Section 2.3.6. This positions barge and ship as complementary rather than substitute marine modes within a multimodal system, serving different segments of a transport pathway according to route length and open-water exposure rather than competing directly for the same voyage.

2.3.2 Liquefaction and Storage Requirements

A defining feature of marine CO_2 transport systems is the requirement for conditioning, liquefaction, and intermediate storage, which together constitute a significant portion of both system complexity and cost (IEAGHG, 2017; Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022). Unlike pipeline transport, where compression enables continuous flow, shipping systems rely on phase change to achieve sufficient density for efficient transport, introducing additional thermodynamic and infrastructure considerations that directly influence system design and performance (Intergovernmental Panel on Climate Change [IPCC], 2005).

Liquefaction is necessary to reduce the volumetric footprint of CO_2 for transport, typically achieved by cooling and pressurizing the gas to low-temperature, moderate-pressure conditions (IEAGHG, 2017). This process is energy-intensive, and the compression work it requires rises sharply with seawater temperature, since warmer cooling water reduces heat-exchanger efficiency and increases the vapor load the compressors must handle (Noh & Kang, 2025). Even so, boil-off gas reliquefaction specifically has been found to account for a comparatively modest share of total ship transport cost, on the order of three to six percent across a range of ship sizes and distances, though it corresponds to a larger fraction, on the order of fifteen to seventeen percent, of ship capital expenditure alone (Noh & Kang, 2025). The energy requirements for liquefaction are influenced by inlet CO_2 conditions, impurity composition, and desired transport specifications, making upstream capture and conditioning processes directly relevant to downstream transport efficiency.

The thermodynamic conditions selected for CO_2 liquefaction impose design constraints on storage systems at both export terminals and receiving facilities (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022). Cryogenic or semi-refrigerated storage tanks must be designed to maintain stable temperature and pressure conditions while minimizing boil-off and thermal losses (IEAGHG, 2016). These requirements introduce additional capital costs and operational considerations, including insulation performance, pressure management systems, and safety controls.

Intermediate storage plays a critical role in decoupling capture and transport, enabling CO_2 to be accumulated prior to loading and temporarily held upon arrival before injection (Roussanaly et al., 2021). However, the sizing of storage capacity introduces a key design trade-off. Undersized storage can lead to bottlenecks, limiting throughput and increasing operational inefficiencies, while oversized storage increases capital costs without proportional system benefits (Seo et al., 2017).

The integration of liquefaction and storage infrastructure also introduces temporal and operational coupling between different components of the CCS system. Variability in capture rates or delays in vessel arrival can propagate through the system, affecting storage levels, energy consumption, and overall system efficiency (IEAGHG, 2017).

Ship capital expenditure remains the dominant component of total maritime transport cost, with reliquefaction and terminal-side infrastructure contributing a smaller, though non-negligible, share that grows with transport distance and, notably, with seawater temperature (Noh & Kang, 2025). This shifts the economic focus from transport distance alone to a broader set of factors, including energy prices, storage design, and operational efficiency.

These considerations are central to transport mode selection within CCS systems. While shipping offers flexibility and modularity, the additional requirements for liquefaction and storage introduce cost and complexity that may offset these advantages under certain conditions. Barge transport faces the same conditioning and storage requirements in principle, but at the semi-refrigerated, higher-pressure end of the phase range described above, rather than the deep-cryogenic conditions typical of long-haul ship transport. Since barge routes are generally shorter, the case for accepting the heavier, pressure-rated tank design in exchange for a smaller liquefaction energy burden is correspondingly stronger, as discussed further in Section 2.3.6.

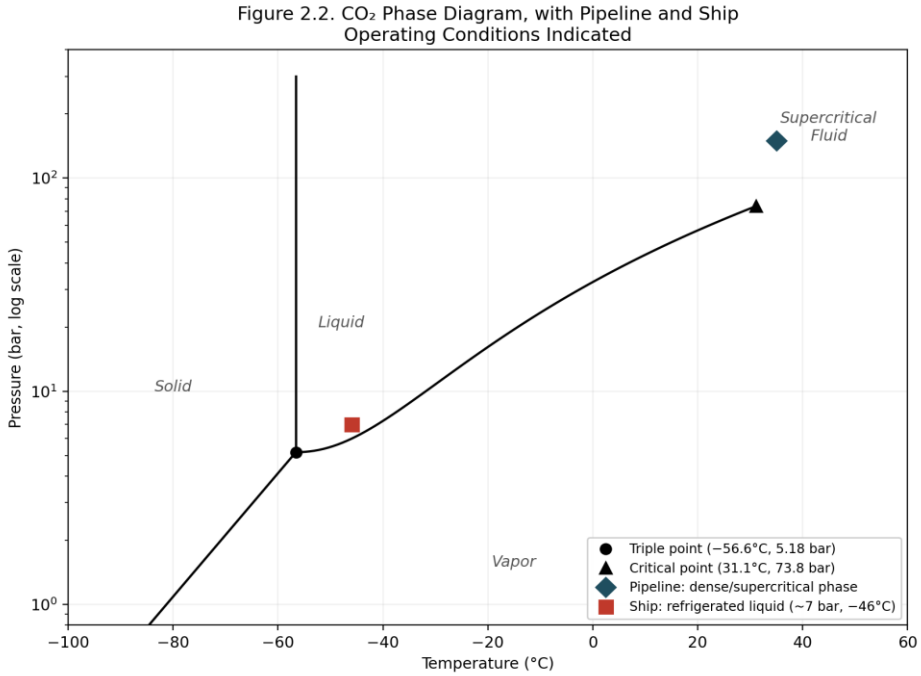

Figure 2.1. CO_2 phase diagram, with pipeline and ship operating conditions indicated.

Triple point and critical point are established physical constants; the ship operating condition shown follows the low-pressure shipping convention used to calibrate this framework's own ship cost parameters (Roussanaly, Deng, et al., 2021), one of at least two pressure regimes used in real projects, discussed further below.

The pressure and temperature at which CO_2 ships are operated is not a settled engineering question; Roussanaly, Deng, et al. (2021) frame it explicitly as a design choice with real cost consequences, comparing low-pressure (approximately 7 bar) against higher-pressure (approximately 15 bar) shipping, and this thesis's own ship cost parameters, discussed in Section 3.5, are calibrated against sources using the low-pressure convention. Real projects differ: Northern Lights, discussed in Section 1.1.4, instead operates its onshore buffer storage at approximately 15 to 19 bar. This framework does not evaluate the cost difference between these two pressure regimes directly, and the specific ship cost figures reported throughout this thesis should accordingly be read as representative of the low-pressure convention specifically, not of CO_2 shipping in general.

2.3.3 Vessel and Port Infrastructure Considerations

The effectiveness of marine CO_2 transport systems is strongly governed by the design and coordination of vessel and port infrastructure, which together define the operational capacity, scalability, and logistical feasibility of shipping-based transport (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022; DNV Maritime Advisory, 2026).

Fleet sizing represents a central design and optimization challenge in marine CO_2 transport systems (Roussanaly et al., 2021). Determining the appropriate fleet size requires balancing capital investment with operational considerations such as turnaround time, loading and unloading durations, and travel distance (Noh & Kang, 2025).

Port infrastructure imposes additional constraints that can significantly influence system design (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022). Export and import terminals must be equipped with liquefaction integration, storage facilities, and loading systems compatible with vessel specifications (DNV Maritime Advisory, 2026). Limitations related to port draft, berth availability, and handling capacity can restrict vessel size and influence scheduling strategies.

The interaction between vessel design and port infrastructure introduces system-level coupling that must be explicitly considered in transport planning (Roussanaly et al., 2021). Operational variability—such as weather, congestion, and maintenance—further necessitates buffer capacity and scheduling flexibility (IEAGHG, 2017). Barge infrastructure introduces a related but distinct constraint: rather than deep-water berths, barge routes depend on inland channel depth and lock capacity, and vessel sizing is governed primarily by draft rather than propulsion or port handling capacity, discussed further in Section 2.3.6.

2.3.4 Cost and Operational Considerations

The economic performance of marine CO_2 transport systems is governed by a multi-component cost structure that differs fundamentally from pipeline-based transport (IEAGHG, 2017; Noh & Kang, 2025). Shipping systems distribute costs across liquefaction, storage, vessel capital, and operations, resulting in a more complex relationship between cost, distance, and transport volume.

Reliquefaction and storage infrastructure add a real, if secondary, share to total system cost, one that is more pronounced relative to ship capital expenditure specifically than relative to total transport

cost, and that increases with both transport distance and seawater temperature (Noh & Kang, 2025). As a result, cost comparisons between shipping and pipelines must consider integrated system components rather than distance alone. Shipping systems also exhibit non-linear cost behavior driven by discrete vessel sizes and fleet requirements (Roussanaly et al., 2021). Changes in throughput may require step increases in fleet size, introducing discontinuities in cost scaling and complicating techno-economic analysis.

Shipping tends to be more economically favorable in scenarios with moderate distances, lower or variable volumes, and constrained pipeline routing conditions (IEAGHG, 2017; Global CCS Institute, 2021). Conversely, pipelines dominate in high-volume, long-term applications. Operationally, shipping requires coordination of scheduling, storage, and vessel logistics, making system performance sensitive to variability (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022). Buffer capacity and flexibility are therefore essential components of system design. Barge cost structure follows the same general components as ship, capital, operating, and liquefaction cost. However, its shorter typical route length and smaller vessel scale shift the relative weight of these components, and its cost-distance behavior is accordingly distinct from ship's, discussed further in Chapter 3. This crossover has been characterized qualitatively in industry analysis as a comparison of two cost curves against transport distance: pipeline cost rising steeply but from a lower base, and ship cost starting higher but rising more gradually, such that pipelines remain competitive over a shorter distance range and ships become competitive beyond it, with the crossover itself falling within an uncertain, case-dependent range rather than at a fixed distance (Blue Sky Maritime Coalition, 2024, citing METI, 2017). Industry practitioners consulted for this research similarly emphasized that no fixed distance or volume threshold reliably determines pipeline versus marine transport competitiveness, whether by barge or by ship; the outcome depends on pipeline length and diameter, regional construction cost, and permitting requirements specific to each case (E. Vera, personal communication, 2025), consistent with the threshold-dependent, rather than fixed-rule, framework developed in this thesis.

2.3.5 Advantages and Limitations

Marine CO_2 transport offers operational flexibility due to the decoupling of capture, transport, and storage processes (IEAGHG, 2017). This enables batch transport and incremental scaling, making it particularly valuable in early-stage CCS deployment. Shipping also provides a critical solution to

geographic and regulatory constraints, particularly for offshore storage or regions where pipelines are infeasible (Global CCS Institute, 2021).

However, these advantages are offset by increased system complexity, including liquefaction, storage, and coordination requirements (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022). Shipping systems also exhibit non-linear cost scaling, making optimization more challenging under uncertain conditions (Roussanaly et al., 2021). The trade-off between flexibility and efficiency is therefore central. Shipping offers adaptability and lower initial capital requirements but may involve higher operational complexity and cost.

Within a multimodal system, marine transport functions as a complementary component, enabling hybrid configurations that expand the feasible design space of CCS transport networks. These characteristics define the conditions under which marine transport is most appropriate and reinforce the need for system-level evaluation frameworks that support transport mode selection (Middleton & Bielicki, 2009). Barge transport presents its own version of this trade-off: lower capital cost and a mature, competitive domestic fleet, discussed in Section 2.6.3, against a shorter practical range and, in its conventional configuration, no capability for open-water crossing at all, restricting it to a feeder role except where the articulated tug-barge configuration is used.

2.3.6 Vessel Configurations and Phase Conditions

CO_2 marine transport is not a single, uniform mode; the phase and pressure conditions under which CO_2 is carried vary across vessel designs, with direct implications for cost and operational range. Deep-refrigerated, or cryogenic, vessels carry CO_2 at low pressure and low temperature, typically near 7 bar and negative fifty degrees Celsius, requiring a liquefaction process that removes substantial heat from the CO_2 before loading (Element Energy & UKCCSRC, 2020). This configuration is well suited to longer voyages, since the deeply refrigerated state requires comparatively less energy to maintain over an extended transit. However, the liquefaction step itself is capital- and energy-intensive. Semi-refrigerated, or pressurized, vessels instead carry CO_2 at a higher pressure, typically in the range of 15 to 20 bar, and a correspondingly higher temperature, trading a smaller liquefaction energy requirement for a heavier, more pressure-resistant tank design. This configuration is generally more appropriate for shorter voyages, where the reduced liquefaction burden outweighs the added structural cost of the pressure-rated tank.

This framework accordingly distinguishes three ship configurations: small and large cryogenic vessels, intended for longer-haul service, and a small, pressurized vessel, intended for shorter-haul service. The pressurized configuration is also treated differently with respect to United States maritime regulatory cost, discussed further in Section 3.5, since vessels of this type may be retrofitted from existing pressurized gas carriers already in domestic service, whereas a deep-cryogenic CO_2 carrier has no comparable existing vessel class to draw upon.

Northern Lights, discussed in Section 1.1.4, illustrates the semi-refrigerated approach at commercial scale: its Northern Pioneer vessel, the world's first purpose-built liquefied CO_2 carrier, transports CO_2 at a maximum of 19 bar and a minimum of −35°C, conditions between the two configurations described above and closer to the semi-refrigerated end of the range. No purpose-built vessel currently operates at the deep-cryogenic end of the spectrum described here; Figure 2.2 illustrates the two configurations using a real liquefied natural gas carrier, a vessel type sharing cryogenic CO_2's low-temperature handling requirements, as the closest available visual analog, alongside a photograph of the Northern Pioneer itself.

Figure 2.2a. A liquefied natural gas (LNG) carrier, shown here as a visual analog for the cryogenic handling requirements CO_2 transport shares with LNG shipping.
This is not a CO_2-specific vessel; no purpose-built deep-cryogenic CO_2 carrier is currently in commercial operation. Photo: Kawasaki Heavy Industries (n.d.).

Figure 2.2b. The Northern Pioneer, Northern Lights' purpose-built liquefied CO_2 carrier. The world's first commercial vessel of its kind, operating at conditions closer to the semi-refrigerated end of the range described above (maximum 19 bar, minimum −35°C). Photo: Baird Maritime (2025), courtesy of K Line.

Barge transport of CO_2 exhibits its own configuration distinction, analogous to the ship phase-condition distinction described above. Conventional tug-assisted and push-tow barges rely on a flexible or rigid coupling to the tug that is not designed to withstand sustained open-ocean sea states, restricting these vessels to protected waterways. Articulated tug-barges (ATBs) instead use a mechanical coupling in which the tug's bow fits into a notch cut into the stern of the barge, where pins or rams extend to lock the two vessels together; this connection is engineered to permit pitch, allowing the tug to rock independently of the barge in response to waves, while still preventing roll and yaw, the side-to-side and swinging motion a simple towline cannot control. This one-degree-of-freedom connection is what allows an ATB to extend barge service into coastal and open-water conditions that would otherwise require a self-propelled ship, and is why this framework treats the ATB, rather than conventional configurations, as a primary long-haul transport option. Barge sizing in either configuration is governed primarily by draft rather than propulsion, since CO_2's specific gravity of approximately 1.1 makes it heavy relative to many bulk liquid cargoes typically carried on these routes; industry experience with a representative oversized barge design of approximately 295 by 54 feet, operating within a typical inland

channel depth near nine feet, indicates a practical capacity of approximately 2,400 cubic meters of CO_2 per barge (E. Vera, personal communication, 2025). Regional context specific to the Gulf Coast, including tow configuration and towboat horsepower, is discussed further in Section 2.7.6.

Figure 2.2c. An articulated tug-barge (ATB).
The tug Ronnie Murph coupled to the 155,000-barrel barge Kirby 155-03, one of Kirby Corporation's fleet of Jones Act-compliant coastal tank barges. Photo: WorkBoat Staff (2018).

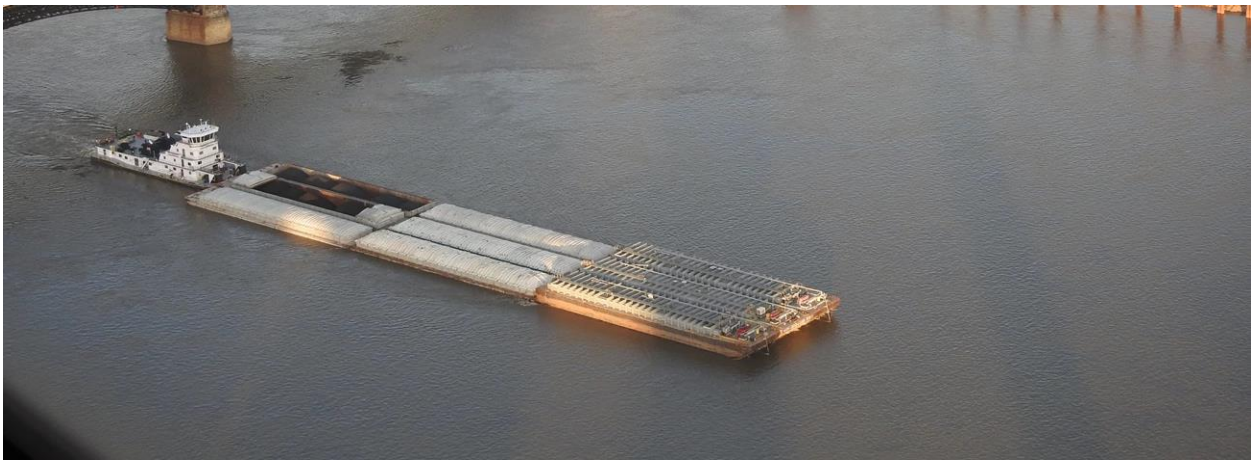

Figure 2.2d. A conventional towboat pushing barges on the Mississippi River.
Illustrating the simple towline connection used on protected inland waterways, without the engineered pitch joint of an ATB. Photo: National Park Service (n.d.).

2.4 Multimodal CO_2 Transport Systems

2.4.1 Rationale for Multimodal Transport

The development of large-scale CCS systems increasingly requires the integration of multiple transport modes rather than reliance on a single mode alone, since emission sources are often

geographically dispersed while suitable storage sites, particularly offshore formations, sit at distances not easily reached by any one mode (IEAGHG, 2017; Middleton & Bielicki, 2009; Reyes-Lua et al., 2021).

This is especially relevant in regions such as the Gulf Coast, where dense industrial clusters, inland waterways, and offshore storage opportunities create a highly interconnected but constrained infrastructure landscape (Gunawan et al., 2024). Multimodal transport is driven by deployment strategy as much as by geography: smaller, distributed sources may rely on flexible modes such as trucking or barging to aggregate CO_2 before transitioning to pipeline or shipping as volumes grow, allowing incremental infrastructure development while limiting upfront capital risk (Onyebuchi et al., 2018; Middleton et al., 2012).

2.4.2 System Architecture and Network Configurations

This system architecture, introduced conceptually in Figure 1.1a, applies directly here: distributed CO_2 sources connect through onshore feeder modes to a transfer hub, where CO_2 is aggregated, compressed, and prepared for a primary offshore transport mode to reach the storage site.

Multimodal CO_2 transport systems are best understood as integrated networks, rather than linear transport chains (Middleton & Bielicki, 2009; Roussanaly et al., 2021; ZEP & CCSA, 2022). These networks consist of multiple interconnected components, including capture facilities, pipelines, transfer terminals, intermediate storage sites, ports, and storage reservoirs.

A common configuration within such systems is the hub-and-spoke model, in which CO_2 from multiple emitters is aggregated at central hubs before being transported to storage sites (Middleton & Bielicki, 2009). Pipelines often serve as the primary aggregation mechanism, while shipping or barging enables long-distance or offshore transport (IEAGHG, 2017; Reyes-Lua et al., 2021). This configuration supports economies of scale while allowing for geographic flexibility.

In addition to hub-based systems, distributed network configurations may emerge in regions with highly dispersed sources or limited infrastructure connectivity (Onyebuchi et al., 2018; Pett-Ridge et al., 2023). In these systems, smaller-scale transport modes such as trucking or rail may play a role in connecting emitters to larger transport corridors (Myers et al., 2024). While less efficient at scale, these configurations can provide critical early-stage connectivity.

A defining feature of multimodal systems is the presence of transfer interfaces, where CO_2 transitions between transport modes (Roussanaly et al., 2021; Gunawan et al., 2024). These interfaces may include pipeline-to-ship terminals, barge loading facilities, or storage buffers that enable decoupling between transport segments. The design and operation of these interfaces introduce additional complexity, as they must accommodate differences in pressure, temperature, flow regimes, and scheduling.

These network architectures highlight that transport system performance is not determined solely by individual modes, but by the interactions between modes and infrastructure components, making system integration a central design challenge (Middleton & Bielicki, 2009; ZEP & CCSA, 2022).

2.4.3 Role of Intermediate Storage and Decoupling

A key enabling feature of multimodal CO_2 transport systems is the use of intermediate storage, which allows for the decoupling of different transport segments (Roussanaly et al., 2021; IEAGHG, 2017). Unlike pipelines, which operate under continuous flow conditions, multimodal systems often involve batch-based transport processes that require temporal alignment between capture, transport, and storage operations.

Intermediate storage provides buffer capacity, allowing CO_2 to be accumulated, held, and dispatched according to the availability of downstream transport or storage infrastructure (IEAGHG, 2017; ZEP & CCSA, 2022). This is particularly important in systems involving shipping or barging, where transport is inherently intermittent and subject to scheduling constraints.

The inclusion of storage buffers enhances system flexibility and resilience, enabling operations to continue even in the presence of disruptions or variability in one part of the system (Roussanaly et al., 2021). However, this flexibility comes at the cost of additional infrastructure, including storage tanks, compression systems, and handling facilities.

The sizing and placement of intermediate storage is itself a critical optimization problem, influencing system efficiency, cost, and operational reliability (Seo et al., 2017; Middleton et al., 2012). Insufficient storage capacity can lead to bottlenecks and downtime, while excessive capacity increases capital expenditure without proportional benefit.

Thus, intermediate storage plays a central role in enabling multimodal systems, but introduces additional trade-offs between flexibility, cost, and complexity that must be carefully evaluated.

2.4.4 Operational Complexity and Coordination Requirements

While multimodal systems offer increased flexibility, they also introduce significant operational complexity (Roussanaly et al., 2021; IEAGHG, 2017; ZEP & CCSA, 2022). Unlike single-mode systems, which can often be optimized around steady-state conditions, multimodal systems require coordination across multiple transport segments, each with distinct operational characteristics. For example, pipelines operate continuously, while shipping and barging involve discrete transport cycles with defined loading and unloading schedules. Aligning these different modes requires careful coordination to avoid delays, inefficiencies, or system imbalances (IEAGHG, 2017).

This coordination challenge is further compounded by variability in external factors, such as weather conditions, port congestion, and infrastructure availability. These factors can introduce uncertainty into transport schedules, requiring systems to be designed with sufficient flexibility to accommodate disruptions.

This shifts the focus from purely engineering-based design toward logistics and operations management, where scheduling, routing, and system integration become critical determinants of performance (Middleton & Bielicki, 2009; Gunawan et al., 2024). The increased complexity of multimodal systems, therefore, necessitates more advanced planning and optimization approaches, particularly as systems scale and involve multiple stakeholders (Roussanaly et al., 2021; Middleton et al., 2012).

2.4.5 Implications for Transport Mode Selection and System Design

The emergence of multimodal CO_2 transport systems shifts mode selection from a single optimal choice to a system-level decision that weighs volume, distance, infrastructure, and regulatory considerations simultaneously (Middleton & Bielicki, 2009; Roussanaly et al., 2021). Pipelines tend to be preferred in high-volume, stable systems, while shipping or barging can offer advantages in flexible, early-stage, or geographically constrained scenarios (IEAGHG, 2017; Global CCS Institute, 2021), and the optimal configuration often combines modes, each fulfilling a specific role within the broader system.

2.4.6 Feeder Mode Specifications: Truck and Rail

Truck and rail transport function within multimodal CO_2 systems primarily as feeder modes, connecting distributed emission sources to an aggregation hub or primary transport corridor, rather than

serving as standalone long-haul alternatives to pipeline or marine transport (Gunawan et al., 2024). Both modes transport CO_2 in pressurized tank equipment rather than in refrigerated, liquefied form: truck transport uses pressurized tank trailers, and rail transport uses pressurized tank cars of the DOT-105 and DOT-112 class, the same general equipment class used for other pressurized industrial gases such as ammonia and propane.

A deep-cryogenic rail tank car class, comparable to the DOT-113 cars used for liquefied natural gas, does not exist as a viable commercial option for CO_2 at present. Equipment of this specialized type is not manufactured at meaningful scale given limited demand, a condition documented in the liquefied natural gas rail tank car market and understood to apply similarly to a CO_2-specific cryogenic rail car. This distinguishes rail's feeder role in this thesis from the deep-cryogenic configurations considered for ship transport in Section 2.3.6, and is addressed further in the framework's scope, described in Chapter 3.

Beyond equipment class, truck and rail also differ from barge transport in their safety and fuel-efficiency profiles at scale. In a national multi-year comparison of domestic freight modes, inland waterway barge transport showed a fatality rate of 0.0005 per 100 million vehicle-miles traveled, compared to 0.01 for rail and 1.62 for truck, and a fuel efficiency of 675 ton-miles per gallon, compared to 472 for rail and 151 for truck (Kruse et al., 2022). This comparison is drawn from general domestic freight, specifically grain and bulk commodity traffic, rather than CO_2 specifically. However, the underlying safety and efficiency advantage of water-based transport over truck and rail is consistent with this thesis's treatment of truck and rail as feeder modes for smaller, localized volumes rather than as long-haul alternatives to barge or pipeline transport.

Despite the growing recognition of multimodal transport in CCS systems, existing literature remains fragmented, with limited integration across transport modes and insufficient focus on system-level optimization (Roussanaly et al., 2021; Onyebuchi et al., 2018). Addressing this gap by developing a structured approach to multimodal transport evaluation is a central objective of this thesis.

2.4.7 CO_2 Transfer Safety Risk

Multimodal transport systems introduce a consideration distinct from cost or regulatory jurisdiction: operational safety risk at the points where CO_2 transitions between transport modes. CO_2 is frequently characterized as a simple asphyxiant. However, occupational safety and toxicology literature

indicates that it can act as both an asphyxiant and a toxicant at elevated concentrations, with symptoms that follow a fairly well-defined concentration gradient: headache, dizziness, and impaired judgment in the range of three to five percent by volume, loss of consciousness within minutes at seven to ten percent, and a substantial risk of death at ten percent or above (Permentier et al., 2017; European Industrial Gases Association, 2011; Occupational Safety and Health Administration, 1996). Because CO_2 is denser than air, releases tend to form ground-hugging clouds capable of accumulating in low-lying areas, trenches, and semi-enclosed spaces, a hazard directly relevant to truck and barge transfer points, which often include recessed manifolds, hose troughs, and partially sheltered work areas (Occupational Safety and Health Administration, 1996; Health & Safety Executive, 2024).

While public documentation of major CO_2 releases specifically during truck or barge transfer is limited, related incident records provide insight into credible hazards. A 2020 pipeline rupture near Satartia, Mississippi generated a dense, ground-hugging cloud that traveled along topographic lows, resulting in loss of consciousness among nearby residents, vehicle stall-outs, and a large-scale emergency response (Pipeline and Hazardous Materials Safety Administration, 2022; Ogle et al., 2025). Although this incident involved a transmission pipeline rather than a transfer operation, it demonstrates that CO_2 releases can produce community-scale impacts when terrain channels the resulting plume, a consideration directly relevant to Gulf Coast transfer terminals sited in low-lying coastal environments.

A related but mechanically distinct hazard arises from the physical behavior of CO_2 itself during pressure letdown. Because CO_2 forms solid dry ice when depressurized from a liquid or dense-phase state toward atmospheric pressure, any relief valve, vent line, or other pressure-reducing device handling CO_2 is susceptible to plugging by dry ice, hydrates, or, in streams carrying trace contaminants, reaction-product solids, a documented failure mode in gas-processing and refining service more broadly (Kerr & Myers, 2021). A plugged pressure relief valve cannot perform its safety function during an overpressure event, which makes this a design consideration wherever pressure is let down along a CO_2 transport pathway, including truck and barge transfer manifolds, rather than a hazard confined to the release of CO_2 itself. Established practice for mitigating this risk includes heat tracing of relief valve inlet piping, inert gas purging of stagnant lines, and selection of relief valve types suited to solids-prone service (Kerr & Myers, 2021).

Transfer operations introduce failure modes distinct from those present during steady-state transport, including hose or transfer-line failure, connection and coupling failures, valve maloperation, overfilling, and mechanical loading from vessel or vehicle movement during truck-to-barge transfers (European Industrial Gases Association, 2020; Wen et al., 2013). Modeling of dense-phase CO_2 releases, including work conducted under the COOLTRANS and CO_2PipeHaz research programs, indicates that ground-level concentrations can remain elevated over considerable distances under low-wind conditions, particularly where physical features such as berms, retaining walls, or vessels positioned below jetty height can trap or channel dense gas (Allason et al., 2012; Gant, 2012; Health & Safety Executive, 2013). At the same time, transfer operations at dedicated terminals benefit from mitigating characteristics relative to long-distance pipeline transport, including shorter potential release distances, direct operator line of sight, and the ability to enforce controlled access and exclusion zones. The dominant risk profile for truck and barge transfer therefore tends toward high local severity with limited geographic extent, rather than the long-distance plume transport associated with transmission pipeline failures. However, the Satartia incident demonstrates that terrain can still extend a release's reach beyond the immediate transfer point.

Established mitigation practice for CO_2 and comparable liquefied gas transfer operations spans engineering controls, such as pressure-rated hose and loading arm design, emergency shutdown systems, and fixed gas detection near manifolds and low points; operational controls, including standardized loading procedures and weather-awareness hold points during poor dispersion conditions; and emergency preparedness measures, including joint drills between terminal operators and local emergency responders (Det Norske Veritas, 2010; European Industrial Gases Association, 2020; Health & Safety Executive, 2013). This safety dimension is distinct from, but relevant alongside, the cost and regulatory considerations addressed by the decision-support framework developed in this thesis, discussed further in Section 3.7 and Section 5.4.

2.5 Techno-Economic and Decision Drivers for CO_2 Transport Systems

2.5.1 Prior Cost Estimates and Their Limits

Published techno-economic studies provide a useful benchmark against which the results in Chapter 4 can be judged. However, the range across studies is wide enough that no single prior figure should be read as a definitive answer. Most are reported in Euros rather than the dollar figures used throughout this thesis, a currency difference worth noting explicitly rather than obscuring through an

unstated conversion. ZEP (2011) reports pipeline and ship costs of €9.3 and €14 per tonne, respectively, for 2.5 million tonnes per year over 180 kilometers, but at 500 kilometers reports ship as cheaper, €15 per tonne against €20 per tonne for pipeline, illustrating a crossover between the two modes within this distance range. IEA GHG (2004) estimates this pipeline-ship break-even point at approximately 700 kilometers for 6.2 million tonnes per year, a distance that increases at higher annual volumes (Roussanaly et al., 2014). Solomon et al. (2024) find pipeline-only levelized cost ranging from €0.25 to €55.82 per tonne depending on daily mass flow and distance alone, rising to €33.21 to €92.82 per tonne once compression is included, for German pipeline scenarios spanning 25 to 500 kilometers. Smith et al. (2021), using global integrated assessment modeling, find that the widely used flat assumption of $10 per tonne for combined transport and storage cost is reasonable in some regions but not others, and that this assumption measurably affects projected long-term CCS deployment volumes in integrated assessment models, a caution against treating any single published figure, including those cited here, as a universal benchmark rather than a result specific to the distance, volume, currency, and regional cost basis under which it was derived.

2.5.2 Key Cost Components and Scale Effects

CO_2 transport costs are conventionally separated into capital expenditure, front-loaded for pipeline systems given the cost of materials, construction, and right-of-way acquisition but more modular for shipping-based systems, and operating expenditure, driven by energy consumption, maintenance, and labor (Knoope et al., 2013; CO2Tech, 2009; IEAGHG, 2017). This cost structure is not linear with distance across modes, illustrated in Figure 2.3: pipeline cost rises steadily with distance, since pipe material and construction cost scale directly with length, while ship cost rises much more gradually with distance beyond the fixed cost of the vessel and terminal infrastructure, since the marginal cost of additional transit distance is comparatively small once a vessel and port are already committed. This produces a crossover, evident in the ZEP (2011) figures above, at which one mode becomes more economically favorable than the other depending on distance, volume, and utilization; identifying this crossover, rather than treating either mode as universally preferable, is the central problem this thesis's own decision-support framework is built to solve.

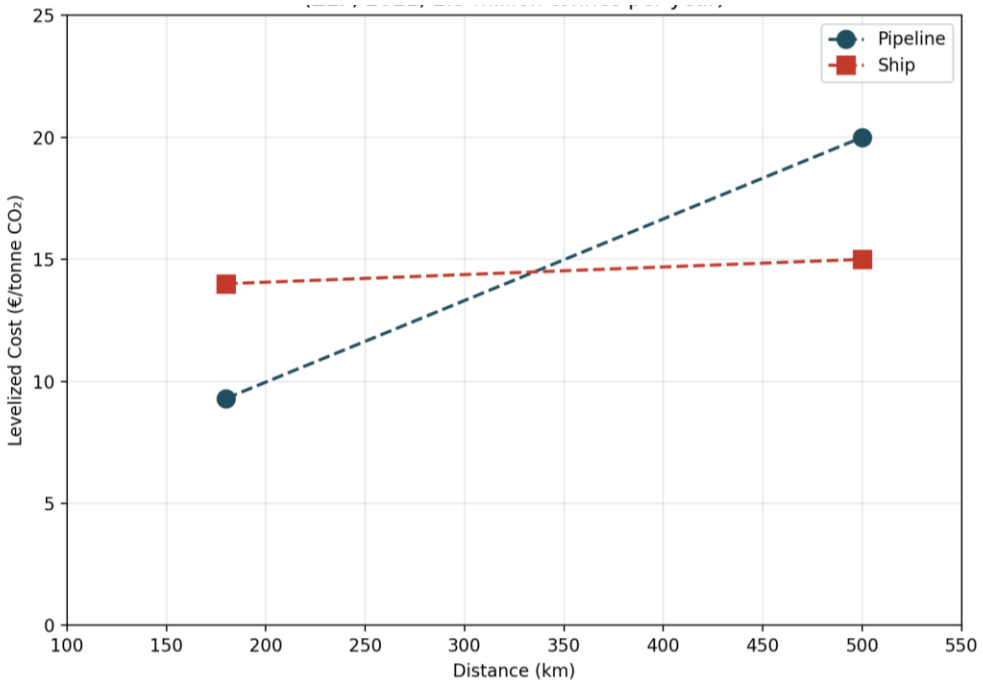

Figure 2.3. Pipeline and ship transport cost by distance (ZEP, 2011).
(Annual volume: 2.5 million tonnes per year). Dashed lines connect the two distances reported in the source and do not represent a continuously verified cost function between them.

2.5.3 Spatial, Regulatory, and Deployment Considerations

Beyond cost and scale, transport system design is shaped by spatial constraints such as terrain, land use, and proximity to existing infrastructure (Sachde, 2021; Gil-Egui, 2025), and by the flexibility and risk profile of each mode. Shipping and other modular transport modes allow systems to be scaled incrementally, reducing financial risk during early-stage deployment when demand is uncertain, while pipelines require longer-term commitment and are correspondingly more sensitive to demand and timing uncertainty (Middleton et al., 2012). These spatial, economic, and temporal considerations cannot be captured through cost analysis alone and together motivate the need for a structured decision-support framework capable of evaluating multiple transport options under varying conditions, integrating the technical, economic, and spatial variables introduced throughout this chapter.

2.6 Regulatory and Permitting Considerations for CO_2 Transport

2.6.1 Overview of Regulatory Frameworks

The deployment of CO_2 transport infrastructure is governed by a complex, multi-layered regulatory landscape that varies across transport modes and jurisdictions (Frattini et al., 2024). These frameworks encompass safety regulation, environmental protection, land use approval, and operational oversight, each of which can significantly influence project feasibility, cost, and timeline.

Unlike technical constraints, regulatory requirements introduce institutional and procedural uncertainties that are often difficult to quantify but can materially affect system design decisions (Vakili et al., 2025). For example, delays in permitting or approval processes can impact project timelines, while regulatory requirements may impose additional design or operational constraints that increase costs.

Importantly, regulatory frameworks are not uniform across transport modes. Pipelines, marine transport, rail, and trucking are each governed by distinct regulatory regimes, resulting in varying levels of complexity and coordination requirements (Frattini et al., 2024). As a result, transport mode selection cannot be evaluated solely on technical or economic grounds, but must also account for regulatory feasibility and approval risk. Real projects illustrate the magnitude of this risk directly. Wolf Carbon Solutions withdrew its proposed 280-mile Iowa-to-Illinois CO_2 pipeline application in 2023 following a state regulatory recommendation to deny the permit, and a comparable Midwest project, Navigator's proposed pipeline, was suspended in Iowa after South Dakota denied siting approval outright (Congressional Research Service, 2025); neither project failed on cost or engineering grounds, illustrating that regulatory risk can end a project regardless of its underlying economics. A federal-waters screening assessment conducted for the GoMCarb project, discussed further in Section 3.5, found that of 20,274 existing pipeline segments screened for potential CO_2 service reuse, only 11 met the full set of technical and regulatory criteria (Dombrowski, Sachde, & Davis, 2021), a concrete illustration of how narrowly regulatory and technical constraints combine to limit an option that might otherwise appear cost-attractive on paper.

2.6.2 Pipeline Regulation and Permitting Challenges

Pipeline CO_2 transport is subject to extensive regulatory oversight, particularly in the United States, where jurisdiction is distributed across federal, state, and local authorities (IEAGHG, 2013). Key regulatory considerations include pipeline safety standards, environmental review processes, and land acquisition requirements, all of which must be addressed prior to construction.

One of the most significant challenges in pipeline development is the acquisition of right-of-way (ROW). Securing continuous land access across multiple parcels introduces both legal and logistical complexities, particularly in regions with fragmented land ownership or competing land uses (Sachde, 2021; Gil-Egui, 2025; IEAGHG, 2013). This process can be time-intensive and may involve negotiations with private landowners, regulatory agencies, and other stakeholders.

Environmental permitting represents another critical barrier. Projects often require compliance with environmental review processes, such as impact assessments and mitigation planning, which can extend project timelines and increase costs (Frattini et al., 2024). These requirements are particularly stringent in environmentally sensitive areas, including wetlands, coastal zones, and protected habitats.

In addition, shoreline crossings and offshore transitions introduce further regulatory complexity. These segments often require additional permits, engineering design considerations, and coordination with multiple agencies, making them disproportionately challenging relative to inland pipeline segments (Sachde, 2021; Gil-Egui, 2025). In coastal regions, these constraints can significantly influence route selection and overall system feasibility.

2.6.3 Regulatory Considerations for Marine Transport

Marine transport's central regulatory requirement is the regulation of CO_2 as a cargo, governing containment, pressure and temperature control, and required safety systems (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022). These requirements influence vessel design, loading and unloading procedures, and storage infrastructure at ports. For inland tank barges specifically, cargo authority is governed by a distinct U.S. Coast Guard review process, separate from the process applied to oceangoing tank vessels, that determines which bulk liquid cargoes a given barge may carry based on its certification subchapter, generating a Cargo Authority Attachment where required (U.S. Coast Guard Marine Safety Center, 2015). Non-flammable bulk liquid cargoes, the category into which CO_2 would fall, are addressed under Subchapters I and O of the applicable federal regulations, subject to density constraints recorded on the vessel's Certificate of Inspection (U.S. Coast Guard Marine Safety Center, 2015). This process is distinct from, and would need to be completed in addition to, any cargo authority review applicable if the same barge were to operate in oceangoing rather than inland service. A separate regulatory requirement, the Jones Act, governs vessel nationality rather than cargo authority: it restricts waterborne transport between U.S. points to vessels that are U.S.-built, U.S.-flagged, and U.S.-

crewed (46 U.S.C. § 55102), a requirement documented to raise vessel construction and operating costs relative to internationally built and crewed alternatives (Cato Institute, 2025). This requirement applies uniformly across the Jones Act fleet. However, its practical cost impact varies by segment: the Congressional Research Service reports approximately 3,500 to 4,000 river barges operating on U.S. inland waterways, compared to only 86 seagoing barges of the articulated tug-barge class discussed in Section 2.7.6 (Benton, 2016), and inland barge operators additionally compete against truck and rail for the same cargo, a competitive pressure largely absent on coastal and oceangoing routes where waterborne transport has few practical substitutes (Cato Institute, 2022).

Port infrastructure itself represents a critical regulatory interface. Developing or modifying port facilities to handle CO_2 requires approval from port authorities and compliance with local, national, and sometimes international regulations (Reyes-Lua et al., 2021). This includes considerations related to safety, environmental impact, and operational compatibility with existing port activities.

Additionally, marine transport may involve cross-jurisdictional or international considerations, particularly when CO_2 is transported across national boundaries or offshore storage sites are located in federal waters (Reyes-Lua et al., 2021). These scenarios introduce additional layers of regulatory coordination, which can affect both project complexity and timeline.

2.6.4 Multimodal Interfaces and Jurisdictional Complexity

Multimodal CO_2 transport systems introduce a unique set of regulatory challenges due to the presence of transfer interfaces between transport modes (ZEP & CCSA, 2022; Gunawan et al., 2024). These interfaces—such as pipeline-to-ship terminals or barge loading facilities—often fall under overlapping regulatory jurisdictions, requiring coordination between multiple agencies.

At these interface points, regulatory requirements must address not only individual transport modes but also system integration, including safety procedures, operational protocols, and infrastructure design (Vakili et al., 2025). This creates additional complexity, as regulations may not be fully harmonized across modes. For example, a pipeline-to-ship transfer facility may be subject to pipeline safety regulations, maritime safety standards, and port authority requirements simultaneously (ZEP & CCSA, 2022). Navigating these overlapping frameworks requires careful planning and coordination, and can introduce additional time and cost burdens.

These multimodal interfaces represent critical points of regulatory friction, where institutional complexity can directly impact system design and feasibility. As a result, regulatory considerations at these interfaces must be explicitly incorporated into transport system evaluation.

2.6.5 Implications for Transport System Design and Decision-Making

Regulatory and permitting considerations play a central role in shaping CO_2 transport system design, often acting as binding constraints rather than secondary considerations (Vakili et al., 2025; Frattini et al., 2024). In some cases, regulatory barriers may outweigh purely technical or economic factors, effectively determining which transport modes are feasible within a given context.

For pipelines, challenges related to right-of-way acquisition, environmental permitting, and shoreline crossings can limit route options and extend project timelines (Sachde, 2021; Gil-Egui, 2025). For marine transport, regulatory requirements related to port infrastructure and maritime operations can influence system design and operational feasibility (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022; Reyes-Lua et al., 2021).

These factors highlight the importance of incorporating regulatory feasibility into techno-economic evaluation frameworks, ensuring that transport mode selection reflects not only cost and performance, but also the likelihood of successful project implementation (Onyebuchi et al., 2018; Middleton & Bielicki, 2009).

In the context of multimodal systems, regulatory complexity further reinforces the need for integrated decision-making approaches that can account for interactions between transport modes and the regulatory environments in which they operate (ZEP & CCSA, 2022).

Despite the significance of these considerations, existing literature often treats regulatory factors as secondary to technical and economic analysis (Onyebuchi et al., 2018). A more comprehensive evaluation approach, one that explicitly incorporates permitting constraints, jurisdictional complexity, and implementation risk into transport system design, remains needed.

Addressing these considerations is particularly important in regions such as the Gulf Coast, where dense infrastructure, extensive waterways, and offshore storage opportunities create a highly complex regulatory landscape that directly influences transport feasibility (Gil-Egui, 2025).

2.7 Gulf Coast Context for CO_2 Transport Systems

2.7.1 Regional Overview and Relevance to CCS Deployment

The U.S. Gulf Coast represents one of the most strategically significant regions for CCS deployment, due to its high concentration of industrial emission sources, existing energy infrastructure, and proximity to large-scale geologic storage resources (Global CCS Institute, 2021; BKV dCarbon High West, LLC, 2024). The region hosts a dense network of refineries, petrochemical facilities, and power plants, many of which are located along the coastline and major inland waterways.

This concentration of emitters creates favorable conditions for CO_2 aggregation and transport, particularly within clustered industrial corridors (Middleton & Bielicki, 2009). At the same time, the Gulf Coast offers access to extensive offshore storage potential, including saline formations and depleted hydrocarbon reservoirs, which are critical for long-term CO_2 sequestration (BKV dCarbon High West, LLC, 2024; Global CCS Institute, 2021).

However, the spatial distribution of sources and sinks introduces a fundamental challenge: while emission sources are often located onshore or along waterways, suitable storage sites are frequently located offshore or at significant distances, requiring the development of integrated transport systems capable of bridging these gaps (Onyebuchi et al., 2018; Middleton & Bielicki, 2009).

Figure 2.4 situates this study within the broader Gulf Coast region before the discussion narrows to the specific infrastructure and storage target considered in this thesis. The figure shows industrial CO_2 point sources, existing CO_2 and hydrogen pipelines, evaluated enhanced oil recovery sites, and offshore saline storage potential across Texas, Louisiana, and Mississippi, illustrating the scale of the broader opportunity within which the Corsair Trough, discussed in the sections that follow, represents one specific study area rather than the full extent of what the region offers.

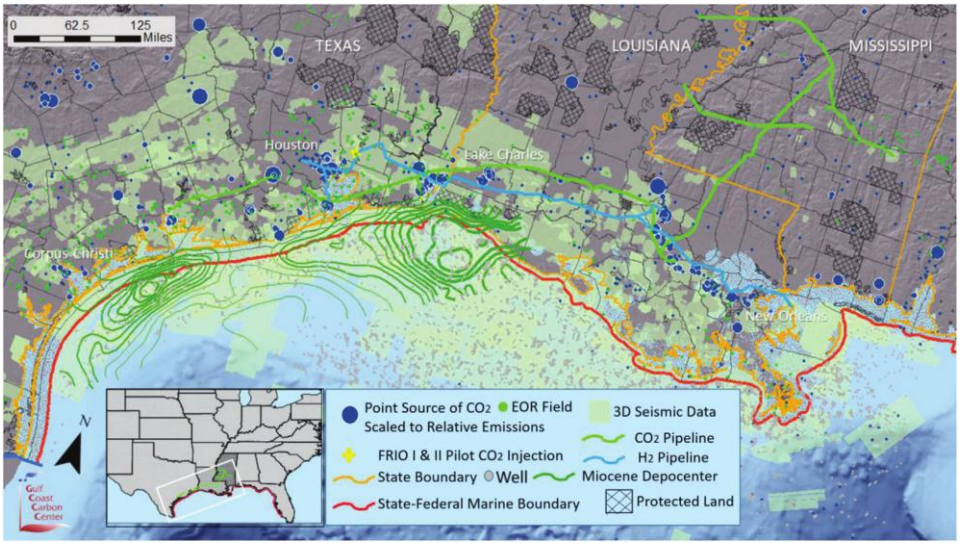

Figure 2.4. Map of the north-western Gulf Coast, showing industrial CO_2 point sources, pipelines, and offshore storage potential.
Texas, Louisiana, Mississippi; sources scaled to relative emissions, with existing commercial CO_2 and hydrogen pipelines, evaluated enhanced oil recovery fields, and offshore saline storage potential shown, with contour thickness indicating relative thickness of Lower Miocene depocenters as a proxy for relative storage capacity prospectivity. Source: Meckel et al. (2021).

As a result, the Gulf Coast provides a representative and highly relevant case study for evaluating multimodal CO_2 transport systems, particularly in the context of offshore storage and complex infrastructure environments.

Figure 2.5 shows the existing transport infrastructure and spatial constraints characterizing this region, including offshore pipelines, storage sites, and the coastal buffers used to bound the emissions inventory for this study.

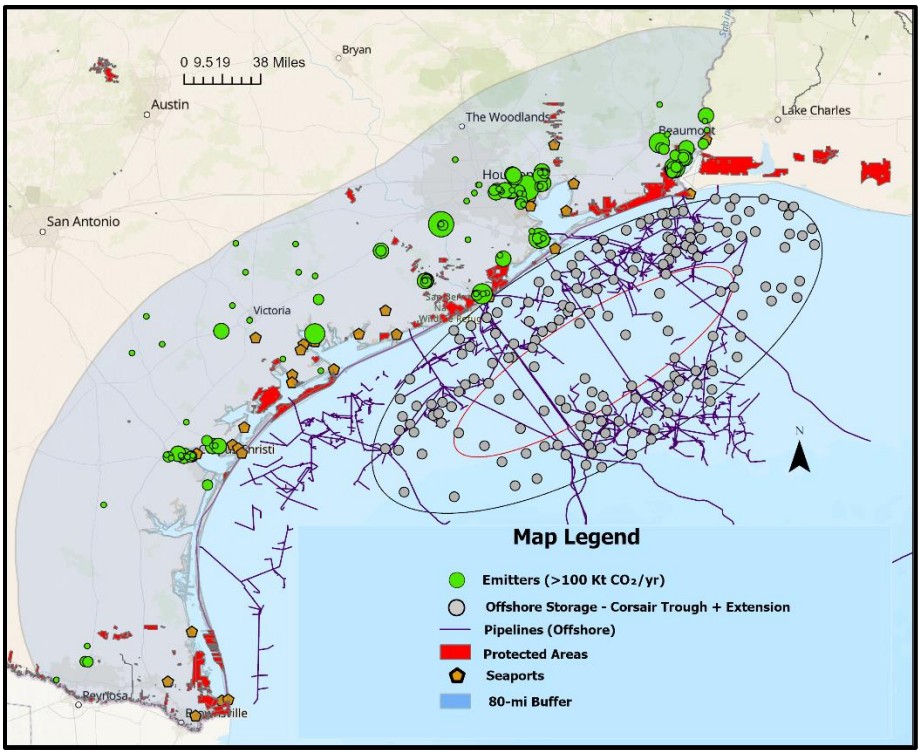

Figure 2.5. CO_2 transport infrastructure and spatial constraints in the U.S. Gulf Coast region. Green circles indicate industrial CO_2 emitters exceeding 100,000 tonnes per year; gray circles indicate individual candidate injection wells within the Corsair Trough and its surrounding extension, the storage target selected for this study and not the only storage option available in the Gulf of Mexico, discussed further in Section 2.7.7. The shaded buffer indicates the inland scoping distance used to bound the underlying emissions inventory, an analytical choice described in Section 3.9 rather than a natural or regulatory boundary.

Figure 2.6 further illustrates the spatial separation between major industrial emitters and candidate offshore storage locations in the Corsair Trough, the geographic condition that motivates the multimodal transport problem addressed by this thesis, this time isolated from the pipeline and protected-area layers shown in Figure 2.5 so that the emitter-to-storage distance itself is easier to see. Chapter 3 revisits this same spatial relationship in greater analytical detail, showing the specific emitter-to-well connection lines underlying the distance calculations used throughout Chapter 4 (Figures 3.3 and 3.4); the maps presented here are intended to orient the reader to the problem before that analysis begins, not to duplicate it.

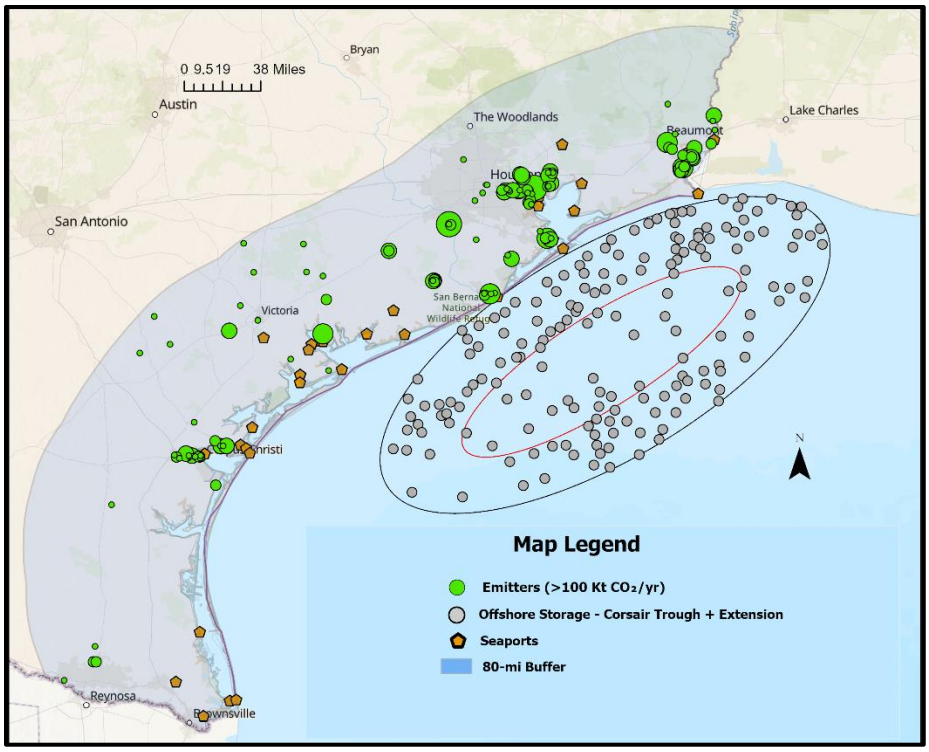

Figure 2.6. Spatial distribution of CO_2 emission sources along the mid-Texas Gulf Coast and candidate offshore storage.
The figure highlights the geographic separation between major industrial emitters and offshore storage target locations in the Corsair Trough.

2.7.2 Existing Infrastructure and Transport Opportunities

The Gulf Coast is characterized by a well-developed energy and transport infrastructure network, including pipelines, ports, inland waterways, and industrial hubs, all of which can influence CO_2 transport system design (IEAGHG, 2013; U.S. Department of Energy, Office of Fossil Energy and Carbon Management, 2024).

The region already contains an extensive network of pipelines associated with oil, gas, and existing CO_2 transport for enhanced oil recovery (EOR) (IEAGHG, 2013). This infrastructure provides a potential foundation for CO_2 transport expansion, although repurposing existing pipelines may be limited by technical, regulatory, or ownership constraints (Vakili et al., 2025).

In addition to pipelines, the Gulf Coast benefits from access to the Gulf Intracoastal Waterway (GIWW), a major inland navigation system that supports barge transport across the region (U.S. Army

Corps of Engineers, 2021). This waterway creates opportunities for barge-based CO_2 transport, particularly for connecting inland emission sources to coastal hubs or offshore export points.

The region's extensive port infrastructure further supports the potential for marine CO_2 transport, enabling connections between onshore capture sites and offshore storage locations (Reyes-Lua et al., 2021). Ports serve as critical nodes within multimodal systems, facilitating transfer between pipelines, barges, and ships (Gunawan et al., 2024). These infrastructure assets collectively create a highly interconnected transport environment, where multiple modes can be combined to support flexible and scalable CO_2 transport systems.

2.7.3 Shoreline Crossings and Offshore Transport Challenges

One of the defining constraints in Gulf Coast CO_2 transport is the challenge of shoreline crossings, which represent critical transition points between onshore infrastructure and offshore storage systems (Sachde, 2021; Gil-Egui, 2025). Pipeline-based shoreline crossings often involve complex engineering and permitting requirements, including environmental impact assessments, coastal zone management compliance, and coordination with multiple regulatory agencies (Sachde, 2021; Gil-Egui, 2025). These crossings can be disproportionately costly and time-intensive compared to inland pipeline segments, making them a key bottleneck in pipeline-based transport systems.

In addition to technical challenges, shoreline crossings introduce heightened regulatory scrutiny, particularly in sensitive coastal environments such as wetlands and estuaries (Sachde, 2021; U.S. Army Corps of Engineers, 2023). These factors can significantly influence route selection, project timelines, and overall feasibility. Marine transport offers an alternative approach to addressing these challenges by enabling CO_2 to be transferred to ships or barges at onshore or nearshore facilities, thereby avoiding the need for continuous pipeline connections across coastal boundaries (Danish Technological Institute & Maersk Broker Advisory Services A/S, 2022; Reyes-Lua et al., 2021). However, this approach introduces its own set of requirements, including port infrastructure, intermediate storage, and transfer facilities.

The trade-offs associated with shoreline crossings therefore play a central role in determining transport mode selection in the Gulf Coast context, particularly when evaluating pipeline versus marine transport options (Sachde, 2021).

2.7.4 Role of Inland Waterways and Barge Transport

The presence of the Gulf Intracoastal Waterway and associated inland navigation systems introduces an emerging opportunity for barge-based CO_2 transport, reflected in recent federal funding for Gulf Coast barge CO_2 transport feasibility studies (U.S. Department of Energy, Office of Fossil Energy and Carbon Management, 2024), consistent with broader industry reporting that tug-and-barge operators are actively repositioning toward emerging energy cargoes, including CO_2, as conventional trades evolve (Hayden, 2026).

Barge transport offers a flexible and potentially cost-effective means of moving CO_2 between inland sources and coastal hubs, particularly in scenarios where pipeline development is constrained by geography, cost, or permitting challenges (BKV dCarbon High West, LLC, 2024; Blue Sky Maritime Coalition, 2024). The modular nature of barge systems allows for incremental scaling, making them well-suited to early-stage deployment or distributed emission sources (Onyebuchi et al., 2018).

However, barge transport is subject to its own set of constraints, including draft limitations, navigational restrictions, and infrastructure requirements at loading and unloading points (BKV dCarbon High West, LLC, 2024). The physical properties of CO_2, including its density in liquid form, can further influence vessel design and operational feasibility. Not all barge configurations are equally suited to every segment of a transport pathway: conventional tug-assisted and push-tow barges are generally limited to protected inland and nearshore waters, while articulated tug-barge (ATB) designs, which use a mechanical coupling engineered to permit pitch while preventing roll and yaw, discussed further in Section 2.3.6, are engineered for coastal and open-water conditions. This distinction has direct implications for which barge configurations can plausibly serve as feeder vessels within protected waterways versus which can undertake an open-Gulf crossing to reach offshore storage.

Despite these challenges, inland waterways represent a strategically important component of multimodal transport systems in the Gulf Coast, enabling connectivity that would otherwise require more complex or costly infrastructure solutions.

2.7.5 Implications for Multimodal System Design

The combination of dense industrial activity, extensive infrastructure, and complex geographic and regulatory conditions makes the Gulf Coast an ideal setting for multimodal CO_2 transport systems

(Middleton & Bielicki, 2009; Gunawan et al., 2024). In this context, no single transport mode is universally optimal. Instead, effective system design requires the integration of pipelines, marine transport, and potentially barge or truck-based systems to address region-specific constraints (Onyebuchi et al., 2018).

Pipelines may serve as the primary mode for high-volume transport within industrial clusters, while marine transport enables connections to offshore storage sites. Barge systems can facilitate movement between inland sources and coastal hubs, particularly where pipeline deployment is limited (Onyebuchi et al., 2018). This layered approach highlights the importance of system-level optimization, where transport modes are selected and combined based on their relative strengths within specific segments of the system (Munkejord, Hammer, & Løvseth, 2016).

Furthermore, the Gulf Coast context underscores the importance of incorporating regulatory constraints, shoreline crossing challenges, and infrastructure availability into transport system evaluation (Sachde, 2021; Gil-Egui, 2025). These factors can significantly influence the feasibility and performance of different transport configurations. As such, the region provides a compelling case for the development of decision-support frameworks that can evaluate multimodal transport options under realistic conditions, accounting for both technical and non-technical factors.

2.7.6 Regional Barge Operating Considerations

The mechanical distinction between conventional tug-assisted or push-tow barges and articulated tug-barge (ATB) designs, introduced in Section 2.7.4, is discussed in full alongside the corresponding ship phase-condition distinction in Section 2.3.6. Regionally, tow configuration and barge sizing vary across the Gulf Coast: routes with greater available towboat horsepower, such as those extending into the Mississippi River system, can support larger or more numerous barges per tow, whereas Gulf Intracoastal Waterway routes typical of the Texas coast tend toward smaller, more frequent tows using towboats in the 2,000 to 4,000 horsepower range (E. Vera, personal communication, 2025).

This distinction has direct implications for the role each barge configuration can play within a CO_2 transport pathway. Conventional barges are well suited to collecting CO_2 from emitters located along protected inland waterways and delivering it to a coastal port or transfer hub, a function analogous to the feeder role played by truck and rail transport described in Section 2.4.6. Articulated tug-barges, by

contrast, are capable of completing the open-Gulf crossing required to reach offshore storage, and are accordingly treated as a primary, long-haul transport option in the framework developed in this thesis, discussed further in Chapter 3.

2.7.7 Storage Target: The Corsair Trough

The Corsair Trough serves as this thesis's storage target throughout Chapters 3 and 4. It is a test case selected to ground the transport comparison in a real, mapped set of offshore wells, not a claim that the Corsair Trough is the only, or the best, storage option available in the Gulf of Mexico. Other candidate storage complexes exist elsewhere along the Texas and Louisiana coast: regional assessments of the federal offshore Gulf of Mexico shelf identify a combined storage resource on the order of tens of gigatonnes of CO_2 across multiple candidate areas beyond the Corsair Trough specifically (Faruqi, 2024; Meckel et al., 2021), and Faruqi's (2024) own regional screening explicitly evaluates and selects among several distinct candidate areas offshore Houston before narrowing to a single site, illustrating that the Corsair Trough is one outcome of this kind of screening process rather than a foregone conclusion. A separate, geographically distinct storage resource exists in Texas state waters, nearer to shore and administratively separate from the federal offshore waters in which the Corsair Trough sits: an atlas-scale assessment of Miocene strata across 109 major oil and gas fields in Texas state waters estimates a depleted-field storage resource of approximately 57.2 trillion cubic feet of CO_2-equivalent, drawn from a broader 181,000-square-kilometer regional dataset spanning the Texas-to-Alabama coast (Treviño & Meckel, 2017). The transport framework developed in this thesis is similarly not specific to the Corsair Trough; it could be applied to any storage target for which comparable well-location data is available. This thesis treats the well locations identified for the Corsair Trough as fixed points for evaluating transport, not as a site characterization exercise in its own right, and relies on separate storage-characterization work for the underlying assessment of the complex's capacity and injectivity.

That separate storage-characterization work is provided by Talen (2026), whose integrated geological, geophysical, petrophysical, and pressure-based assessment of the Corsair Trough forms the basis for the well locations and storage-target framing used throughout this thesis. Talen's analysis, drawing on 177 wells and 25 regional seismic lines across the Corsair Trough and the surrounding extended analog domain, the High Island, Galveston, and Brazos blocks, reports a pressure-limited storage resource of approximately 90 million tonnes of CO_2 under conservative, closed-boundary conditions and

approximately 1,413 million tonnes under open-boundary conditions, together with a base-case single-well injection rate of approximately 1.41 million tonnes per year, roughly double the global average injection rate of approximately 0.7 million tonnes per year (within a reported range of 0.33 to 1.06) that Ringrose and Meckel (2019) derive from historic industry well deployment analogs. These results point to a storage complex with substantial capacity and favorable injectivity, above the global average by this benchmark. However, the wide gap between the closed- and open-boundary estimates reflects real uncertainty in how much lateral pressure communication the sparse well control in the trough can support. Talen's economic analysis further finds that the Corsair Trough's comparatively low legacy-well density, seventy wells within its area of review, compared to several thousand for a representative onshore analog, gives it a meaningful cost advantage at smaller storage volumes, even as offshore transport and infrastructure costs make it less competitive at larger scale. It is this same storage target, and specifically the well locations Talen identifies within it, that this thesis draws on to evaluate the transport side of the problem.

A further simplification concerns the wells themselves. Many of the wells used as candidate injection points in this study are existing oil and gas wells, some of which may be plugged and abandoned, and the associated platforms may no longer be in active service. This thesis does not assess platform age, well condition, or the specific engineering work required to bring a given well into CO_2 injection service; it treats each mapped well location as a candidate injection point without further qualification. Nor does this thesis independently evaluate how much CO_2 any individual well could actually accept beyond citing Talen's (2026) reservoir-specific estimate above: injection rate is a function of reservoir properties, well completion, and formation pressure that varies well to well, and a full treatment of this question lies outside the transport-focused scope of this thesis. The cost of drilling new injection wells, where an existing well is not suitable, is similarly outside this thesis's scope, as is the cost of offloading CO_2 from the transport system into the injection well itself. This thesis is concerned with the segment of the CCS value chain between an emission source and a storage-adjacent transfer point, not with the storage and injection engineering that follows it.

2.8 Literature Gaps and Research Needs

2.8.1 Limitations of Existing CO_2 Transport Literature

Sections 2.1 through 2.7 established that the CO_2 transport literature is genuinely mode-specific and fragmented, with pipeline and marine transport each well studied in isolation but rarely evaluated together within a single, consistent decision framework (Section 2.1.1; Onyebuchi et al., 2018; Middleton & Bielicki, 2009). Two gaps specific to this fragmentation, rather than restated here, are worth drawing together explicitly: existing studies provide limited guidance on how transport options should be combined or sequenced across a real deployment, and much of the literature assumes steady-state, large-scale operation rather than the incremental, evolving volumes characteristic of early-stage CCS deployment (Middleton & Bielicki, 2009). The remainder of this section identifies the specific, additional gaps this fragmentation leaves open, beyond what Sections 2.1 through 2.7 have already established, and that this thesis's own framework is designed to address.

2.8.2 Gaps in Multimodal System Integration

While the concept of multimodal CO_2 transport is increasingly recognized, there remains a significant gap in the literature on system-level integration and optimization (Onyebuchi et al., 2018; ZEP & CCSA, 2022). Existing studies often acknowledge the potential for combining transport modes, but provide limited analysis of how such systems should be designed, operated, or evaluated.

In particular, there is a lack of detailed treatment of transfer interfaces and intermediate storage, which are critical components of multimodal systems (Gunawan et al., 2024). These elements introduce additional technical, operational, and regulatory complexities that are not adequately captured in mode-specific analyses.

Moreover, the operational and logistical challenges associated with coordinating multiple transport modes—such as scheduling, buffering, and system synchronization—are rarely addressed comprehensively (Vakili et al., 2025). This results in an incomplete understanding of the true costs and performance characteristics of multimodal systems.

These gaps highlight the need for research that moves beyond individual transport modes and instead focuses on integrated system design, accounting for the interactions and trade-offs that arise in multimodal configurations.

2.8.3 Limitations in Techno-Economic and Decision Frameworks

Existing techno-economic analyses of CO_2 transport are often limited in their ability to support decision-making across diverse system conditions (Onyebuchi et al., 2018). Many studies focus on optimizing specific transport modes under predefined assumptions, without fully accounting for uncertainty, system evolution, or the potential for multimodal configurations.

In particular, there is a lack of frameworks that explicitly incorporate key decision variables such as transport distance, CO_2 volume, infrastructure constraints, regulatory feasibility, and deployment stage within a unified analytical structure (Middleton & Bielicki, 2009). As a result, decision-making is often based on simplified comparisons that do not reflect the complexity of real-world CCS systems.

Additionally, few studies provide tools or methodologies that can be readily applied to evaluate mode selection under varying scenarios, limiting their practical utility for system planners and stakeholders. What is missing is a flexible, scenario-based decision-support approach capable of evaluating multiple transport options and identifying optimal configurations based on system-specific conditions.

Existing decision-support tools for CO_2 infrastructure planning, such as SimCCS, primarily address pipeline network optimization and source-sink matching, and provide limited treatment of multimodal transport configurations or the mode-selection decision itself (Middleton & Bielicki, 2009). Such tools are well suited to optimizing a pipeline network once a transport mode has been established, but they do not address the prior question of which combination of transport modes is most appropriate for a given set of sources, sinks, and regional conditions. This gap between network optimization and mode selection is a central motivation for the framework developed in this thesis.

2.8.4 Regional and Context-Specific Gaps

A further limitation in the literature is the lack of region-specific analyses that account for local infrastructure, geography, and regulatory conditions (Global CCS Institute, 2021). While global and national-scale studies provide valuable insights, they often overlook the contextual factors that can significantly influence transport system design.

In the Gulf Coast region, these factors include:

- complex shoreline crossing requirements (Sachde, 2021; Gil-Egui, 2025)
- extensive inland waterway systems (BKV dCarbon High West, LLC, 2024)
- proximity to offshore storage sites (BKV dCarbon High West, LLC, 2024)
- dense industrial infrastructure (Global CCS Institute, 2021)
- multi-layered regulatory environments (Frattini et al., 2024)

Despite the importance of these factors, there is limited literature that integrates them into a coherent framework for evaluating CO_2 transport systems. In particular, the role of inland waterways and barge transport remains underexplored, despite their potential to connect inland sources to coastal hubs. This lack of regional specificity limits the applicability of existing research and highlights the need for studies that incorporate real-world constraints and infrastructure conditions into transport system evaluation.

2.8.5 Research Contribution and Positioning of This Thesis

In response to the identified gaps, this thesis develops a system-level framework for evaluating multimodal CO_2 transport options within the Gulf Coast context. The analysis considers pipeline, marine, barge, rail, and truck transport, reflecting the range of modes involved in both onshore and offshore segments of the transport chain. Specifically, this work addresses the following research needs:

- integration of multiple transport modes within a unified analytical framework
- evaluation of transport mode selection under varying distance, volume, and infrastructure conditions
- incorporation of regulatory and spatial constraints into system design
- consideration of system evolution and phased deployment strategies

To support this, the thesis develops a decision-support approach that enables comparison across transport configurations, including pipeline, marine, and multimodal combinations, under different deployment scenarios. Particular attention is given to shoreline crossings, offshore storage access, and the role of intermediate transport modes such as rail and truck in connecting distributed sources to primary transport networks.

By bridging the gap between mode-specific analysis and system-level evaluation, this research contributes to a more comprehensive and practically grounded understanding of CO_2 transport system

design, supporting informed decision-making in the development of CCS infrastructure (Onyebuchi et al., 2018; Middleton & Bielicki, 2009).

CHAPTER 3: METHODOLOGY

3.1 Overview of the Decision-Support Framework

This chapter presents the decision-support framework developed to evaluate CO_2 transport strategies from onshore emission sources in the Texas Gulf Coast to offshore storage in the Corsair Trough. The framework is a techno-economic, threshold-based model rather than a weighted multi-criteria scoring method such as AHP or TOPSIS. This choice reflects the argument developed in Chapter 2: that transport mode selection is governed by transition points at which one mode becomes more cost-competitive than another, rather than by a composite score assembled from independently weighted criteria (Middleton & Bielicki, 2009; Knoope, Ramírez, & Faaij, 2015). A threshold-based model evaluates how distance, volume, project duration, infrastructure availability, and regulatory conditions shift the relative cost-competitiveness of pipeline, marine, and hybrid configurations, rather than reducing these factors to fixed weights applied uniformly across scenarios.

The framework evaluates transport configurations through three integrated layers. A screening layer determines which modes are physically capable of serving a given route. A cost calculation layer computes a levelized cost per tonne for each feasible mode, drawing on a verified parameter library of capital and operating cost data. A regulatory risk layer applies a cost contingency reflecting the permitting complexity and spatial sensitivity of a given route. The framework also models hybrid, multi-segment pathways, in which CO_2 moves from a feeder mode through a transfer hub to a primary long-haul mode, reflecting the multimodal system architecture described in Section 2.4.

This framework is implemented as a structured Excel workbook rather than as custom software, a choice made in consultation with the thesis advisor to prioritize transparency and ease of review. Every formula, parameter, and assumption is directly inspectable, so that reviewing the framework does not require trusting an opaque calculation embedded in code. Spatial inputs, including distances between emitters, coastal landfall points, and storage targets, are derived through a combination of GIS analysis and coordinate-based distance calculation, described in Section 3.8.

3.2 Framework Architecture

This framework distinguishes between primary transport modes and feeder modes. Primary modes are evaluated head-to-head for a given scenario and represent complete long-haul transport options:

onshore pipeline, offshore pipeline (both new construction and requalified existing infrastructure), large articulated tug-barge service, and three ship configurations (small cryogenic, large cryogenic, and small pressurized). Feeder modes, comprising truck, rail, and small or push-tow barge, are not evaluated directly against primary modes. Instead, they represent short local collection segments that connect distributed emission sources to an aggregation point, consistent with the multimodal system architecture in which distributed sources feed a central hub or terminal (Section 2.4; Gunawan et al., 2024).

This distinction reflects the different roles these modes play within a complete transport pathway. Ranking a truck route directly against a full-distance pipeline route would imply that truck is a standalone competitor for the complete source-to-sink journey, which does not reflect its actual function as a short-distance connector. Feeder modes are accordingly modeled within hybrid, multi-segment scenarios (Section 3.6), while the primary comparison reflects only modes capable of serving the complete transport function under evaluation.

A related distinction concerns which barge configurations are treated as primary modes. Push-tow and tug-assisted barges, common on inland and protected waterways such as the Houston Ship Channel, are not designed for open-Gulf sea conditions. Only the articulated tug-barge configuration, which uses a mechanical coupling engineered to permit pitch while preventing roll and yaw, discussed further in Section 2.3.6, is capable of completing an open-Gulf crossing to reach offshore storage. This constraint is treated as a hard screening criterion in the framework, since a vessel that cannot physically complete a route is not a viable option regardless of cost, in contrast to the economic thresholds discussed in Section 3.3, which do not function as hard constraints.

One transport mode considered during framework development, deep-cryogenic rail transport, is excluded from the final analysis. CO_2 is documented as being transported commercially by rail in standard pressure tank cars of the DOT-105 and DOT-112 class, and this mode, Rail-Pressurized, is retained in the framework. A dedicated deep-cryogenic rail tank car class, comparable to the DOT-113 cars used for liquefied natural gas, does not currently exist as a viable commercial option. Equipment of this type is not manufactured at meaningful scale given limited demand. This condition is documented in the liquefied natural gas rail tank car market and is understood to apply similarly to a CO_2-specific cryogenic rail car. Rail-Cryogenic is therefore excluded from the framework as a mode without a viable cost or equipment basis, rather than modeled using speculative figures.

3.3 Screening Logic: Distinguishing Physical Feasibility from Economic Competitiveness

An important distinction in the framework concerns the treatment of distance, volume, and project duration. These parameters describe the conditions under which one transport mode becomes more cost-competitive than another; they do not describe the conditions under which a mode becomes physically or logistically impossible, and the framework treats them accordingly.

This distinction follows directly from the foundational pipeline engineering-economic literature. McCoy and Rubin (2008) demonstrate that pipeline diameter, and therefore cost, is sized continuously as a function of flow rate and target fluid velocity. There is no volume below which a pipeline becomes impossible to construct; there is only a volume below which the resulting small-diameter pipeline becomes cost-inefficient on a per-tonne basis. The same logic applies to distance and duration: a ship traveling beyond its typical breakeven distance against pipeline does not become incapable of making the voyage; it becomes a less cost-competitive option, a distinction the levelized cost formula captures directly.

Distance, volume, and duration thresholds are retained in the framework's parameter library as reference information describing each mode's typical range of cost-competitiveness, rather than as criteria that exclude a mode from consideration. This ensures that a lower-volume or longer-distance scenario is represented as a higher cost per tonne, consistent with the underlying engineering literature, rather than as an infeasible configuration. The only hard, binary screening criterion in the framework is the open-water capability constraint described in Section 3.2, since it reflects a physical limitation rather than a point along a continuous cost curve.

3.4 Cost Modeling Methodology

For each feasible primary mode, the framework computes a levelized cost per tonne of CO_2 transported, combining a capital cost component and an operating cost component.

Table 3.1 summarizes the key cost parameters used for each transport mode, condensed from the complete parameter library reported in Appendix B, including low and high estimates and detailed sourcing notes for every parameter. The capital cost parameter shown for every mode is its reference value at five million tonnes per year, the volume at which each mode's scaling relationship is anchored; at any

other annual volume, the capital cost parameter shown is adjusted according to the volume-scaling relationships described above before entering the cost calculation.

Mode	Cost Basis	Capital Cost Parameter	OPEX Mid	Primary Source
Pipeline – Onshore (New)	Distance-based, volume-scaled	$3.0M per km	$0.0058/t-km	McCoy & Rubin (2008)
Pipeline – Offshore (Existing)	Distance-based, volume-scaled	$1.0M per km	$0.0058/t-km	ACT Acorn (2020); Element Energy (2014); McCoy & Rubin (2008) for scaling
Pipeline – Offshore (New)	Distance-based, volume-scaled	$5.4M per km	$0.0058/t-km	Sachde et al. (2020); McCoy & Rubin (2008) for scaling
Barge – Small (Tug-assisted)	Flat $/t, volume-scaled	$37.5/t	$0.055/t-km	Roussanaly et al. (2021); Vakili et al. (2025) for scaling
Barge – Large (Push Tow)	Flat $/t, volume-scaled	$42.5/t	$0.055/t-km	Roussanaly et al. (2021); Vakili et al. (2025) for scaling
Barge – Large ATB (Coastal)	Flat $/t, volume-scaled	$45.0/t	$0.055/t-km	Roussanaly et al. (2021); Vakili et al. (2025) for scaling
Ship – Small (Cryogenic, Short-haul)	Flat $/t, volume-scaled	$11.25/t	$0.0043/t-km	ZEP (2011); Vakili et al. (2025)
Ship – Large (Cryogenic, Long-haul)	Flat $/t, volume-scaled	$9.30/t	$0.0043/t-km	ZEP (2011); Vakili et al. (2025)
Ship – Small (Pressurized, Short-haul)	Flat $/t, volume-scaled	$5.00/t	$0.0043/t-km	ZEP (2011); Vakili et al. (2025)

Table 3.1. Summary of key cost parameters by transport mode.
Full parameter ranges (low, mid, high) and detailed sourcing notes for every value, including the compression/liquefaction parameters discussed above, are reported in Appendix B (Tables B1 through B3).

For pipeline modes, capital cost is calculated as a function of distance, using a cost-per-kilometer figure amortized over the product of annual throughput volume and project duration, consistent with standard levelized cost treatment (McCoy & Rubin, 2008). This distance-dependent structure reflects that pipeline capital cost scales directly with the length of pipe constructed, consistent with the well-established finding that pipelines are more cost-competitive at shorter distances (IEAGHG, 2013; Knoope et al., 2013). For barge and ship modes, capital cost is treated as an aggregate figure per tonne, consistent with standard shipping-cost literature, in which vessel capital cost is amortized across a fleet's operating life rather than scaled to a single voyage's distance (Roussanaly et al., 2021).

Operating cost is calculated as a per-kilometer rate applied to the distance actually traveled by each mode. Pipeline is capable of direct, door-to-door transport across both onshore and offshore segments, since pipe can be constructed across land and seabed alike. Barge and ship modes cannot cross land, so marine modes are charged only for the marine leg of the journey, from the nearest port to the offshore storage target, with an added feeder-transport cost representing the segment connecting the emission source to the port, using the truck transport rate as the default feeder assumption. This treatment ensures that marine and pipeline costs are compared on a genuinely equivalent, door-to-door basis. Compression and liquefaction infrastructure cost, and the associated energy consumption, are tracked in the framework's parameter library for each mode, drawing on the published cost and energy figures reviewed in Section 3.5, and this cost component, denoted LC(V, T) below, is included in both the transfer-hub cost calculation described in Section 3.6 and the primary single-mode comparison reported in Chapter 4. Section 3.5 reports liquefaction capital and energy costs that are, in some cases, comparable in magnitude to a mode's marine operating cost itself, underscoring why this component is included throughout rather than treated as a secondary adjustment. These relationships can be stated explicitly. This framework applies economies-of-scale cost scaling to the capital cost of every transport mode evaluated in this study, not pipeline alone, since real capital equipment of every kind, pipe, barge, and ship alike, exhibits some form of cost-capacity relationship in which cost per unit of capacity falls as the equipment is sized to carry more. For pipeline modes, levelized transport cost per tonne is calculated as:

$$Cost_{pipeline} = \left[\frac{CAPEX_{per\ km}(V) \times 1{,}000{,}000 \times D}{V \times T}\right] \times (1 + r) + \left(OPEX_{per\ km} \times D\right) + LC(V, T)$$

where:

$CAPEX_{per\ km}(V)$ = the pipeline's capital cost per kilometer in millions of dollars, expressed as a function of annual volume V rather than a fixed rate (Table B2)

D = transport distance in kilometers

T = project duration in years

r = the regulatory risk contingency described in Section 3.7

$OPEX_{per\ km}$ = the per-kilometer operating cost rate in dollars per tonne-kilometer (Table B1)

The bracketed term is the pipeline's capital cost, converted to an equivalent annual charge and divided by annual throughput to arrive at a cost per tonne; distance enters twice, once in the capital term and once in the operating term, since a longer pipeline both costs more to build and more to operate. LC(V, T) is the liquefaction and compression cost component shared by all transport modes, amortizing the capital cost of liquefaction and compression equipment over annual volume and project duration in the same way as the mode's own transport capital cost, plus a fixed per-tonne operating cost for that equipment (Table B2); this component was verified against published sources (Section 3.5) and is included in every cost result reported in this thesis, including the primary comparisons in Chapter 4. Required pipeline diameter is calculated from volume using the continuity relationship between volumetric flow rate, pipe cross-sectional area, and CO_2 transport velocity, following the diameter-sizing approach of McCoy and Rubin (2008); pipeline capital cost is then related to diameter through a power-law cost-diameter relationship, using the capital-cost-weighted average diameter exponent (0.978) implied by McCoy and Rubin's (2008) regression coefficients across their materials, labor, right-of-way, and miscellaneous cost categories. Because pipeline cross-sectional area, and therefore required diameter, scales with the square root of volumetric flow rate, this reduces to:

$$CAPEX_{per\ km}(V) = CAPEX_{per\ km}\left(V_{ref}\right) \times \left(V / V_{ref}\right)^{0.489}$$

anchored at McCoy and Rubin's (2008) own reported reference case of a 100-kilometer, five-million-tonne-per-year pipeline. Below the volume at which this relationship would imply a pipe smaller than the minimum diameter for which McCoy and Rubin's (2008) model is valid (NPS 4), the volume used in this

scaling relationship is held at that minimum-diameter-equivalent volume (339,336 tonnes per year), so the model is not extrapolated into a range the underlying data does not support.

For barge and ship modes, levelized transport cost per tonne is calculated as:

$$Cost_{marine} = CAPEX_{mid}(V) \times DF(T) \times (1 + r) + \left(OPEX_{per\ km} \times D_{marine}\right) + Cost_{feeder} + LC(V, T)$$

where:

$CAPEX_{mid}(V)$ = the mode's capital cost per tonne of annual capacity, expressed as a function of annual volume V rather than a fixed rate (Table B2)

$DF(T)$ = a duration-correction factor that adjusts marine capital cost for the scenario's project duration relative to a mode-specific reference project life, defined below

$OPEX_{per\ km}$ = the per-kilometer operating cost rate in dollars per tonne-kilometer (Table B1)

D_{marine} = the marine-leg distance in kilometers, from the nearest port to the offshore storage target

$Cost_{feeder}$ = the feeder-transport cost connecting the emission source to the port

CAPEX mid(V) reflects that larger vessels achieve lower capital cost per tonne of capacity in the same way larger-diameter pipelines do. This relationship is calibrated using vessel-capacity cost data reported in Vakili et al. (2025), who report a per-tonne shipping cost of £19.35 for a 32,000-cubic-meter vessel and £46.82 for a 7,500-cubic-meter vessel; the implied elasticity of cost with respect to capacity, −0.609, is applied here to annual volume as a proxy for the vessel or fleet capacity a given volume would require, since this framework does not model vessel selection or trip frequency explicitly. Distance itself does not appear in this capital cost term; only volume does, since it is capacity, not route length, that determines vessel or fleet size. This relationship can be stated explicitly, in the same form as the pipeline volume-scaling relationship above:

$$CAPEX_{mid}(V) = CAPEX_{mid}\left(V_{ref}\right) \times \left(V/V_{ref}\right)^{-0.609}$$

As with pipeline, marine capital cost scaling is anchored at a five-million-tonne-per-year reference volume and held constant below a floor of 340,000 tonnes per year, for the same reason.

Marine capital cost, like pipeline capital cost, is also amortized over project duration in this framework, though against a reference project life specific to each mode's underlying cost source rather

than the exact duration tested in a given scenario: forty years for ship, following ZEP's (2011) own stated methodology, and twenty-five years for barge, following standard maritime life-cycle-cost convention, an assumption disclosed as an area of remaining uncertainty in Section 5.4. This correction is calculated as:

$$DF(T) = \frac{CRF(T)}{CRF(T_{ref})}$$

where:

CRF = the standard capital recovery factor, defined below
T = the scenario's project duration
T_{ref} = the mode-specific reference project life

$$CRF(n) = \frac{r(1+r)^n}{(1+r)^n - 1}$$

where:

r = the discount rate, evaluated at the same 8 percent rate ZEP (2011) applies
n = the duration, in years, at which the capital recovery factor is evaluated

A scenario duration shorter than this reference life increases marine capital cost above its reference value, and a longer duration decreases it, the same direction as pipeline's amortization but calibrated to a different baseline; Section 4.5 discusses the resulting duration-sensitivity behavior in detail. Distance enters the marine equation only through the operating term, not the capital term, so a longer marine leg raises marine cost more slowly than an equivalent increase in pipeline distance raises pipeline cost; the practical consequence of this framework's parameters, discussed further in Chapter 4, is that pipeline is least-cost across the full range of Gulf Coast distances and volumes evaluated in this study, while marine transport does not become competitive until distances well beyond this study's Gulf Coast scenarios, consistent with the international comparison discussed in Section 5.2.

Consistent with the disclosures elsewhere in this section, this cost structure excludes several categories of cost that are out of scope for this framework: the cost of CO_2 injection and any per-well constraint on injection rate, discussed in Section 3.9; the cost of offloading CO_2 at the storage site; and the cost of drilling new injection wells. None of these are part of the transport cost this framework is designed to evaluate.

3.5 Verification of Cost Parameters

Cost parameters used in the framework were verified against published sources wherever possible, using one of three approaches: direct citation of a comparable published figure, calibration against a published benchmark result using the framework's own cost formula, or analogical cross-reference to an already-verified parameter representing the same physical state of CO_2.

Pipeline operating cost illustrates the calibration approach. The operating cost rate was derived by solving for the rate implied by two published case-study results reported in McCoy and Rubin (2008): a levelized cost of $1.16 per tonne for a 100-kilometer pipeline transporting 5 million tonnes annually, and $4.06 per tonne for a 200-kilometer pipeline transporting 2 million tonnes annually. Solving for the operating rate consistent with both benchmarks, given the framework's capital cost treatment, produces a rate corroborated against two independent published cases rather than a single source. The resulting framework was verified directly against these benchmark cases, and further cross-checked against a separate published cost figure for a 21-kilometer pipeline transporting 5.12 million tonnes annually in Louisiana (Gunawan et al., 2024), for which the framework's predicted cost fell within a comparable range of the reported figure.

The capital cost of requalifying existing oil and gas pipeline infrastructure for CO_2 service was verified separately from new pipeline construction cost, since repurposing an existing line is a materially different undertaking from building one. The ACT Acorn Project reports that repurposing cost for hydrocarbon pipelines converted to CO_2 service typically falls in the range of 1 to 10 percent of new-build cost (ACT Acorn Project, 2020). A real, documented case, the Longannet CCS project in Scotland, reports an actual repurposing cost of approximately $360,000 per kilometer, excluding compression, for a 280-kilometer natural gas pipeline (Element Energy, 2014). These figures inform the requalified-pipeline capital cost parameter used throughout this framework. Repurposing an existing pipeline for CO_2 service is not solely an economic decision. CO_2 requires substantially higher operating pressure than most natural gas pipelines are designed for, and pipeline design codes require formal re-qualification when the transported product changes (DNV, 2021). This technical and regulatory requirement is reflected in the regulatory profile for requalified pipeline described in Section 3.7. Real precedent for successful repurposing supports the general feasibility of this pathway, including the Tallgrass Trailblazer pipeline in Wyoming, converted from natural gas and now transporting over 10 million tonnes of CO_2 annually,

the OCAP pipeline in the Netherlands, operating in CO_2 service since 2004, and the SONAT pipeline in Mississippi, a 50-mile, 18-inch line converted from natural gas to CO_2 service in 2008 and still in operation, delivering CO_2 to the Cranfield enhanced oil recovery field (Section 3.8). This general feasibility should not be read as evidence that reuse is broadly available across the Gulf Coast pipeline network.

A federal-waters screening assessment conducted for the GoMCarb project evaluated 20,274 pipeline segments against basic reuse criteria, sufficient diameter, operating pressure, out-of-service status, length, water depth, and vintage, and found that only 11 segments met the full set of criteria, a small fraction of the total population screened (Dombrowski et al., 2021). The same assessment identified specific segments found unsuitable on closer inspection, including lines in the shallow waters off High Island that did not meet CO_2 transport requirements and an existing line too small in diameter for the volumes considered without connecting to additional pipe offshore, and noted internal corrosion as a persistent concern for lines decommissioned without corrosion inhibitor treatment. This framework does not have segment-specific reuse feasibility data for the particular pipeline routes evaluated in the Houston, Beaumont, and Corpus Christi clusters, and instead applies a single representative reuse cost parameter, verified in the paragraph above, uniformly across all requalified-pipeline scenarios. Given the Dombrowski et al. findings, this uniform treatment should be understood as a simplification: actual reuse feasibility and cost likely vary segment to segment in ways this framework does not capture, and a route-specific reuse assessment, of the kind conducted for GoMCarb, would be needed to confirm whether a specific existing line along any of this study's routes is actually suitable for CO_2 service.

Ship capital cost requires particular attention to the regulatory context in which vessels operate. Figures drawn from international shipping projects such as Northern Lights in Norway assume internationally built vessels, which does not reflect the cost structure applicable to United States-flagged maritime transport. The Jones Act (46 U.S.C. § 55102) requires that vessels engaged in transport between two points within the United States, including transport to Outer Continental Shelf installations, be built, owned, flagged, and crewed by United States citizens or permanent residents (43 U.S.C. § 1333(a)). Vessels built in United States shipyards cost 300 to 500 percent more than internationally built equivalents (Cato Institute, 2025), and operating a Jones Act-compliant vessel costs an additional $6.2 to $6.5 million annually compared to an internationally crewed vessel, a cost driven primarily by higher domestic crew requirements (U.S. Government Accountability Office, 2018). Both the construction premium and the

crewing premium are incorporated into the framework's ship cost parameters as a fixed per-tonne premium that varies by vessel type, from approximately $6.67 per tonne for the small pressurized vessel used in this thesis's primary scenario comparison to $8.47 and $10.00 per tonne for the large and small cryogenic vessels respectively, reflecting each vessel's specific crew size relative to its cargo capacity, and applied regardless of distance within a given scenario.

The same coastwise requirement applies to the articulated tug-barge evaluated in this thesis, since it too is a Jones Act vessel operating between U.S. points; this framework applies a smaller premium of approximately $2.67 per tonne to the ATB, reflecting its own crew-to-cargo ratio, discussed further in Section 5.4. The feeder-only tug-assisted and push-tow barges evaluated in this framework are not assigned a Jones Act premium, unlike the ATB and ship modes. As discussed in Section 2.6.3, the inland segment of the Jones Act fleet is substantially larger and faces intermodal competition from truck and rail that the coastal and oceangoing segments largely do not, supporting treatment of the inland feeder barge premium as negligible relative to the ATB and ship premiums; this is a simplifying assumption rather than a precisely quantified figure, and is disclosed as such in Section 5.4. Liquefaction and compression equipment costs for cryogenic ship configurations reflect published liquefaction capital cost figures for comparable capacity ranges (io consulting, 2025), rather than the less complete industry estimates available for this category. This identifies a Gulf Coast-specific structural cost disadvantage for marine CO_2 transport that is independent of distance considerations, and that is not captured in international techno-economic literature such as the Northern Lights case.

Where a parameter could not be verified against a directly comparable published source, and where calibration against a benchmark case was not applicable, parameters were cross-referenced across transport modes handling CO_2 in comparable physical states: dense-phase compression without deep refrigeration, deep cryogenic liquefaction, and intermediate semi-refrigerated conditions. Figures were scaled for differences in throughput using the six-tenths rule, a standard cost-scaling relationship in process engineering in which equipment cost scales with the six-tenths power of capacity (Williams, 1947). This approach was applied to align barge transfer-infrastructure costs with the equivalent figures for small pressurized ships, since coastal barges typically carry semi-refrigerated cargo rather than requiring full cryogenic liquefaction, and no directly published cost data exists for CO_2-specific barge transfer equipment.

3.6 Transfer Hubs and Hybrid Pathway Modeling

This framework models hybrid, two-segment transport pathways in which CO_2 moves from a feeder mode, through a transfer hub, to a primary long-haul mode. The transfer hub represents the point at which CO_2 is compressed or liquefied to the condition required by the next transport segment, and where associated transfer infrastructure is located. Hub cost is charged once per hybrid scenario. It is determined by the requirements of the receiving segment, reflecting that compression or liquefaction needs are dictated by the next leg of the journey rather than by the preceding segment.

Three precedents inform the treatment of transfer hubs in this framework and the characterization of hub ownership, operation, and permitting described in response to RQ5 (Section 1.3.2). The Denver City hub in West Texas, where multiple CO_2 pipelines converge for distribution to enhanced oil recovery fields, is a pipeline-to-pipeline hub under vertically integrated ownership. A single operator uses the CO_2 for its own purposes rather than offering transport as a third-party service (Oil & Gas Journal, 2025; Kinder Morgan, 2025). Northern Lights, in Norway, is a mode-transition hub, from marine to pipeline, operated as a merchant service under joint-venture ownership. However, its commercial viability has depended substantially on public funding for its initial phase (Northern Lights JV, 2025). A third precedent is directly relevant to the assumption, used throughout this framework, that emitters need not construct dedicated marine terminals of their own. ExxonMobil's Baytown refinery connects by pipeline to a third-party terminal operated by Oiltanking Partners on the Houston Ship Channel, which simultaneously serves several unrelated refineries through their own pipeline spurs and monetizes shared dock access through third-party throughput fees (Oiltanking Partners, 2012). This precedent supports treating the transfer hub in this framework as a shared, third-party-operated facility rather than infrastructure built and owned individually by each emission source, consistent with an arrangement already operating at scale on the same waterway system relevant to this case study.

A multi-emitter extension of this hub concept, in which the capital cost of a shared hub is allocated across the combined volumes of several participating emitters, was developed as a supplementary analysis, applied to a real, geographically clustered set of emission sources and presented in Chapter 4. Hub capital cost in this extension is scaled for the larger combined throughput using the six-tenths cost-scaling relationship described in Section 3.5, rather than left unscaled at the single-emitter reference figure:

$$HubCost(V) = HubCost(V_{ref}) \times (V/V_{ref})^{0.6}$$

where:

V_{ref} = 547,500 tonnes per year, approximately 1,500 tonnes per day, the single-emitter reference capacity underlying the transfer hub capital cost figures reported in Appendix B

The single-emitter hub mechanism described above remains the framework's primary hybrid pathway mechanism and is applied throughout the case study in Chapter 4; the multi-emitter extension is presented as a supplementary result rather than a fully integrated feature of the primary decision-support tool.

3.7 Regulatory Risk Methodology

Regulatory and permitting considerations are represented in the framework as a risk rating, High, Medium, or Low, rather than as a weighted scoring criterion or a hard exclusion rule. This reflects the finding discussed in Section 2.6 that regulatory factors function as binding constraints on cost and schedule rather than as one criterion to be traded off against cost (Vakili et al., 2025; Frattini et al., 2024). The risk rating is determined by two scenario-specific inputs: whether a proposed route crosses or lies adjacent to a federally protected or environmentally sensitive area, and whether the route requires new federal authorization for offshore infrastructure. These inputs are deliberately mode-generic rather than pipeline-specific, since marine modes face an analogous permitting exposure, port siting and Outer Continental Shelf authorization, even where a shoreline pipeline crossing is not involved.

The regulatory risk rating is translated into a capital cost contingency, using the range of 15 to 30 percent of capital cost specified by the National Energy Technology Laboratory for budgetary-level cost estimates of carbon capture and storage infrastructure (NETL, 2024). Low, Medium, and High risk are mapped to 15, 22, and 30 percent, respectively, using the low end, an approximate midpoint, and the high end of that range. This gives regulatory considerations the capacity to change which transport mode ranks as least cost for a given scenario, a substantive distinction between this framework and pipeline-network optimization tools discussed in Section 2.8.3 that do not incorporate regulatory or spatial risk as a cost-affecting factor.

Regulatory profiles for each transport mode draw on federal regulatory sources: the Pipeline and Hazardous Materials Safety Administration for pipeline safety, the Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement for offshore infrastructure, and the Federal Railroad

Administration and Federal Motor Carrier Safety Administration for rail and truck transport. These are supplemented by a primary-source synthesis of Gulf Coast-specific pipeline permitting pathways prepared as part of the broader GoMCarb project (Gil-Egui, 2025). Offshore pipeline permitting requirements are governed by BOEM and BSEE authorization together with PHMSA safety regulation. The underground injection and storage well itself, which falls under EPA Class VI permitting, is a distinct stage of the carbon capture and storage value chain governed separately from pipeline transport.

This regulatory risk mechanism quantifies permitting and jurisdictional exposure specifically; it is a distinct consideration from the operational safety risk present at transfer points between transport modes, discussed in Section 2.4.7. Operational safety risk during truck and barge CO_2 transfer, characterized in preliminary risk assessment work conducted as part of this research for the GoMCarb project, is not incorporated as a cost-affecting factor in the current framework, an omission acknowledged as a limitation in Section 5.4.

3.8 Spatial Analysis and Distance Estimation

Transport distances are derived from geographic coordinates using the Haversine formula, which computes the great-circle distance between two points on the Earth's surface. For each scenario, three coordinate points are required: the emission source, a landfall or transfer point at the coastline, and the offshore storage target. Onshore and offshore segment distances are calculated separately, allowing distinct cost treatment for each segment.

This approach carries an acknowledged limitation, and the reasoning behind it is worth stating explicitly rather than leaving it for a reader to reconcile against the routing complexity discussed in Chapters 1 and 2. Straight-line distance does not account for real-world routing around property boundaries, terrain, or existing infrastructure, and understates the length of an actual constructed route to some degree. This framework is designed to test the logic of mode selection, the relative cost behavior of pipeline, barge, and ship as distance, volume, and duration vary, across a broad set of scenarios, rather than to engineer a specific, buildable route for any single project. Determining an actual constructed route for even one of the scenarios evaluated in this thesis would require real right-of-way data, environmental survey, and engineering-level routing analysis beyond the scope of a Master's thesis; applying that level of detail to some scenarios and not others would introduce more inconsistency into the comparison across scenarios than the straight-line simplification itself does. Straight-line distance is accordingly applied

consistently across every scenario in this framework, a defensible basis for comparing relative mode competitiveness across many cases, though not a substitute for route-specific engineering analysis of any single proposed project. The specific crossover distances and cost figures reported in this thesis should be read as indicative of relative mode behavior under this consistent simplification, not as a constructed-route cost estimate for an actual project.

Two scenario-specific spatial determinations required direct GIS analysis rather than automated calculation: whether a given route crosses a federally protected or environmentally sensitive area, and identification of a representative coastal landfall point for each emission source. These determinations were made using a filtered version of the U.S. Geological Survey's Protected Areas Database, isolating parcels managed by the U.S. Fish and Wildlife Service and by state fish and wildlife agencies, checked against each scenario's routing corridor using a geometric intersection test in ArcGIS Pro. Emission source coordinates were drawn from the U.S. EPA Facility Level Information on GHGs Tool, and storage-target coordinates from the Corsair Trough well inventory described in Chapter 2, distinguishing between the Corsair Trough core storage area, characterized by comparatively lower well density, and the surrounding, more extensively developed area.

The distinction between these two storage-area boundaries reflects a real geological basis rather than an arbitrary GIS convenience. The Corsair Trough is a large synclinal feature located offshore in the Gulf of Mexico, identified in preliminary scoping work conducted for this research as a promising storage target given its favorable stratigraphy, existing well control, and position within an accessible portion of the Texas offshore domain. The core boundary reflects the trough's structural extent specifically, while the surrounding boundary captures adjacent areas sharing similar depositional and geologic characteristics without being part of the trough itself; the latter is used to provide broader context on nearby well control rather than as an alternative storage target in its own right. Well-log correlation across the trough, sourced from a project collaborator's structural interpretation, indicates that the primary injection interval lies within sand-rich deltaic and slope-apron deposits spanning the Middle Pleistocene to Lower Miocene, bounded by the depth at which CO_2 reaches supercritical conditions, approximately 800 meters, and the top of the regional overpressure zone, on the order of 7,000 to 8,000 feet. These reservoir intervals are laterally persistent across much of the trough but vertically heterogeneous, with the depth to overpressure varying regionally and locally expanding or constraining the effective storage window. This variability supports treating the trough as containing multiple candidate storage zones rather than a single uniform

interval, consistent with this framework's use of two distinct spatial configurations rather than a single storage-target assumption.

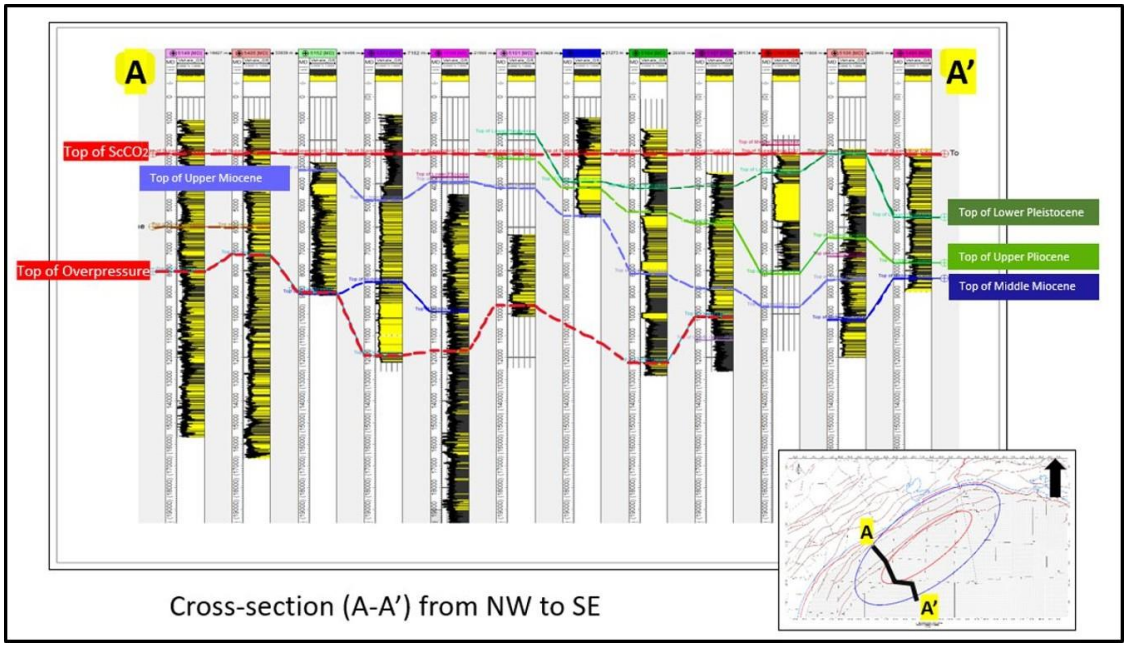

Figure 3.1. Cross-section A–A′ across the Corsair Trough (NW to SE), showing well log correlations and the CO_2 storage window.
Bounded by the top of supercritical CO_2 and the top of overpressure. Sand-prone intervals illustrate both lateral continuity and vertical heterogeneity within the reservoir system (cross-section interpretation by project collaborator Eddie Talen, developed as part of preliminary GoMCarb scoping work for this thesis).

Tie-in feasibility to existing oil and gas pipeline infrastructure was evaluated using a twenty-mile threshold drawn from documented subsea tieback economics (Offshore Magazine, 2018), reflecting the distance beyond which a tie-in generally becomes cost-comparable to independent new infrastructure. This determination could not be made reliably from the available GIS data: the existing pipeline layer for the study area shows fragmented segments serving numerous unrelated platforms and fields, without accompanying data on connectivity, ownership, or available capacity, such that proximity to a mapped segment does not indicate an actual usable tie-in point. This limitation is discussed further in Chapter 5. The existing-pipeline transport pathway modeled in this framework is accordingly presented as an illustrative, lower-bound-cost scenario rather than a site-confirmed option. However, its underlying premise is supported by real precedent for oil and gas pipeline repurposing, including the Tallgrass

Trailblazer pipeline in Wyoming, the OCAP pipeline in the Netherlands, and the SONAT pipeline in Mississippi.

3.9 Case Study Scenario Design

The underlying emissions inventory used in this study is bounded by two inland buffer distances, fifty miles and eighty miles, measured from the Texas Gulf coastline using boundary data from the Texas Natural Resources Information System. These buffers were established during the preliminary GIS scoping phase of the broader GoMCarb project and represent exploratory screening distances rather than engineering or economic cutoffs. The fifty-mile buffer delineates a near-coastal industrial corridor, while the eighty-mile buffer delineates a broader extended-coastal sourcing region that retains plausible access to coastal transport infrastructure. Constructing both buffers allows the framework to evaluate how the available emitter base, potential aggregation opportunities, and the resulting pipeline-versus-marine tradeoffs change as the sourcing radius is expanded, rather than fixing the sourcing region at a single, arbitrarily chosen distance.

Emission sources within these buffers were further divided into two annual emissions categories: facilities emitting 100,000 tonnes of CO_2 per year or more, and facilities emitting 400,000 tonnes of CO_2 per year or more, consistent with thresholds used elsewhere in the CCS literature to distinguish medium- and high-volume industrial sources. These two thresholds serve a distinct methodological purpose from the coastal buffers. Facilities at or above 400,000 tonnes annually are treated as potential anchor emitters: sources large enough to individually justify dedicated transport infrastructure, and the facilities most likely to drive early CCS investment in the region. Facilities at or above 100,000 tonnes represent a broader opportunity set, capturing medium-volume sources that may not individually justify dedicated infrastructure but that could participate in shared transport networks through aggregation, consistent with the multimodal, hub-based system architecture described in Section 2.4. Evaluating both subsets allows the framework to assess how source participation, whether limited to anchor emitters alone or expanded to include medium-volume facilities as well, influences transport mode selection, infrastructure utilization, and network development. This is a central question for a decision-support framework of this kind, rather than a simple inventory of the largest available emitters.

This case study applies the framework to representative scenarios drawn from emission sources in the Houston, Beaumont, and Corpus Christi industrial clusters, spanning both emission-size categories

and, where geographically available, both distance categories. Houston and Beaumont are both situated close to the coastline, and the underlying emissions inventory did not identify additional facilities in either cluster within the eighty-mile buffer that were not already captured within the fifty-mile buffer. The extended-coastal distance category is accordingly evaluated only for Corpus Christi, where a distinct set of facilities falls between the two buffer distances. Representative facilities within each available category were selected based on reported annual emissions from the U.S. EPA Facility Level Information on GHGs Tool.

Scenarios were run against two storage-target configurations to test the sensitivity of results to storage-target selection: the Corsair Trough core storage area, and the broader surrounding area described in Section 3.8. Running both configurations against the same set of emission sources isolates storage-target selection as a distinct variable, since all other scenario inputs are held constant between the two sets.

A separate, controlled comparison was constructed to isolate the effect of transport distance independent of storage-target selection: three emission sources at increasing distances from a single, fixed storage well were evaluated, holding the storage target, project duration, and general scenario structure constant across all three. This comparison directly demonstrates the framework's threshold logic: transport mode cost-competitiveness shifts continuously with distance, without the additional variation introduced by comparing across different storage wells.

Figure 3.2 shows the study area, including the Houston, Beaumont, and Corpus Christi emission source clusters, their corresponding coastal landfall points, and the two storage-target configurations evaluated in Section 4.3.

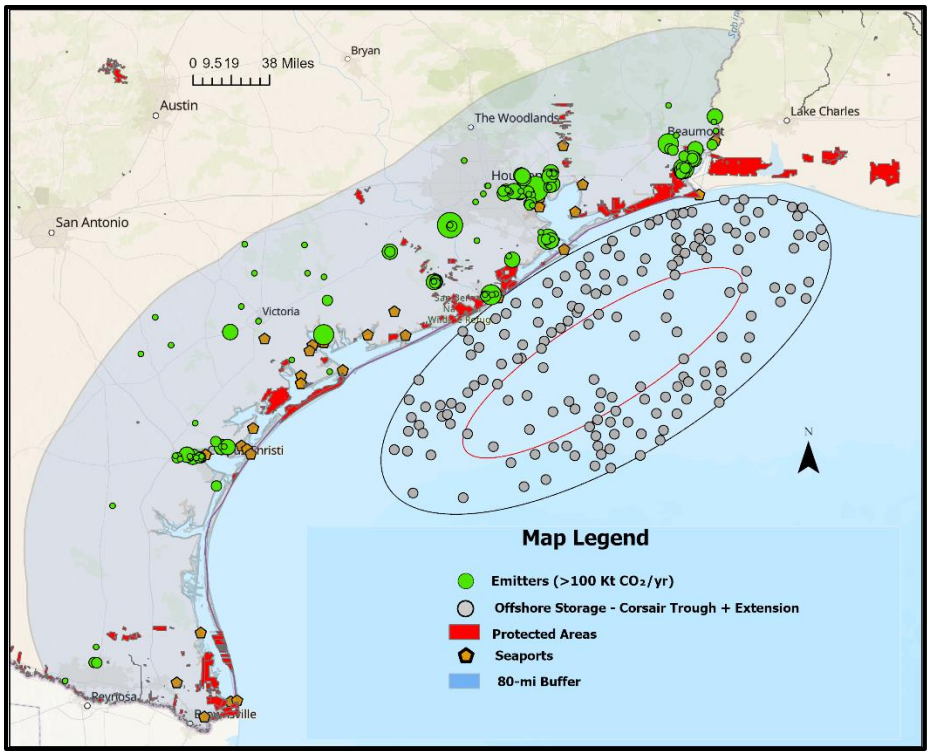

Figure 3.2. Spatial distribution of CO_2 emission sources along the mid-Texas Gulf Coast, protected areas, and candidate offshore storage locations in the Corsair Trough. Author's GIS analysis.

Figures 3.3 and 3.4 show the emitter-to-well connection lines and landfall points underlying the distance calculations described above, for the core and surrounding storage-target configurations respectively. These connection lines are the direct visual counterpart of the Haversine distance calculations described earlier in this section, and the results they inform are presented in Section 4.3.

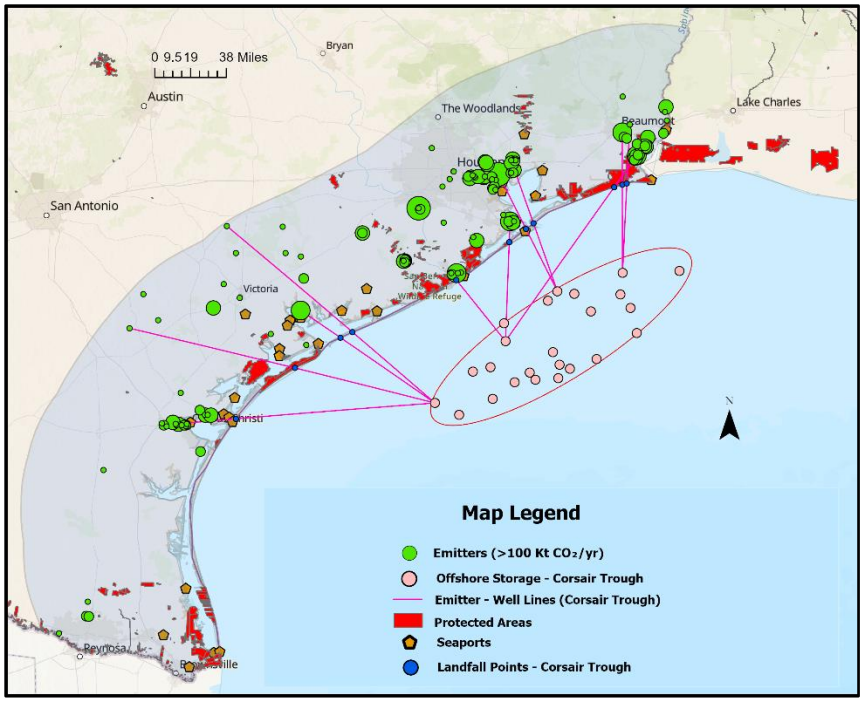

Figure 3.3. Emitter-to-well connection lines and landfall points, Corsair Trough core storage configuration (Author's GIS analysis).

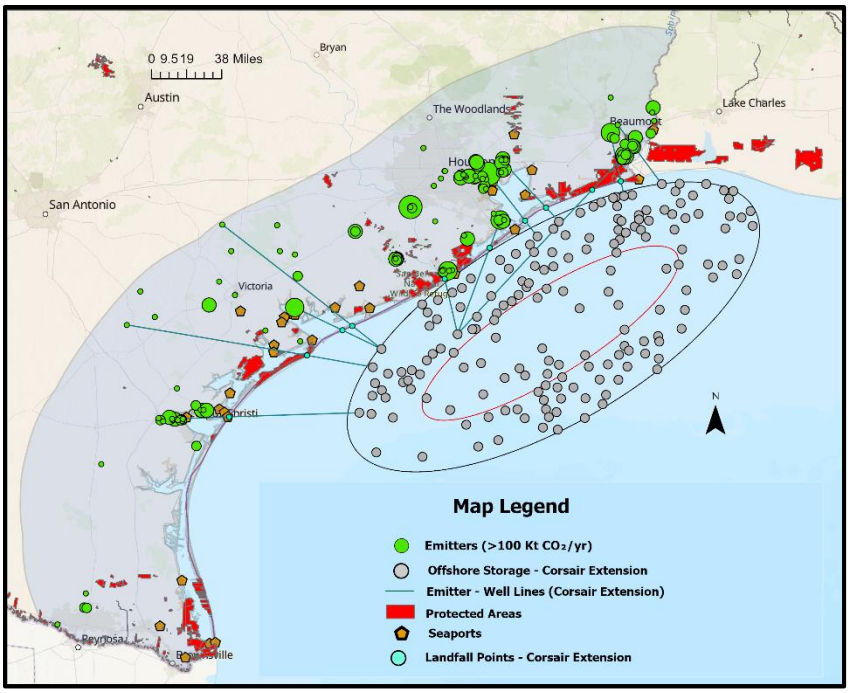

Figure 3.4. Emitter-to-well connection lines and landfall points, Corsair Trough surrounding (extended) storage configuration (Author's GIS analysis).

3.10 Parameter Sensitivity Analysis Methodology

Given that several of this framework's cost parameters carry meaningful uncertainty, discussed in Section 3.5, this thesis includes a sensitivity analysis to determine how much that uncertainty actually affects the framework's central mode-selection result: the distance at which ship becomes least-cost relative to pipeline. A one-at-a-time approach is used, varying each uncertain parameter individually across a defined low-to-high range while holding all other parameters at their central, calibrated value, rather than a full multivariate sensitivity analysis across all parameters simultaneously. This choice reflects the goal of the analysis: identifying which single parameter, if resolved with greater precision, would most change the pipeline-ship crossover distance, a question a one-at-a-time approach addresses directly, whereas a full multivariate analysis would characterize the joint uncertainty across all parameters at once without as clearly isolating which one matters most. Six parameters are evaluated, each with a low-to-high range grounded in a specific source rather than an arbitrary percentage: pipeline capital cost per kilometer varies across the approximately thirty percent regional range reported in McCoy and Rubin (2008); pipeline and ship operating cost rates use the low and high estimates reported in the parameter library (Appendix B); ship capital cost uses the range of distance-dependent capital cost reported in ZEP (2011); and the two volume-scaling exponents introduced in Section 3.4, each derived from a limited number of data points, are assigned an uncertainty band of fifteen percent for the pipeline exponent and twenty-five percent for the marine exponent, reflecting the smaller number of data points underlying the latter. The analysis is repeated at three representative annual volumes, one, five, and ten million tonnes per year, since the volume-scaling relationships introduced in Section 3.4 mean that a parameter's influence on the crossover distance is not necessarily constant across scale. Results are presented and interpreted in Section 4.9.

3.11 Gulf Coast Extension Methodology

As a geographic robustness check on the primary findings in Chapter 4, this framework was applied to real facilities and real storage targets elsewhere on the Gulf Coast, beyond the Houston, Beaumont, and Corpus Christi corridor evaluated in the primary scenarios. Candidate facilities were selected using the same U.S. Environmental Protection Agency Greenhouse Gas Reporting Program data and sector criteria used to identify the primary scenarios' emission sources, extended geographically to Louisiana and Alabama. Three large, real facilities were selected: CF Industries' Donaldsonville Nitrogen

Complex and Marathon's Garyville Refinery, both in Louisiana, and Alabama Power's Barry Electric Generating Plant, on the Mobile River in Alabama, chosen for their combination of large annual volume and genuine geographic dispersion along the coast.

Two storage targets were evaluated for these facilities: the Corsair Trough, the same target used throughout the primary scenarios, and Project Lochridge, a Department of Energy CarbonSAFE Phase II effort assessing offshore CO_2 storage in the South Timbalier Lease Area, selected because it is explicitly designed to serve industrial emitters in and around Geismar, Louisiana, immediately adjacent to Donaldsonville. A supplementary aggregation test was conducted for Donaldsonville and Garyville specifically, given their proximity to one another (35 kilometers); Barry was excluded from this aggregation test, since its distance from the other two facilities exceeds what a genuine local feeder connection would represent.

A final test applies this framework to a real, currently funded Department of Energy front-end engineering design study for an articulated tug-barge system moving CO_2 from a proposed hub at Port Tampa Bay, Florida, to an existing tank terminal at Sunshine, Louisiana, selected because it is a real, publicly documented project using marine transport specifically in a context where no pipeline option exists.

Distances for this extension were calculated as straight-line distances between facility, hub, and storage coordinates, rather than the QGIS-derived corridor distances with explicit landfall points used for the primary Houston, Beaumont, and Corpus Christi scenarios in Chapter 3, and this extension does not apply the protected-area or federal-permitting screening described in Section 3.7. This simplification is disclosed as a limitation in Section 5.4, and this extension is presented as a first-pass geographic robustness check rather than an engineering-grade analysis equivalent in rigor to the primary scenarios. Results are presented and interpreted in Section 4.10.

3.12 Summary

The methodology presented in this chapter operationalizes the multimodal, threshold-based decision logic developed conceptually in Chapter 2 into a structured, transparent, and independently verifiable techno-economic framework. Cost and regulatory parameters used in the framework were checked against verifiable standards, including direct literature citation, calibration against published

benchmark results, and analogical cross-referencing informed by the physical state of CO_2 being handled. The resulting framework and its associated case study results are presented in Chapter 4.

CHAPTER 4: RESULTS

4.1 Overview

This chapter presents the results of applying the decision-support framework described in Chapter 3 to a set of representative Gulf Coast scenarios. The chapter is organized around seven sets of results. Section 4.2 presents the primary transport mode comparison across the full set of scenarios. Section 4.3 examines the sensitivity of these results to the choice of storage target, comparing the Corsair Trough core storage area against the surrounding, more extensively developed area. Section 4.4 presents a controlled comparison isolating the effect of transport distance on mode selection, holding storage target and emission source characteristics otherwise constant. Section 4.5 examines the sensitivity of mode selection to project duration. Section 4.6 presents results from the framework's hybrid pathway modeling, in which CO_2 moves from a feeder mode through a transfer hub to a primary mode, and compares these results to the primary mode comparison in Section 4.2. Section 4.7 presents the regulatory risk sensitivity results. Section 4.8 presents a supplementary analysis of multi-emitter hub cost sharing. Section 4.9 presents a parameter sensitivity analysis identifying which cost parameters most affect the pipeline-ship crossover distance. Section 4.10 extends the framework to real facilities and storage targets elsewhere on the Gulf Coast, as a geographic robustness check on the findings above. Section 4.11 summarizes the key findings and their implications, which are discussed further in Chapter 5.

4.2 Primary Mode Comparison Across Gulf Coast Scenarios

The framework was applied to eight representative scenarios spanning the Houston, Beaumont, and Corpus Christi industrial clusters, each drawn from the emissions inventory described in Section 3.9 and evaluated against the Corsair Trough core storage area. Table 4.1 presents the least-cost transport mode and levelized cost per tonne for each scenario.

Scenario	Total Distance (km)	Annual Volume (t/yr)	Least-Cost Mode	Transport Cost ($/t)
Houston, 400,000+ t/yr, near coast	109.1	12,621,516	Pipeline, Offshore (Existing)	3.03
Houston, ~100,000 t/yr, near coast	117.1	107,905	Pipeline, Offshore (Existing)	27.82
Beaumont, 400,000+ t/yr, near coast	120.3	5,948,714	Pipeline, Offshore (Existing)	3.68
Beaumont, ~100,000 t/yr, near coast	127.2	100,291	Pipeline, Offshore (Existing)	31.47
Corpus Christi, 400,000+ t/yr, near coast	128.3	5,234,689	Pipeline, Offshore (Existing)	3.94
Corpus Christi, 400,000+ t/yr, far ring	217.4	673,133	Pipeline, Offshore (Existing)	11.41
Corpus Christi, ~100,000 t/yr, near coast	196.6	109,099	Pipeline, Offshore (Existing)	39.93
Corpus Christi, ~100,000 t/yr, far ring	238.5	103,482	Pipeline, Offshore (Existing)	48.82

Table 4.1. Least-cost transport mode by scenario, Corsair Trough core storage area.

Pipeline, specifically the requalified existing infrastructure pathway, is the least-cost mode in all eight scenarios. This is consistent with the expectation, discussed in Section 2.7, that pipeline transport is likely to remain dominant in the Gulf Coast given the relatively short distances between emission sources and the Corsair Trough compared to distances typically reported in the broader CO_2 transport literature (BEIS, 2018; Element Energy & UKCCSRC, 2020), and holds even after this framework's volume-dependent capital cost scaling, discussed in Section 3.4, is applied equally to pipeline, barge, and ship.

Table 4.1 includes an extended-coastal, eighty-mile buffer scenario for Corpus Christi only, and not for Houston or Beaumont. As discussed in Section 3.9, this reflects the composition of the underlying emissions inventory rather than an omission: Houston and Beaumont are both situated close to the coastline, and no additional facilities were identified within the eighty-mile buffer for either cluster beyond those already captured within the fifty-mile buffer. Corpus Christi is the only cluster in which a distinct set of facilities falls between the two buffer distances, which is why the extended-coastal comparison is evaluated there specifically.

This result illustrates the threshold logic central to the framework's design. Pipeline capital cost is amortized over the product of annual volume and project duration; at a fixed distance, a smaller annual volume produces a higher pipeline cost per tonne, since the same capital investment is spread across less throughput. Barge capital cost, treated as a flat aggregate figure rather than one that scales with distance in the same way pipeline does, becomes relatively more competitive once pipeline's volume-driven cost penalty is large enough to offset barge's higher per-kilometer operating cost and feeder-transport requirement. No transport mode is universally least-cost across all scenarios, a finding consistent with the central argument developed in Chapter 2.

Figure 4.1 plots levelized cost as a function of distance for pipeline and barge, at the twenty-year project duration used throughout Sections 4.2 through 4.4 and the annual volume corresponding to the Corpus Christi lower-volume scenarios. The barge curve includes the feeder cost component described in Section 3.4, held at the actual feeder distance for this scenario. No crossover occurs within the range of distances plotted: pipeline is least-cost throughout, and the gap between the two modes narrows only modestly as distance increases, from a $334 per tonne difference at 50 kilometers to a $314 per tonne difference at 250 kilometers, since pipeline cost rises with distance as expected while barge's largely volume-driven capital cost component is comparatively insensitive to it. This result is consistent with the

Corpus Christi findings in Table 4.1, where pipeline is least-cost at every scenario evaluated. The effect of varying project duration on this comparison is examined separately in Section 4.5. The pipeline curve's continued rise with distance in Figure 4.1, even for requalified existing infrastructure, is worth noting explicitly: one might expect repurposing an existing line to be a largely fixed, inspection-and-conditioning cost that does not scale much with length. In this framework, however, requalified pipeline capital cost is modeled as a reduced per-kilometer rate rather than a flat charge, since the underlying CAPEX-per-kilometer figure for this pathway (Table B2, Section 3.5) reflects the cost of bringing an existing line into CO_2 service, including internal inspection, cathodic protection assessment, and pressure re-qualification, which this framework treats as scaling with pipeline length rather than as a length-independent fixed cost. The distinguishing feature of the existing pathway relative to new construction is accordingly a lower per-kilometer rate, not a rate independent of distance, and the still-rising existing-pipeline curve in Figure 4.1 reflects this modeling choice rather than an inconsistency in the underlying calculation.

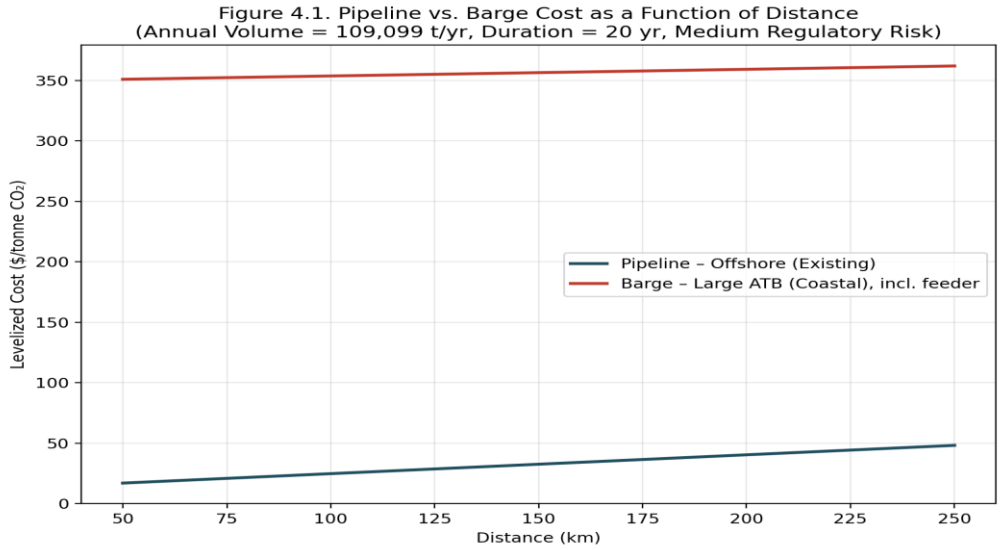

Figure 4.1. Pipeline versus barge levelized cost as a function of distance.
At a fixed twenty-year project duration and the annual volume corresponding to the Corpus Christi lower-volume scenarios. The barge cost curve includes the feeder cost component. No crossover occurs within this range: pipeline is least-cost throughout, and the gap between the two modes narrows only modestly as distance increases.

This narrow gap reflects a structural feature of how marine capital cost is modeled in this framework, worth stating explicitly. Unlike pipeline, whose capital cost scales directly with distance, barge and ship capital cost here depends only on annual volume, not on distance, since it reflects the capacity of the vessel or fleet required rather than a length of infrastructure being constructed; only the

operating cost component, a comparatively small per-kilometer rate, responds to distance for marine modes. This is a simplification rather than a claim that marine transport cost is genuinely insensitive to distance in practice: a longer voyage means a longer round trip, which can require additional vessels or larger capacity to move the same annual volume, an effect on effective capital cost that this framework does not model explicitly, as disclosed in Section 3.4.

A parallel comparison can be drawn between pipeline and ship transport. Figure 4.2 plots levelized cost as a function of distance for pipeline and Ship – Small (Pressurized, Short-haul), the lowest-capital-cost ship configuration considered in this framework, at the same twenty-year project duration and annual volume as Figure 4.1. The ship curve includes the same feeder cost component as the barge curve, plus a flat Jones Act crew-cost premium reflecting the higher operating cost of a United States-flagged, United States-crewed vessel, described in Section 3.5. As with the pipeline-barge comparison, no crossover occurs within this range: pipeline remains least-cost throughout, though the gap between pipeline and ship is considerably narrower than the gap between pipeline and barge, since ship's corrected cost parameters (Section 3.5) are substantially lower than barge's at this scale. This comparison uses requalified existing pipeline, which this framework identifies as the least-cost pipeline option in every scenario evaluated in this study. The comparison looks markedly different if new pipeline construction is used instead: applying the same procedure to new offshore pipeline construction against the same ship configuration, at the same duration and volume, produces a crossover distance of approximately 65 kilometers. This reflects new construction's substantially higher capital cost per kilometer relative to a requalified line, and explains why new pipeline construction is the most expensive mode evaluated in nearly every scenario in Table 4.1: at the distances characteristic of this study's scenarios, all of which exceed 65 kilometers, shipping is the more economical alternative to a newly constructed pipeline, even though existing pipeline infrastructure, where available, remains cheaper than either.

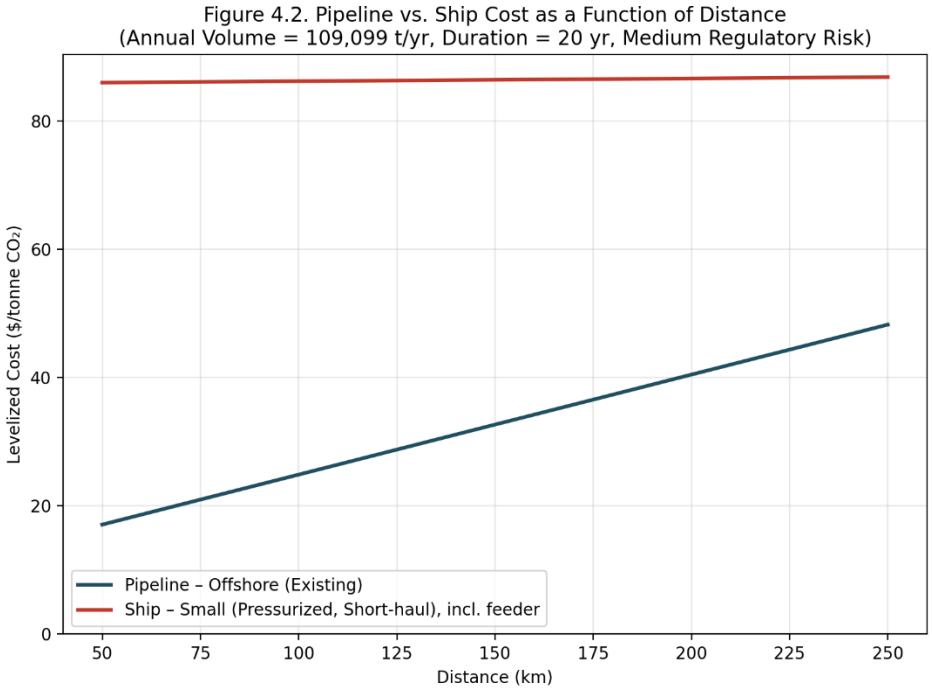

Figure 4.2. Pipeline versus ship levelized cost as a function of distance.
At a fixed twenty-year project duration and the annual volume corresponding to the Corpus Christi lower-volume scenarios. The ship cost curve includes the feeder cost component and the Jones Act crew-cost premium. No crossover occurs within this range: pipeline is least-cost throughout, though by a narrower margin than against barge.

4.3 Sensitivity to Storage-Target Selection

The same eight scenarios were run a second time against the broader area surrounding the Corsair Trough core storage area, described in Section 3.8, to test whether the choice of storage target affects which transport mode is least-cost. Table 4.2 presents these results alongside the corresponding core storage area results for comparison.

Scenario	Corsair Trough: Mode, Cost ($/t)	Surrounding Area: Mode, Cost ($/t)
Houston, 400,000+ t/yr	Pipeline, Existing, 3.03	Pipeline, Existing, 2.45
Houston, ~100,000 t/yr	Pipeline, Existing, 27.85	Pipeline, Existing, 20.22
Beaumont, 400,000+ t/yr	Pipeline, Existing, 3.68	Pipeline, Existing, 2.58

Scenario	Corsair Trough: Mode, Cost ($/t)	Surrounding Area: Mode, Cost ($/t)
Beaumont, ~100,000 t/yr	Pipeline, Existing, 31.42	Pipeline, Existing, 20.24
Corpus Christi, 400,000+ t/yr, near	Pipeline, Existing, 3.93	Pipeline, Existing, 3.00
Corpus Christi, 400,000+ t/yr, far	Pipeline, Existing, 11.41	Pipeline, Existing, 9.23
Corpus Christi, ~100,000 t/yr, near	Pipeline, Existing, 39.89	Pipeline, Existing, 31.68
Corpus Christi, ~100,000 t/yr, far	Pipeline, Existing, 48.91	Pipeline, Existing, 41.25

Table 4.2. Least-cost mode and cost by storage-target configuration.

The least-cost mode identified for each scenario is unchanged between the two storage-target configurations across all eight cases, and the direction of the cost difference is consistent throughout: every scenario shows a lower cost against the surrounding area than against the core storage area, reflecting that the surrounding area lies closer to shore across the emission sources evaluated. Given that cost increases monotonically with distance for every mode in this framework, and that the shift between storage-target configurations changes distance without changing volume or duration, this outcome is not a surprising result in itself; the real question this check answers is one of magnitude, not direction. This result indicates that, for the emission sources and distances considered in this study, the choice between the two storage-target configurations affects the magnitude of transport cost but not the mode selected: pipeline's cost advantage over barge and ship, discussed in Section 4.2, is large enough that the modest shift in offshore distance between the two storage-target configurations does not come close to closing it. This is a useful robustness check on the mode-selection results in Section 4.2, confirming that pipeline's margin over marine transport is not so narrow that a plausible, comparably sited alternative storage target would flip the outcome; it demonstrates that the core finding, requalified existing pipeline as the least-cost mode across the Gulf Coast scenarios evaluated, is not an artifact of the specific storage target chosen, but holds under a materially different set of distances to a comparably sited alternative.

Figures 3.3 and 3.4 in Chapter 3 show the emitter-to-well connection lines underlying these results for the core and surrounding storage-target configurations, respectively, illustrating directly why the surrounding area configuration consistently yields shorter distances across the scenario set.

4.4 Controlled Comparison: Effect of Distance on Mode Selection

To isolate the effect of transport distance from other sources of variation between scenarios, a controlled comparison was constructed using three emission sources at increasing distances from a single, fixed storage well, holding project duration and storage target constant across all three. This comparison was run against both storage-target configurations described in Section 4.3, to confirm that the distance effect holds independently of which configuration is used. Table 4.3 presents these results.

Emission Source	Annual Volume (t/yr)	Corsair Trough: Distance (km), Mode, Cost ($/t)	Surrounding Area: Distance (km), Mode, Cost ($/t)
Olin Blue Cube, Freeport	1,402,548	69.8, Pipeline Existing, 4.14	55.1, Pipeline Existing, 3.71
Galveston Bay Refinery	6,583,677	102.6, Pipeline Existing, 3.31	104.5, Pipeline Existing, 3.34
Motiva Enterprises, Port Arthur	4,962,936	186.6, Pipeline Existing, 5.04	200.8, Pipeline Existing, 5.30

Table 4.3. Controlled comparison of transport distance, fixed storage well, both storage-target configurations.

Pipeline remains the least-cost mode across all three distances and both storage-target configurations in this comparison, consistent with, and not a surprising extension of, the mode-selection results already established in Sections 4.2 and 4.3. The specific, non-obvious result this comparison adds is not which mode wins, but how cost behaves across the three cases: cost per tonne does not increase monotonically with distance across these three cases because annual volume also varies between them. The Galveston Bay Refinery scenario, at an intermediate distance, has the highest annual volume of the three and consequently the lowest cost per tonne. This illustrates that distance and volume act jointly on cost, rather than distance alone determining the outcome, a genuine finding of this comparison rather than a restatement of Section 4.2's mode result. This reinforces the threshold-based framing adopted in this

thesis: transport cost, and by extension mode competitiveness, is a function of the interaction between distance, volume, and duration, rather than any single variable considered in isolation (Section 2.5.3).

4.5 Sensitivity to Project Duration

The scenarios presented in Sections 4.2 through 4.4 all assume a twenty-year project duration. Since pipeline capital cost is amortized over the product of annual volume and project duration (Section 3.4), and barge and ship capital cost is likewise duration-sensitive, corrected against the specific project life assumed by each mode's underlying cost source (Section 3.5), rather than treated as a flat figure independent of duration, project duration is itself a variable capable of shifting which mode is least-cost. This was tested directly using the Houston high-volume scenario and the Corpus Christi lower-volume scenario from Section 4.2, each run at project durations of ten, twenty, and thirty years. Table 4.4 presents these results.

Scenario	10 Years: Mode, Cost ($/t)	20 Years: Mode, Cost ($/t)	30 Years: Mode, Cost ($/t)
Houston, 400,000+ t/yr	Pipeline, Existing, 3.93	Pipeline, Existing, 3.03	Pipeline, Existing, 2.73
Corpus Christi, ~100,000 t/yr, near	Pipeline, Existing, 77.22	Pipeline, Existing, 39.89	Pipeline, Existing, 27.50

Table 4.4. Sensitivity of least-cost mode and cost to project duration.

For the Houston scenario, pipeline cost decreases steadily as duration increases, from $3.93 per tonne at ten years to $2.73 per tonne at thirty years, and pipeline remains least-cost throughout, since its cost advantage over marine transport at this distance and volume is large enough that duration alone does not close the gap. In the Corpus Christi scenario, pipeline is least-cost at every duration tested, and the gap between the two modes narrows, rather than widens, as duration lengthens. Barge cost declines from $507.88 per tonne at ten years to $308.49 per tonne at thirty years, a decline of approximately 39 percent, now that barge's capital cost is amortized against its own reference project life, discussed in Section 3.5, distinct from pipeline's. Pipeline cost declines from $77.22 to $27.50 per tonne over the same range, a proportionally larger decline of approximately 64 percent, since pipeline's entire capital cost is amortized against the exact duration tested in each scenario, while barge's is amortized against a fixed twenty-five-

year reference life; a ten-year scenario falls further below that reference than a thirty-year scenario falls above it, producing a larger swing in barge's cost across this range than in pipeline's. The absolute gap between the two modes nonetheless narrows over this range, from approximately $431 to $281 per tonne, since barge's cost declines by a larger dollar amount than pipeline's does, even though pipeline remains far cheaper throughout and its own percentage decline is larger. This difference in how duration affects each mode's cost remains a genuine finding in its own right: it demonstrates that duration, in addition to distance and volume, materially affects the magnitude of pipeline's cost advantage, even though within the range of durations, distances, and volumes evaluated in this study it does not change which mode is preferred.

Figure 4.3 plots pipeline and barge cost at ten, twenty, and thirty years, using the same cost basis as Figure 4.1. No crossover occurs at any duration tested: pipeline remains least-cost throughout the full range of distances and durations evaluated, and the gap between the two modes narrows notably across duration, from approximately $474 per tonne at ten years to approximately $295 per tonne at thirty years, at a representative 50-kilometer distance. This is consistent with the duration-sensitivity finding in Table 4.4: pipeline's cost declines more steeply than barge's in percentage terms, but barge's cost, now amortized against its own shorter reference project life, declines by a larger dollar amount over this range, narrowing the gap even though pipeline remains far cheaper throughout and this narrowing never produces a mode switch.

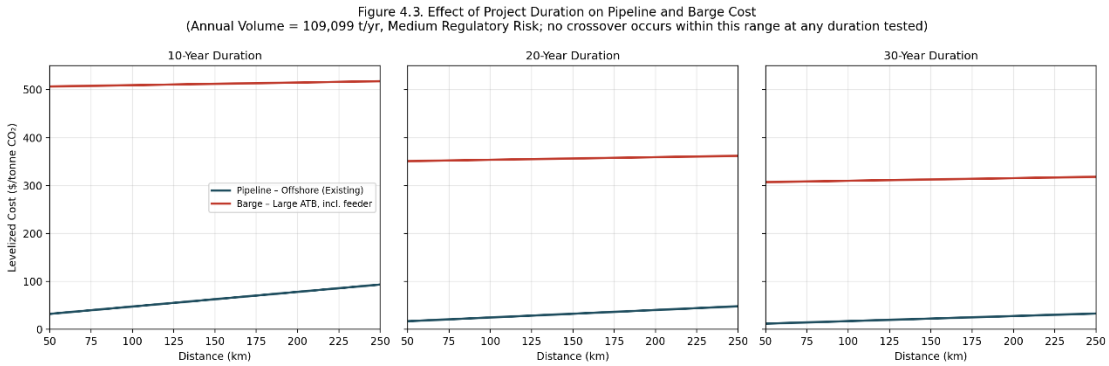

Figure 4.3. Pipeline and barge levelized cost as a function of distance, at ten, twenty, and thirty years. For the annual volume corresponding to the Corpus Christi lower-volume scenarios. No crossover occurs at any duration tested; pipeline remains least-cost throughout. A longer duration lowers both modes' amortized capital cost, but lowers pipeline's overall cost more steeply: pipeline's capital cost is amortized directly over the scenario's own tested duration, so any change in duration proportionally affects the full capital charge, while barge's capital cost is corrected against a fixed twenty-five-year

reference life rather than the exact scenario duration, giving it a comparatively muted response over the ten-to-thirty-year range tested here.

The same duration pattern applies to the pipeline-ship comparison. Figure 4.4 plots pipeline and ship cost at ten, twenty, and thirty years, using the same cost basis as Figure 4.2. No crossover occurs at any duration tested: pipeline remains least-cost throughout, and the gap between the two modes remains roughly stable across this range, unlike the pipeline-barge comparison, since ship's capital cost is amortized against a forty-year reference project life, longer than barge's twenty-five-year reference, giving ship's cost a flatter response to the ten-to-thirty-year range tested here.

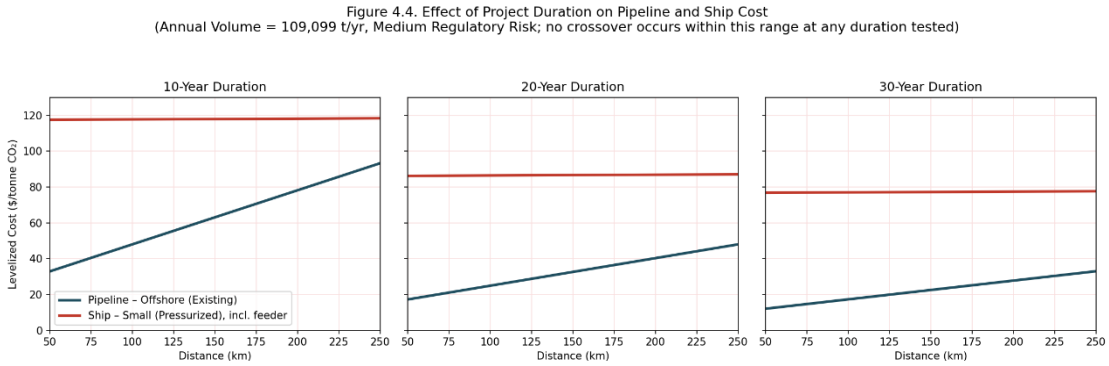

Figure 4.4. Pipeline and ship levelized cost as a function of distance, at ten, twenty, and thirty years. For the annual volume corresponding to the Corpus Christi lower-volume scenarios. No crossover occurs at any duration tested; pipeline remains least-cost throughout, for the same reasons described for the pipeline-barge comparison in Figure 4.3.

4.6 Hybrid Pathway Results

The framework's hybrid pathway mechanism, described in Section 3.6, was tested using four representative feeder-to-primary-mode configurations, applied to the Houston high-volume scenario and both Corpus Christi lower-volume scenarios from Section 4.2, to evaluate how these results compare to the primary mode comparison presented there. Table 4.5 presents these results.

Scenario	Pipeline to Ship ($/t)	Pipeline to ATB ($/t)	Truck to Ship ($/t)	Rail to ATB ($/t)	Primary Mode Result (Section 4.2)
Houston, 400,000+ t/yr	144.10	53.07	166.37	82.22	3.03
Corpus Christi, ~100,000 t/yr, near	250.62	133.46	209.95	100.00	39.89
Corpus Christi, ~100,000 t/yr, far	376.60	256.87	220.93	103.35	48.91

Table 4.5. Hybrid pathway cost by scenario and configuration.

In the Houston scenario, every hybrid configuration tested is substantially more costly than the primary pipeline result. This reinforces the finding in Section 4.2 that pipeline dominates decisively at short distance and high volume, even when compared against configurations that explicitly model a feeder segment and transfer hub rather than the simplified feeder-cost assumption used in the primary mode comparison.

In the two Corpus Christi scenarios, where pipeline remains the least-cost primary mode as in every scenario evaluated in Section 4.2, every hybrid configuration tested is more costly than the primary mode result, including the Rail to ATB configuration, the least costly of the four hybrid pathways tested in both cases. These results indicate that the primary mode comparison's simplified treatment of the feeder segment, which assumes a truck-equivalent cost for the distance between emission source and port, is not an artificially favorable assumption relative to the explicit hybrid alternatives modeled here. If anything, the explicit hybrid configurations tested are more expensive than the primary mode comparison's approximation. This suggests the primary mode results in Section 4.2 are a reasonable, if not conservative, basis for the framework's headline comparison.

4.7 Regulatory Risk Results

Every scenario evaluated in Sections 4.2 through 4.6 returned a Medium regulatory risk rating, and it is worth explaining why, since the mechanism itself is capable of producing High or Low ratings as well, as described in Section 3.7. Two scenario-level inputs determine the rating in this framework:

whether a route crosses a federally protected or environmentally sensitive area, and whether the route requires new federal authorization for offshore infrastructure. All scenarios evaluated in Sections 4.2 through 4.6 were run under the assumption that new federal offshore authorization is required, since none of the routes evaluated could be confirmed as tying into existing offshore infrastructure with available data, discussed in Section 3.8. This single assumption places a Medium floor under the regulatory risk rating for nearly every scenario, regardless of whether the second input, the protected-area crossing flag, varies between scenarios.

To confirm that the mechanism itself is capable of producing the full range of ratings, a single fixed scenario, Houston's 400,000+ t/yr near-coastal facility (12,621,516 t/yr, 109.1 km total distance, first row of Table 4.1), was re-run four times under all combinations of the two regulatory inputs, holding distance, volume, and duration constant throughout. Table 4.6 presents the resulting risk rating and cost for this scenario's overall least-cost mode in each case, alongside the risk rating computed for the offshore pipeline new-construction pathway specifically, which carries the greatest permitting exposure of the modes considered in this framework.

Test Case	Protected Area Crossing	New OCS Authorization Required	This Scenario's Overall Risk Rating	This Scenario's Cost ($/t)	Offshore Pipeline (New) Risk Rating
1	No	No	Low	2.98	Low
2	Yes	No	Medium	3.03	High
3	No	Yes	Medium	3.03	Medium
4	Yes	Yes	Medium	3.03	High

Table 4.6. Regulatory risk sensitivity test, Houston 400,000+ t/yr near-coastal scenario. Fixed at 12,621,516 t/yr, 109.1 km; only the two regulatory inputs vary by row.

In all four test cases, requalified existing pipeline remains the overall least-cost mode for this scenario; only the regulatory inputs change between rows, not the underlying scenario itself.

The overall least-cost mode in every scenario evaluated in this study is either onshore or offshore pipeline using requalified existing infrastructure, and this pathway does not carry the same permitting exposure as new pipeline construction; its risk rating in this test reaches Medium but not High under any

combination of inputs. The offshore pipeline new-construction pathway, by contrast, reaches a High rating whenever the route crosses a protected or environmentally sensitive area, reflecting this pathway's National Environmental Policy Act and Section 106 review exposure, regardless of whether new federal offshore authorization is separately required; a new-OCS-authorization requirement alone, without a protected-area crossing, produces only a Medium rating for this pathway. This confirms that the mechanism is capable of producing the full range of ratings described in Section 3.7. The uniform Medium rating observed for the overall least-cost mode across Sections 4.2 through 4.6 therefore reflects both the conservative new-authorization assumption applied throughout this case study and the fact that requalified existing pipeline, rather than new construction, is consistently identified as least-cost, rather than a limitation of the framework's ability to distinguish regulatory risk. A project relying on new pipeline construction, evaluated under a route that also crosses a protected area, would be expected to show a materially higher regulatory risk rating, and a correspondingly higher cost, under this same framework.

4.8 Supplementary Analysis: Multi-Emitter Hub Cost Sharing

The transfer hub mechanism described in Section 3.6 and applied in Section 4.6 models a single emission source connecting to a shared hub. As a supplementary analysis, this mechanism was extended to evaluate whether pooling several emission sources into one shared hub reduces cost relative to each source connecting independently. Three real, smaller facilities near the Sabine-Neches Waterway served as a test case: Optimus Steel LLC in Vidor, the Orange Carbon Black Plant, and International Paper's Orange Mill, with combined annual emissions of approximately 460,000 tonnes (U.S. Environmental Protection Agency, 2024). These facilities were selected specifically because their access to the Gulf depends on an inland waterway route, via the Sabine River, Sabine Lake, and Sabine Pass, rather than direct open-water access, and because their individual volumes are small enough that each would otherwise bear a substantial per-tonne penalty for building its own dedicated marine transport at that scale.

Both the individual and shared marine leg costs reported here are calculated using the volume-dependent capital cost scaling introduced in Section 3.4: in the individual case, each facility's own, smaller annual volume determines its marine leg cost; in the shared case, the combined volume of all three facilities determines it. The Port of Orange, a real, existing deep-water port on the Sabine River, is used as the shared hub location for this illustrative scenario; each facility's feeder segment reflects its own local

pipeline connection to this hub, using the same feeder cost structure described in Section 3.4. Table 4.7 presents these results.

Facility	Annual Volume (t/yr)	Individual Total ($/t)	Shared Total ($/t)
Optimus Steel LLC	100,291	336.38	282.48
Orange Carbon Black Plant	173,727	323.99	271.13
International Paper – Orange Mill	185,660	325.76	273.01

Table 4.7. Individual versus shared-hub cost, three-facility Sabine-Neches Waterway cluster.

Pooling these three facilities produces a substantial reduction in the marine transport cost each would otherwise bear: individual totals range from approximately $324 to $336 per tonne, while shared totals range from approximately $271 to $282 per tonne, a reduction of roughly 16 percent, reflecting that marine capital cost is properly credited with the same volume-dependent economies of scale this framework applies to pipeline, rather than treated as a flat rate insensitive to volume.

This benefit, substantial as it is in relative terms, does not change the conclusion reached throughout this chapter. Applying the same framework to these three facilities using pipeline instead of barge produces a cost of approximately $18 to $32 per tonne individually, or approximately $9 per tonne if a single shared pipeline connection served the combined volume, in both cases far below even the best-case aggregated marine cost. These facilities were deliberately chosen as a case disadvantageous to pipeline: smaller individual volumes and a location dependent on inland waterway access. Even under these conditions, pipeline's cost advantage, driven primarily by its lower operating cost per kilometer relative to marine transport, remains large enough that the marine aggregation benefit demonstrated here does not approach parity.

As a check on this result, the marine leg distance used above reflects the straight-line distance between the Port of Orange and the Corsair Trough, consistent with the distance methodology used throughout this framework and disclosed as a simplification in Section 5.4. The actual navigable channel distance from the Port of Orange to open Gulf water, via the Sabine River, Sabine Lake, and Sabine Pass, is reported as approximately 37 miles (60 kilometers) by the Orange County Economic Development

Corporation, roughly 19 percent longer than the straight-line distance used here. Substituting this longer, real channel distance raises the marine leg cost only modestly, since the pipeline-barge gap in this scenario is an order of magnitude, not a matter of a few percent. A comparable routing correction has not been applied to the pipeline distances reported here; real pipeline routes are also typically longer than a straight line, an effect this framework does not attempt to quantify.

4.9 Parameter Sensitivity Analysis

The sensitivity analysis described in Section 3.10 applies a one-at-a-time approach to the pipeline-ship crossover distance, testing how much this framework's cost parameter uncertainty, discussed in Section 3.5 and Section 5.4, actually affects that result. Table 4.8 and Figure 4.5 report the resulting swing in crossover distance for each parameter tested, at three representative annual volumes.

Parameters	Low-High Range Basis	Crossover Swing at 1 Mt/yr (km)	Crossover Swing at 5 Mt/yr (km)	Crossover Swing at 10 Mt/yr (km)
Pipeline CAPEX per km	±30% regional variation (McCoy & Rubin, 2008)	1,123 km	1,688 km	2,040 km
Pipeline OPEX rate	Parameter library low/high	245 km	850 km	1,483 km
Pipeline scaling exponent	±15% band around point estimate	389 km	0 km	309 km
Ship CAPEX Mid	ZEP (2011) distance-range low/high	337 km	270 km	241 km
Ship OPEX rate	Parameter library low/high	169 km	597 km	1,047 km
Marine scaling exponent	±25% band around point estimate	330 km	0 km	100 km

Table 4.8. Sensitivity of the pipeline-ship crossover distance to key cost parameters.

One-at-a-time, at three representative annual volumes. Swings are in kilometers; parameters are ranked here as reported, not by influence, since ranking varies by volume.

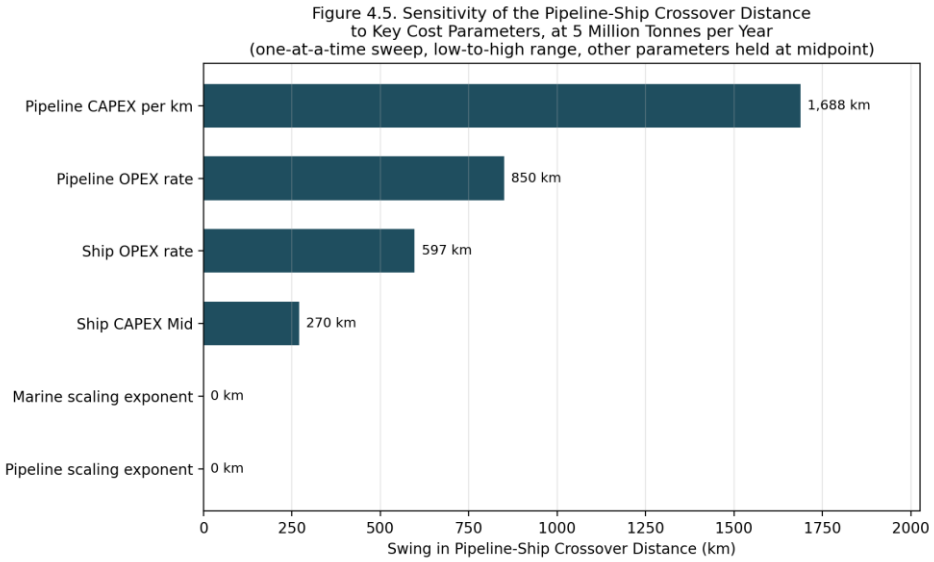

Figure 4.5. Sensitivity of the pipeline-ship crossover distance to key cost parameters, at five million tonnes per year.
Ranked by influence. Pipeline capital cost per kilometer produces the largest swing at this volume, nearly double the next most influential parameter.

The zero swing reported for both scaling exponents at five million tonnes per year is not an error; it follows directly from how the volume-scaling relationships in Section 3.4 are constructed. Five million tonnes per year is the reference volume at which each mode's cost-scaling relationship is anchored, so at that specific volume the ratio of test volume to reference volume equals one, and one raised to any exponent remains one regardless of the exponent's value. The scaling exponents therefore have no effect on calculated cost exactly at the reference volume; their influence only appears once the annual volume being evaluated moves away from that reference point, which is exactly the pattern shown in Table 4.8 at one and ten million tonnes per year.

This result reframes the practical recommendation arising from this thesis. A future front-end engineering design study seeking to sharpen the pipeline-versus-ship decision for a specific Gulf Coast corridor would gain more from confirming the region-specific pipeline construction cost applicable to that corridor than from further refining marine cost parameters, even though marine parameters were the focus of considerably more calibration effort in this thesis. This is not a criticism of that effort: properly calibrated marine parameters remain a prerequisite for this sensitivity analysis to mean anything at all,

since a poorly calibrated marine cost figure would distort the crossover distance regardless of which parameter this analysis identifies as most influential. However, it identifies, concretely and with real numbers rather than general caution, where future effort would be best directed.

4.10 Extension: Gulf Coast Geographic Robustness Check

The scenarios evaluated in Sections 4.2 through 4.8 are specific to the Houston, Beaumont, and Corpus Christi industrial clusters and the Corsair Trough storage target. As a geographic robustness check, using the facilities, storage targets, and methodology described in Section 3.11, this section presents results applying the same framework to real facilities and real storage targets elsewhere on the Gulf Coast, testing whether the pipeline advantage found throughout this thesis is specific to this particular corridor or generalizes more broadly. Applied against the same Corsair Trough storage target used throughout this thesis, pipeline remains least-cost by a wide margin for all three facilities described in Section 3.11: approximately $7 to $13 per tonne, compared to $92 to $122 per tonne for barge and $41 to $45 per tonne for ship.

Facility	Volume (t/yr)	Distance (km)	Pipeline ($/t)	Barge ($/t)	Ship ($/t)
CF Industries Donaldsonville	7,752,762	325.3	6.67	91.61	41.42
Marathon Garyville Refinery	4,177,522	357.2	8.55	114.43	44.31
Alabama Power Barry Plant	4,989,302	625.5	12.94	122.30	44.56

Table 4.9. Louisiana and Alabama facilities versus the Corsair Trough.

A distance-based hypothesis that facilities farther from Texas storage might favor marine transport does not explain this result on its own, since even Barry, at over 600 kilometers, still favors pipeline decisively. A more targeted test uses a real, closer storage alternative: Project Lochridge, a Department of Energy CarbonSAFE Phase II effort assessing offshore CO_2 storage in the South Timbalier Lease Area, explicitly designed to serve industrial emitters in and around Geismar, Louisiana, immediately adjacent to Donaldsonville (U.S. Department of Energy, Office of Fossil Energy and Carbon Management, 2025a).

Against this closer target, distances fall by roughly half, yet pipeline remains least-cost for all three facilities by a similar margin. Louisiana's real, closer storage option does not change the underlying conclusion.

Facility	Distance to Lochridge (km)	Pipeline ($/t)	Barge ($/t)	Ship ($/t)
CF Industries Donaldsonville	140.8	3.80	81.47	40.62
Marathon Garyville Refinery	123.3	4.07	101.56	43.31
Alabama Power Barry Plant	306.3	7.19	104.74	43.19

Table 4.10. The same facilities versus Project Lochridge (South Timbalier Lease Area, offshore Louisiana).

A geographically grounded aggregation test was also conducted. Donaldsonville and Garyville, 35 kilometers apart, were modeled sharing a connection to Project Lochridge; Barry was excluded from this test, since its distance from the other two facilities (270 to 300 kilometers) would require its own long-haul connection rather than a genuine local feeder, undermining the premise of aggregation. At this combined volume, approximately 11.9 million tonnes per year, considerably larger than any scenario evaluated in Chapter 4, pipeline remains least-cost by a wide margin even here: $3.87 to $5.49 per tonne for pipeline, compared to $13.67 to $15.29 per tonne for ship and $47.60 to $49.21 per tonne for barge, gaps of roughly 180 to 250 percent and 800 to over 1,100 percent respectively, consistent with the order-of-magnitude gap found everywhere else in this thesis once the Jones Act premium applicable to both ship and barge is properly included. Scale alone, even at nearly 12 million tonnes per year, does not meaningfully close the gap with pipeline in this framework.

Shared Onward Mode	Donaldsonville ($/t)	Garyville ($/t)
Pipeline – Offshore (Existing)	3.87	5.49
Ship – Small (Pressurized, Short-haul)	13.67	15.29
Barge – Large ATB (Coastal)	47.60	49.21

Table 4.11. Donaldsonville and Garyville sharing a connection to Project Lochridge.

Combined volume approximately 11.9 million tonnes per year.

A final test examines a real, currently funded project that uses barge specifically because pipeline is not an available option, rather than because it is cost-competitive. The Department of Energy has funded a front-end engineering design study for an articulated tug-barge system transporting CO_2 from a proposed multimodal hub at Port Tampa Bay, Florida, to an existing tank terminal at Sunshine, Louisiana, for eventual transfer to permanent storage (U.S. Department of Energy, Office of Fossil Energy and Carbon Management, 2025b). Applying this framework to the real distance between these points, approximately 882 kilometers, at the project's stated volume of two million tonnes per year, produces a result consistent with the rest of this thesis: pipeline would be least-cost, at approximately $24 per tonne, if it were an available option, compared to $181 per tonne for barge and $52 per tonne for ship. The Department of Energy's own project description states the reason barge is used regardless: Florida has no pipeline network capable of transporting captured CO_2 out of state, and no confirmed geologic storage of its own. This is not a case where marine transport is more cost-effective than pipeline; it is a case where pipeline is not a real option at all, consistent with the network-topology explanation this thesis already applies to Northern Lights in Section 5.2, taken to its logical extreme: where no pipeline can plausibly be built, the pipeline-versus-marine cost comparison this framework evaluates does not apply, and marine transport is the only available choice regardless of what it costs relative to an alternative that does not exist.

Mode	**Cost ($/t)**
Pipeline – Offshore (Existing), hypothetical	24.23
Ship – Small (Pressurized, Short-haul)	51.63
Barge – Large ATB (Coastal)	181.39

Table 4.12. Port Tampa Bay, Florida to Sunshine, Louisiana (2 million tonnes per year, approximately 882 km).

Taken together, these results reinforce rather than complicate the central finding of this thesis. Pipeline's cost advantage is not an artifact of the specific Texas corridor evaluated in Chapter 4; it holds for real, large facilities in Louisiana and Alabama, against both the Corsair Trough and a genuine, closer Louisiana storage alternative. The one case where a marine mode approaches pipeline's cost required combining two of the largest CO_2 sources identified anywhere in this thesis, at a combined volume most individual Gulf Coast facilities do not approach. Furthermore, the one real case where marine transport is

actually used instead of pipeline is explained not by cost, but by the complete absence of a pipeline option, a structural condition this framework is not designed to represent and does not need to in order to remain consistent with what is actually built.

4.11 Summary of Key Findings

This chapter presents eight sets of findings. First, pipeline transport, particularly requalified existing infrastructure, is the least-cost option in all eight Gulf Coast scenarios evaluated, reflecting the relatively short distances between Gulf Coast emission sources and the Corsair Trough, and holding even after this framework's volume-dependent capital cost scaling, discussed in Section 3.4, is applied equally to pipeline, barge, and ship. This demonstrates that pipeline's advantage in this study is not an artifact of an unfairly simplified marine cost treatment, illustrated directly in Figure 4.1.

Second, the choice between the Corsair Trough core storage area and the surrounding area affects the magnitude of transport cost, with every scenario showing a lower cost against the surrounding area given its closer proximity to the emission sources evaluated. In all eight scenarios tested, this does not change the identity of the least-cost mode. This indicates that the mode-selection results presented in Section 4.2 are robust to the specific storage target chosen within the Corsair Trough area, and that pipeline's cost advantage over marine transport is large enough across the distances evaluated in this study that the modest shift in offshore distance between the two storage-target configurations does not close the gap.

Third, the controlled comparison in Section 4.4 confirms that transport cost is a function of the interaction between distance and volume rather than either variable considered independently, and that pipeline remains least-cost across the full range of distances tested in that comparison, given the volumes involved, and holds under both storage-target configurations.

Fourth, project duration is a genuine third dimension of the framework's threshold behavior, alongside distance and volume, even though it does not change which mode is preferred within the range evaluated in this study. The duration sensitivity analysis in Section 4.5 shows that pipeline's cost declines much more steeply with duration than barge's does, since pipeline's capital cost is amortized directly over the scenario's own tested duration while barge's is corrected against a fixed twenty-five-year reference life, giving barge a comparatively muted response, illustrated directly in Figure 4.3. This demonstrates

that a mode's cost, though not necessarily which mode is preferred, cannot be evaluated independently of the assumed project duration.

Fifth, explicit hybrid pathway modeling, in which a feeder segment, transfer hub, and primary mode are modeled individually rather than approximated, produces higher costs than the primary mode comparison in every configuration tested, for every scenario tested. This indicates that the primary mode comparison's simplified feeder-cost assumption is not producing artificially favorable results for either pipeline or marine transport, and that the mode-selection findings in Section 4.2 hold up under a more detailed representation of the transport pathway.

Sixth, the regulatory risk sensitivity analysis in Section 4.7 confirms that the framework's regulatory risk mechanism produces its full range of ratings, Low, Medium, and High, depending on scenario conditions. The uniform Medium rating observed for the overall least-cost mode across this study's scenarios reflects this case study's conservative assumption regarding new federal offshore authorization and the consistent selection of requalified existing pipeline as least-cost, rather than a limitation of the mechanism itself.

Seventh, the supplementary multi-emitter hub analysis in Section 4.8, using a real cluster of three facilities near the Sabine-Neches Waterway, shows that pooling geographically clustered emission sources into a shared transfer hub and shared marine leg produces a substantial reduction in each facility's overall total cost, approximately 16 percent, once the marine leg is properly credited with the same volume-dependent economies of scale applied elsewhere in this framework. However, it does not change the identity of the least-cost mode: pipeline remains substantially cheaper than even the aggregated marine option for this cluster.

Eighth, a geographic robustness check in Section 4.10, applying this framework to real facilities and real storage targets in Louisiana and Alabama, confirms that pipeline's cost advantage holds broadly beyond the Texas corridor evaluated above, including against a real, closer Louisiana storage alternative. The one case in which a marine mode approaches pipeline's cost involves aggregating two large Louisiana facilities at a combined volume far exceeding any single scenario evaluated in this chapter, and even then pipeline remains least-cost. A separate case, a real Florida-to-Louisiana barge project, is explained by the complete absence of a pipeline option in that location rather than by relative cost, consistent with this

framework's own cost logic. The implications of these findings for CO_2 transport planning in the Gulf Coast are discussed further in Chapter 5.

CHAPTER 5: DISCUSSION AND CONCLUSION

5.1 Overview

This chapter interprets the results presented in Chapter 4 in relation to the research questions and contributions outlined in Chapter 1, discusses the limitations of this study, identifies directions for future research, and summarizes the contributions of this thesis to CO_2 transport planning in the Gulf Coast and to CCS infrastructure planning more broadly.

5.2 Implications for Transport System Design

The results in Chapter 4 support a clear finding: within the range of distances, volumes, and durations evaluated for this thesis, requalified existing pipeline is least-cost across every Gulf Coast scenario tested, reflecting the relatively short distances between the Houston, Beaumont, and Corpus Christi industrial clusters and the Corsair Trough compared to distances typical of the international CO_2 shipping literature. This finding is consistent with the general expectation in the literature that pipelines dominate at shorter distances and higher volumes (Section 2.5.3), and the volume-dependent capital cost scaling developed in Section 3.4, applied to pipeline, barge, and ship alike, extends that expectation by showing that pipeline's advantage holds even after correcting for the same kind of scale-dependent capital cost effects that would be expected to benefit marine transport at smaller scale. The Jones Act cost premium identified during framework development (Section 3.5) reinforces this finding independently of distance: maritime CO_2 transport between United States points carries a cost disadvantage, arising from both vessel construction and crewing requirements, that is not present in the international projects most often cited in the CO_2 transport literature. This suggests that findings drawn from projects such as Northern Lights should be applied to a United States Gulf Coast context with caution, since a structural cost factor specific to domestic maritime transport is otherwise easily overlooked.

This does not mean marine transport is irrelevant to Gulf Coast CO_2 transport planning, even though it is not cost-competitive with pipeline within any scenario evaluated in this study. The international comparison presented below demonstrates that this framework's cost logic, once corrected for realistic capital cost scaling in both pipeline and marine modes, predicts marine transport's advantage at distances well beyond this study's Gulf Coast range, consistent with real-world project choices at that scale. Within the Gulf Coast itself, the case for marine transport may rest less on per-tonne cost parity with pipeline and more on the network-topology considerations discussed above: aggregating dispersed,

smaller emission sources onto a shared marine terminal may be attractive where connecting each source individually to a shared pipeline corridor is not feasible, independent of whether marine transport is cost-competitive with pipeline on a per-tonne basis alone. A practical implication for CO_2 transport planning is that smaller or more distributed emission sources, of the kind captured in the 100,000 tonne per year category defined in Section 3.9, are the sources for which aggregation is worth evaluating as an alternative to a dedicated transport solution sized to their own volume alone. The supplementary hub-sharing analysis in Section 4.8 offers an initial, bounded demonstration of this benefit for one illustrative cluster of nearby facilities. However, it has not been tested broadly enough across this study's scenarios to establish how generally the benefit holds. This study's own hub-sharing results find that aggregation reduces cost without changing which mode is preferred. This aggregation can take the form of either a shared pipeline corridor or a shared marine terminal.

The hybrid pathway results in Section 4.6 add a further, complementary implication. Explicit modeling of a feeder segment, transfer hub, and primary mode consistently produced higher costs than the simplified feeder-cost treatment used in the primary mode comparison, for every scenario and configuration tested. This suggests that aggregation, where it is pursued, should be structured to minimize the number of distinct mode transitions in a pathway rather than treated as costless. Each additional transfer hub introduces both a capital cost and, as discussed in Section 3.6, a governance question regarding hub ownership and operation that does not arise for a single-mode pathway.

This caution can be examined directly by applying the framework's cost structure to the distance and volume profile of two real international projects. Doing so requires an important caveat: nearly all of the framework's cost logic, including the volume-dependent capital cost scaling described in Section 3.4 and the amortization of capital cost over volume and duration, is general engineering-economic modeling rather than content specific to the Gulf Coast. The only genuinely Gulf Coast-specific elements are the two regulatory screening flags and the Jones Act crew-cost premium, and neither materially affects the results discussed below.

Northern Lights transports CO_2 by ship over approximately 320 kilometers from Brevik to a receiving terminal at Øygarden, then by a roughly 100-kilometer subsea pipeline to the Aurora storage reservoir (Equinor, 2025; TotalEnergies, 2025), as shown in Figure 5.1. That combined distance and annual volume, 1.5 million tonnes in its first phase, run through this framework's cost structure, still favors

pipeline over ship for the entire route. Northern Lights nonetheless uses ship for the long-haul segment. The framework's single-corridor cost logic does not explain this: Northern Lights is designed to receive CO_2 from multiple emitters across different European countries, none of which share a pipeline corridor with Norway, so ship transport allows each emitter to reach a common terminal independently, avoiding the construction and multi-jurisdictional permitting of an international pipeline network. The short pipeline segment from that shared terminal to the storage site then behaves as a conventional single-owner tie-in, consistent with this framework's own finding that pipeline is preferred at short distances.

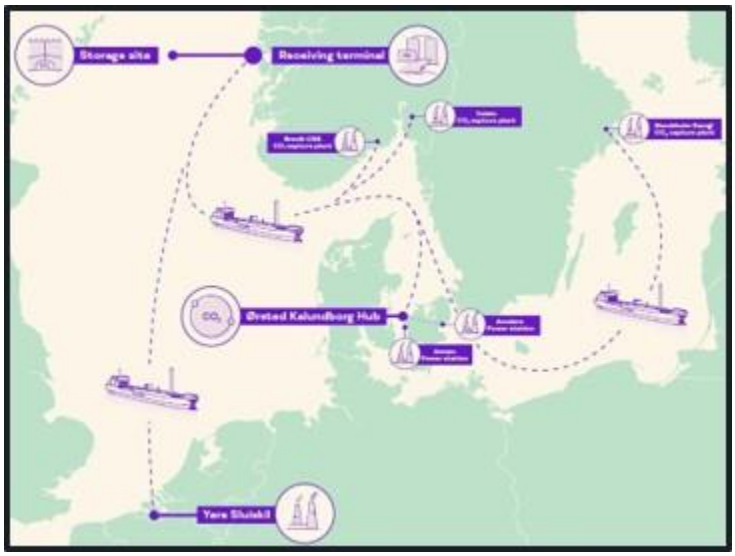

Figure 5.1. Schematic of the Northern Lights CO_2 transport system, showing cross-border marine transport.
CO_2 is transported from distributed European emission sources to a central receiving terminal and offshore storage. Source: Northern Lights, 2023.

The proposed Japan-Australia CO_2 shipping arrangement illustrates a case where this framework's cost structure and the real-world outcome now agree. Applying the framework's cost structure to the roughly five-thousand-kilometer distance between Nagoya and Australia's Bonaparte Basin (INPEX Corporation, 2024), at a representative annual volume of ten million tonnes, produces a result consistent with the actual project: ship, at approximately $62 per tonne, is least-cost, against approximately $77 per tonne for requalified existing pipeline. This is a meaningful validation of the volume-dependent capital cost scaling introduced in Section 3.4 for both pipeline and marine modes. Without this correction, using a flat, unscaled per-tonne marine capital cost would implausibly favor pipeline even at this scale, a result inconsistent with the crossover distance reported across the broader CO_2 transport literature, in which ship

becomes competitive with pipeline somewhere in the range of roughly one thousand to fifteen hundred kilometers at lower annual volumes (ZEP, 2011). This framework's corrected cost structure produces a longer crossover at this volume, approximately 3,350 kilometers, discussed further in the sensitivity analysis in Section 4.9, reflecting this framework's own cost parameters rather than a direct match to the literature range cited above; the Japan-Australia case, at roughly 1.6 times that distance, still falls within the region where ship is expected to win.

Together, the two cases illustrate a useful contrast. Japan-Australia shows that, once marine capital cost is properly scaled to reflect real vessel economics, this framework's cost logic alone is sufficient to explain long-distance mode selection. Northern Lights shows that cost logic alone is not always sufficient: even at a distance well within pipeline's advantage under this framework's cost structure, network topology, the need to connect multiple dispersed international emitters without a shared pipeline corridor, can still favor ship. Both considerations, cost and network topology, matter for real-world mode selection at intercontinental scale, and this framework's contribution is to make the cost dimension explicit and testable, not to claim it is the only consideration relevant to how CO_2 transport systems are actually built.

5.3 Implications for Regulatory Considerations

The regulatory risk results in Section 4.7, in which every scenario returned a Medium rating driven by the assumption that new federal offshore authorization is required throughout, illustrate a broader implication for CO_2 transport planning in the Gulf Coast. The availability of existing offshore infrastructure suitable for tie-in is likely to be as consequential for project cost and schedule as the choice of transport mode itself. This framework’s regulatory risk mechanism was designed, and independently verified, to distinguish between routes of differing regulatory exposure; that every scenario in this particular case study returned the same rating reflects a conservative, uniform assumption applied across all scenarios rather than a limitation of the underlying mechanism. A project developer with a confirmed existing offshore tie-in, or a route that does not cross a federally protected area, would be expected to see a materially different, and more favorable, regulatory risk outcome under this same framework.

A related but distinct point concerns the qualitative regulatory pathway each mode navigates, summarized in Table B3. Pipeline segments are governed by PHMSA safety regulation together with BOEM/BSEE offshore authorization, and new offshore construction specifically carries full NEPA and Section 106 review exposure, the most extensive regulatory pathway among the modes considered in this

framework. Barge and ship transport instead fall under USACE and Coast Guard authorization, and, for ship transport specifically, IMO regulation, pathways that this study's regulatory sourcing indicates involve comparatively less procedural friction than new offshore pipeline construction, largely because they rely on existing vessel and port authorization regimes rather than a site-specific new-infrastructure review. This qualitative difference is not currently captured by the framework's two-flag regulatory risk mechanism, which evaluates protected-area crossing and new-OCS-authorization exposure identically regardless of mode, rather than distinguishing between the different regulatory bodies and review pathways each mode is actually subject to. A more complete treatment of regulatory risk would incorporate this mode-specific qualitative variation directly into the risk rating, rather than applying the same two flags uniformly across pipeline, barge, and ship pathways.

5.4 Study Limitations

Several limitations of this study should be considered when interpreting its results and applying its framework to other contexts.

First, tie-in feasibility to existing offshore oil and gas pipeline infrastructure could not be verified on a site-specific basis. The offshore pipeline GIS layer available for this study shows fragmented segments serving numerous unrelated platforms and fields, without accompanying data on connectivity, ownership, or available capacity, such that proximity to a mapped segment does not indicate an actual usable tie-in point (Section 3.8). The existing-pipeline pathway modeled in this framework should accordingly be read as an illustrative, lower-bound-cost scenario, informed by real precedent for oil and gas pipeline repurposing elsewhere, rather than as a confirmation that a specific tie-in is available for any particular emission source evaluated in this study.

Second, several cost parameters used in the framework, most notably the operating cost rates for barge ($0.055 per tonne-kilometer) and ship ($0.0043 per tonne-kilometer) transport, detailed in Appendix B, could not be verified to the same standard achieved for pipeline operating cost, where two independent published benchmark cases from the same foundational source (McCoy & Rubin, 2008) allowed direct calibration. Published barge operating cost figures span a wide range depending on commodity and market context, and the cleanest available ship operating cost benchmark is drawn from a non-United States context that does not reflect the Jones Act cost structure applied throughout this framework. Where a directly comparable published source was not available, parameters were derived through analogical

cross-reference to already-verified figures representing the same physical state of CO_2, scaled for throughput using a standard process-engineering cost-scaling relationship, rather than left as unverified in their original form.

Third, transport distances in this framework are calculated as straight-line, geodesic distances between coordinate points rather than as constructed route lengths. This is an appropriate simplification for a planning-level techno-economic framework, but it will understate actual route length to some degree, and a more detailed engineering study of a specific route would need to account for terrain, property boundaries, and existing infrastructure corridors.

Fourth, the framework's primary hybrid pathway mechanism models transfer hubs for a single emission source connecting to a primary transport mode. A multi-emitter extension, in which the capital cost of a shared hub and the primary mode's own capital cost are each allocated across the combined volumes of several participating emitters, was developed as a supplementary analysis (Section 4.8) rather than fully integrated into the primary decision-support tool. This supplementary analysis points to a substantial cost benefit from aggregation, though one that, in the specific cases tested, does not close the gap with pipeline, discussed further in Section 5.5. It has not been tested across the full range of scenarios evaluated elsewhere in this thesis, and should be read as an initial demonstration of the concept rather than a fully validated extension of the framework.

Fifth, this study's scenario set, while designed to span a meaningful range of distance and volume conditions across three industrial clusters, is not exhaustive of the emission sources identified in the underlying inventory. The representative facilities selected for each scenario were chosen based on reported annual emissions, and results for other facilities within the same clusters and categories may differ from the specific figures reported in Chapter 4, even if the general pattern of mode competitiveness is expected to hold.

Sixth, this framework quantifies regulatory and permitting risk but does not incorporate operational safety risk at transfer points as a cost-affecting factor. Preliminary risk assessment work conducted as part of this research for the GoMCarb project characterizes the hazard profile of CO_2 release during truck and barge transfer operations, including credible failure modes and dispersion behavior informed by real incident records such as the 2020 Satartia, Mississippi pipeline rupture (Section 2.4.7). That assessment indicates transfer operations carry a distinct risk profile, generally one of high local

severity with limited geographic extent, that is not currently reflected in this framework's cost or ranking outputs. Incorporating operational safety considerations into the decision-support framework, for example as an additional risk-weighted contingency alongside the existing regulatory risk mechanism, is identified as a direction for future research in Section 5.5.

Seventh, this thesis's original proposal included stakeholder interviews with engineering consultants, permitting authorities, and port and shipping experts as a planned methodology component, and early consultations of this kind were conducted during the course of this research and helped confirm the framework's premise that pipeline, barge, ship, and hybrid configurations should be evaluated as context-dependent options rather than fixed alternatives. These consultations were not, however, carried through into a structured set of interview findings integrated alongside the quantitative results in Chapter 4, and the perspectives they offered are accordingly reflected only in the framework's overall design rather than analyzed as a distinct line of evidence in this thesis.

Eighth, the marine capital cost scaling introduced in Section 3.4 is calibrated using vessel-capacity cost data from Vakili et al. (2025), applying the elasticity of cost with respect to vessel capacity as a proxy for the elasticity of cost with respect to annual volume. Vakili et al.'s (2025) own comparison holds annual throughput fixed, approximately 5.9 million tonnes per year in their Solent, United Kingdom case study, while varying vessel size to serve that fixed volume; this framework instead uses their reported cost-capacity relationship to infer how cost changes as annual volume itself varies, implicitly assuming that a larger annual volume is served by a proportionally larger vessel rather than more frequent voyages of a similarly sized one. These are related but not identical assumptions, since Vakili et al. (2025) do not directly test how cost responds to a change in annual volume at fixed vessel size. This substitution is a reasonable approximation given available data. However, a more complete treatment would model fleet composition and voyage frequency directly, rather than treating annual volume as a direct stand-in for vessel size.

Ninth, ship capital cost parameters in this framework are calibrated primarily against ZEP (2011), a detailed European CCS consortium report with resolved distance-dependent capital and operating cost breakdowns. An independent, more recent source, Vakili et al. (2025), reports ship cost data implying a similar order of magnitude but not the same value, and this framework has not fully reconciled the two. Both sources describe scenarios of a broadly comparable annual scale to this framework's own reference

volume, Vakili et al.'s (2025) Solent case at approximately 5.9 million tonnes per year and ZEP's (2011) cases at 2.5 to 20 million tonnes per year, so the difference between the two sources is not simply a matter of scale; ZEP (2011) was adopted as the primary calibration because it reports capital cost broken out explicitly by distance, which this framework's cost structure requires, while Vakili et al. (2025) report cost as a function of vessel size rather than distance directly. This tension between two credible sources is disclosed rather than resolved by selecting whichever figure is more convenient, and represents a genuine area of uncertainty in this framework's marine cost parameters.

Tenth, the Jones Act crew-cost premium applied to Barge – Large ATB (Coastal) in this framework is derived from the ship premium by adjusting for relative crew size, rather than taken from a directly reported barge-specific cost figure. Coastwise transport by an ocean-going, articulated tug-barge is subject to the same Jones Act requirements as a self-propelled ship. However, the source for the ship premium in this framework, U.S. Government Accountability Office (2018), does not report a barge-specific crew-cost differential. Industry sources report that an articulated tug-barge typically operates with a crew of eight to twelve, compared to as many as twenty-five for a comparable coastal tanker (Cowan, 2013); applying the midpoint of this range, ten, as a fraction of twenty-five to the smallest ship premium yields a barge-specific premium of approximately $2.67 per tonne, used throughout this framework. This crew-ratio approach assumes that the Jones Act crew-cost premium scales proportionally with crew size, a reasonable first approximation given that crew wages are the primary driver of the premium. However, it is not a substitute for a directly reported barge-specific cost figure, which was not identified for this thesis.

Eleventh, the tug-assisted and push-tow barge modes used as feeder connections in this framework are not assigned a Jones Act crew-cost premium, unlike the ATB and ship modes. This reflects a documented difference in fleet scarcity between the inland and coastal segments of the Jones Act fleet, and the presence of intermodal competition on inland routes that is largely absent on coastal and oceangoing routes, discussed in Section 3.5. This is a reasoned simplification rather than a precisely quantified figure: no directly reported crew-cost premium specific to inland tug-and-barge operations was identified for this thesis, and it remains possible that a small, currently unquantified premium exists for this category as well.

Twelfth, the Gulf Coast extension presented in Section 4.10 uses straight-line distances without route-specific landfall points, unlike the QGIS-derived corridor distances used for the primary Houston,

Beaumont, and Corpus Christi scenarios in Chapter 4, and does not apply the protected-area or federal-permitting screening described in Section 3.7. This is consistent with presenting the extension as a first-pass geographic robustness check rather than an engineering-grade analysis. The magnitude of the cost differences found there, generally an order of magnitude or more, is large enough that this simplification is unlikely to change the qualitative conclusion. However, a more detailed treatment would require the same route-specific and regulatory analysis applied to the primary scenarios.

Thirteenth, the duration-amortization treatment for barge and ship capital cost, discussed in Section 3.5, requires an assumed project life underlying each mode's reported cost figure: forty years for ship, taken directly from ZEP's (2011) own stated methodology, and twenty-five years for barge, inferred from standard maritime life-cycle-cost convention rather than confirmed directly from Vakili et al. (2025), whose own assumed project life was not accessible in the material available for this thesis. This assumption materially affects the duration-sensitivity results in Section 4.5 and the sensitivity analysis in Section 4.9, and a barge-specific reference project life confirmed directly from primary source data, rather than inferred from convention, would be a natural refinement.

5.5 Recommendations for Future Research

Building on the limitations identified above, several directions for future research would extend and strengthen the framework developed in this thesis.

The parameter sensitivity analysis in Section 4.9 identifies a specific, concrete priority for future work, rather than a general call for more data. Of the cost parameters evaluated in this framework, the regional variability of pipeline construction cost, not any marine-side parameter, has by far the largest effect on where the pipeline-ship crossover distance actually falls, producing swings of roughly 1,120 to 2,040 kilometers depending on annual volume, and remaining the most influential parameter at every scale tested, though the margin over the next most influential parameter narrows at higher volumes. A future front-end engineering design study aiming to resolve the pipeline-versus-ship question for a specific Gulf Coast corridor should accordingly prioritize obtaining a corridor-specific pipeline construction cost estimate, from a pipeline operator or engineering contractor, over further refining marine cost parameters: this framework’s own uncertainty in that comparison is dominated by the pipeline side, not the marine side, despite marine parameters receiving considerably more calibration attention in this thesis. This is offered as a specific, testable priority rather than a general call for more precise data, consistent with the

goal of identifying not just that uncertainty exists, but which particular number would most change the answer if resolved.

A multi-emitter shared-hub cost allocation model was developed and tested as a supplementary analysis in Section 4.8, applied to a real cluster of three facilities near the Sabine-Neches Waterway. This analysis allows both the transfer hub's cost and the primary mode's own cost to scale with the combined volume of multiple participating emitters, rather than treating the marine leg as a flat per-tonne rate insensitive to combined volume. The result is a substantial reduction in each facility's overall total cost, approximately 16 percent, though this does not change the identity of the least-cost mode for the cluster tested. Applying this model across the full scenario set evaluated in Chapter 4, rather than the single illustrative cluster tested here, remains a natural extension, and would allow the aggregation benefit to be characterized more generally across the range of emission source distributions present in the Gulf Coast.

Site-specific verification of existing pipeline tie-in feasibility, ideally in collaboration with pipeline operators or using proprietary connectivity data not available for this study, would allow the existing-pipeline pathway to be evaluated with greater confidence for a specific proposed project, rather than presented as an illustrative scenario.

The Northern Lights comparison discussed earlier in this chapter raised the question of whether pipeline's advantage is specific to the Texas corridor evaluated in Chapter 4 or generalizes further along the Gulf Coast. Section 4.10 tested this directly, using real facilities and real storage targets in Louisiana, Alabama, and Florida, and found that pipeline's advantage holds broadly, including at a combined aggregated volume of nearly 12 million tonnes per year, and that the one case where marine transport is actually used, a proposed barge system moving CO_2 from Florida, is explained by the complete absence of a pipeline option rather than by cost. A genuinely untested extension of this same question is a multi-stop marine collection route, a single vessel calling at several ports in sequence along the coast to aggregate CO_2 before delivering a combined cargo to storage, rather than the point-to-point and hub-and-spoke comparisons evaluated in this thesis. Modeling this properly would require route-specific distance data between candidate collection points and a cost structure that accounts for multiple port calls and the added transit time of a multi-stop voyage, neither of which this thesis's cost structure currently represents, and is identified here as a specific, well-defined extension rather than attempted in this thesis.

Further refinement of barge and ship operating cost parameters would strengthen the precision of the cost comparisons presented in this thesis, particularly for scenarios in which marine transport is close to cost-competitive with pipeline. This could be pursued through direct engagement with vessel operators such as Kirby Corporation for barge economics, or maritime engineering consultancies for Jones Act-compliant ship design.

Incorporating operational safety risk into the framework's cost or ranking mechanism represents a further extension. Preliminary GoMCarb risk assessment work conducted as part of this research qualitatively characterizes the hazard profile of CO_2 transfer operations, identifying credible failure modes and a risk profile of high local severity with limited geographic extent (Section 2.4.7). Translating this characterization into a quantitative, transfer-point-specific risk contingency, analogous to the regulatory risk mechanism developed in Section 3.7, would allow operational safety considerations to influence mode selection directly, rather than remaining a qualitative consideration external to the framework's cost outputs.

Finally, extending the scenario set beyond the representative facilities evaluated in this study, potentially to a comprehensive evaluation of every facility identified in the underlying emissions inventory, would allow the framework's findings to be generalized with greater confidence across the full range of Gulf Coast emission sources rather than the representative subset evaluated here.

5.6 Summary of Contributions and Relevance to CCS Deployment

This thesis makes six contributions to the study of CO_2 transport planning, summarized in relation to the results presented in Chapter 4.

The multimodal decision-support framework developed in Chapters 3 and 4 demonstrates, through application to a real Gulf Coast case study, that transport mode competitiveness is governed by the interaction of distance, volume, and duration rather than by fixed criteria. This behavior can be captured in a transparent, independently verifiable techno-economic model without resorting to a weighted scoring approach. The framework's treatment of regulatory risk as a cost-affecting contingency, rather than a weighted criterion or a cosmetic label, allows regulatory considerations to influence which transport mode is identified as least-cost, addressing a gap in existing pipeline-network optimization tools identified in Section 2.8.3. The spatial and GIS-based components of the framework demonstrate a practical, defensible

method for incorporating shoreline crossing and protected-area constraints into transport mode evaluation using data and tools accessible to a planning-level study, without requiring proprietary routing software. The characterization of transfer hub ownership, operation, and permitting models, developed in response to RQ5, identifies real precedent for the aggregation-hub architecture this framework assumes, including a currently operating shared-terminal arrangement on the Houston Ship Channel. It also identifies the absence of a comparable multi-party precedent specific to CO_2 transport as an open question for the CCS sector as it scales. The decision-support tool implemented alongside this framework provides a transparent, reusable platform that can be applied to additional Gulf Coast scenarios, or adapted to other coastal CCS deployment contexts, beyond the specific case study presented in this thesis; the geographic robustness check in Section 4.10, applying the same framework to real facilities and storage targets in Louisiana, Alabama, and Florida, demonstrates this reusability directly rather than only in principle.

Collectively, these contributions support the deployment of CCS infrastructure in the Gulf Coast by providing a structured basis for evaluating transport strategy that accounts for the technical, spatial, economic, and regulatory factors relevant to a real project, rather than treating transport mode selection as a simple point-to-point cost comparison. As CCS deployment in the Gulf Coast and similar regions continues to scale, the questions this thesis addresses, particularly around aggregation, shared infrastructure, and the regulatory treatment of multimodal transport pathways, are likely to become more, rather than less, consequential to how CO_2 transport systems are ultimately designed and financed.

5.7 Conclusion

This thesis set out to answer five research questions concerning CO_2 transport strategy in the Texas Gulf Coast, and the results in Chapter 4 provide a direct answer to each.

RQ1 asked under what conditions pipeline, marine, or hybrid CO_2 transport systems are most cost-effective and feasible. The case study shows that requalified existing pipeline is least-cost across every Gulf Coast scenario evaluated in this thesis, reflecting the short distances and moderate volumes characteristic of the region, and this holds even after correcting for the same volume-dependent economies of scale this framework applies to pipeline, barge, and ship alike. A geographic robustness check extending the same framework to real facilities in Louisiana, Alabama, and Florida confirms this finding holds beyond the specific Texas corridor evaluated in the primary scenarios, and identifies the specific conditions under which the answer does change: at very large aggregated scale, marine transport

approaches, though does not overtake, pipeline's cost; and where no pipeline option exists at all, as in the real Florida-to-Louisiana barge project examined in Chapter 4, marine transport is used regardless of relative cost. No single mode is universal in principle, but within the distances, volumes, and durations evaluated in this thesis, pipeline's advantage is decisive rather than conditional.

RQ2 asked how spatial constraints, including shoreline crossings and infrastructure availability, affect transport system design and cost. The GIS-based methodology developed in Chapter 3 shows that protected-area crossings and the availability of tie-in infrastructure are not incidental details but active constraints on route feasibility and cost, and that straight-line distance alone, without accounting for these constraints, would understate the real complexity of routing a Gulf Coast CO_2 transport system.

RQ3 asked how regulatory and permitting considerations influence feasibility and timing. The regulatory risk mechanism developed in this thesis demonstrates that regulatory exposure functions as a cost-relevant constraint rather than a peripheral consideration, capable of shifting which mode ranks as least-cost, and that assumptions about existing infrastructure availability, such as whether a route can rely on requalified pipeline versus new construction, carry direct financial consequences shown in Chapter 4.

RQ4 asked how a decision-support framework could be structured to enable consistent, transparent comparison of multimodal strategies. The framework presented in Chapter 3, built as an inspectable, independently verified Excel tool rather than an opaque model, demonstrates that this kind of comparison does not require proprietary optimization software, and that a threshold-based structure can represent mode competitiveness more faithfully than a weighted-criteria scoring approach.

RQ5 asked how transfer hubs might be owned, operated, and permitted, and what precedent exists for shared infrastructure of this kind. The precedents examined in Chapter 3, particularly the Oiltanking terminal already serving multiple unrelated Houston Ship Channel refineries, show that the shared-hub architecture this thesis assumes is not a novel proposal but an extension of a business model already operating at scale in the same region, and the supplementary multi-emitter analysis in Chapter 4 demonstrates that this sharing produces a substantial cost benefit for the marine transport leg specifically, though one that does not overturn pipeline's overall cost advantage in the scenarios evaluated.

Taken together, these answers support the thesis's central argument: CO_2 transport mode selection in the Gulf Coast is not a fixed outcome determined by geography alone, but a condition-dependent

decision shaped jointly by distance, volume, duration, regulatory exposure, and the availability of shared infrastructure. A decision-support framework that makes these interactions explicit, rather than resolving them into a single weighted score, gives planners a more honest and more useful basis for that decision than either a pipeline-only optimization tool or a qualitative comparison of transport modes in isolation.

Appendices

APPENDIX A: FULL SCENARIO RESULTS (ALL 22 SCENARIOS)

This appendix presents complete results for all 22 scenarios evaluated in this study, corresponding to the summarized results presented in Chapter 4. Total distance for each scenario combines onshore and offshore segments, calculated separately using the Haversine formula (Section 3.8), summed for pipeline modes, or the relevant marine leg plus feeder distance for barge and ship modes, consistent with the door-to-door cost treatment described in Section 3.4. Unlike the summary tables in Chapter 4, which report only the least-cost mode, the tables below report the computed cost for all three primary modes, pipeline, barge, and ship, for every scenario, so that the magnitude of pipeline's cost advantage can be assessed directly rather than taken on faith.

Scenario	Total (km)	Volume (t/yr)	Prot. Area	Least-Cost Mode	Pipeline ($/t)	Barge ($/t)	Ship ($/t)	Reg. Risk
Houston, 400,000+ t/yr, near	109.1	12,621,516	N	Pipeline, Offshore (Existing)	3.03	68.22	39.52	Medium
Houston, ~100,000 t/yr, near	117.1	107,905	N	Pipeline, Offshore (Existing)	27.82	355.38	87.56	Medium
Beaumont, 400,000+ t/yr, near	120.3	5,948,714	Y	Pipeline, Offshore (Existing)	3.68	88.35	41.50	Medium
Beaumont, ~100,000 t/yr, near	127.2	100,291	Y	Pipeline, Offshore (Existing)	31.47	356.64	88.01	Medium
Corpus Christi, 400,000+ t/yr, near	128.3	5,234,689	N	Pipeline, Offshore (Existing)	3.94	92.77	41.34	Medium

Scenario	Total (km)	Volume (t/yr)	Prot. Area	Least-Cost Mode	Pipeline ($/t)	Barge ($/t)	Ship ($/t)	Reg. Risk
Corpus Christi, 400,000+ t/yr, far	217.4	673,133	N	Pipeline, Offshore (Existing)	11.41	249.16	71.47	Medium
Corpus Christi, ~100,000 t/yr, near	196.6	109,099	N	Pipeline, Offshore (Existing)	39.93	359.00	86.61	Medium
Corpus Christi, ~100,000 t/yr, far	238.5	103,482	Y	Pipeline, Offshore (Existing)	48.82	366.69	96.38	Medium
Controlled — Short (Olin Blue Cube)	69.8	1,402,548	N	Pipeline, Offshore (Existing)	4.14	159.94	47.30	Medium
Controlled — Medium (Galveston Bay)	102.6	6,583,677	N	Pipeline, Offshore (Existing)	3.31	82.60	38.08	Medium
Controlled — Long (Motiva, Port Arthur)	186.6	4,962,936	Y	Pipeline, Offshore (Existing)	5.04	97.57	41.21	Medium

Table A1. Complete scenario results, Corsair Trough core storage area.

Scenario	Total (km)	Volume (t/yr)	Prot. Area	Least-Cost Mode	Pipeline ($/t)	Barge ($/t)	Ship ($/t)	Reg. Risk
Houston, 400,000+ t/yr, near	65.8	12,621,516	N	Pipeline, Offshore (Existing)	2.45	65.72	39.13	Medium

Scenario	Total (km)	Volume (t/yr)	Prot. Area	Least-Cost Mode	Pipeline ($/t)	Barge ($/t)	Ship ($/t)	Reg. Risk
Houston, ~100,000 t/yr, near	69.1	107,905	Y	Pipeline, Offshore (Existing)	20.26	352.58	87.04	Medium
Beaumont, 400,000+ t/yr, near	56.2	5,948,714	Y	Pipeline, Offshore (Existing)	2.60	84.73	41.03	Medium
Beaumont, ~100,000 t/yr, near	61.4	100,291	Y	Pipeline, Offshore (Existing)	20.35	351.91	85.60	Medium
Corpus Christi, 400,000+ t/yr, near	75.7	5,234,689	Y	Pipeline, Offshore (Existing)	3.00	90.08	41.50	Medium
Corpus Christi, 400,000+ t/yr, far	163.0	673,133	N	Pipeline, Offshore (Existing)	9.25	246.29	71.46	Medium
Corpus Christi, ~100,000 t/yr, near	144.3	109,099	N	Pipeline, Offshore (Existing)	31.78	356.02	86.18	Medium
Corpus Christi, ~100,000 t/yr, far	192.0	103,482	N	Pipeline, Offshore (Existing)	41.20	364.79	97.42	Medium
Controlled — Short (Olin Blue Cube)	55.1	1,402,548	Y	Pipeline, Offshore (Existing)	3.71	159.14	47.27	Medium
Controlled — Medium (Galveston Bay)	104.5	6,583,677	N	Pipeline, Offshore (Existing)	3.34	83.15	38.92	Medium

Scenario	Total (km)	Volume (t/yr)	Prot. Area	Least-Cost Mode	Pipeline ($/t)	Barge ($/t)	Ship ($/t)	Reg. Risk
Controlled — Long (Motiva, Port Arthur)	200.8	4,962,936	N	Pipeline, Offshore (Existing)	5.30	98.74	41.99	Medium

Table A2. Complete scenario results, surrounding (extended) storage area

All scenarios assume a 20-year project duration. Every scenario returns a Medium regulatory risk rating, discussed in Section 4.7 as reflecting this case study's conservative assumption that new federal offshore authorization is required throughout, rather than a limitation of the risk mechanism itself, which is independently verified to produce Low and High ratings under different input conditions (Table 4.6).

APPENDIX B: COMPLETE TRANSPORT MODE PARAMETER LIBRARY

This appendix presents the complete set of verified capital and operating cost parameters underlying the framework, corresponding to the summarized figures presented in Chapter 3. Sourcing and verification methodology for each parameter is described in Section 3.5; regulatory sourcing is described in Section 3.7.

Each transport mode has exactly one operative capital cost representation, reflecting its cost basis (Section 3.4): pipeline capital cost scales with distance and is captured by the CAPEX-per-kilometer figure in Table B2, while barge, ship, truck, and rail capital cost is a flat aggregate figure per tonne, captured by the CAPEX Mid figure in Table B1. A dash in either table indicates that the corresponding representation is not applicable to that mode's cost structure, not a missing value; the Parameter Library retains legacy flat-rate figures for the three pipeline modes predating the distance-based correction described in Section 3.4, but these are not read by the cost formula and are omitted here to avoid presenting an unused figure as though it were operative.

Mode	Mode Type	CAPEX Low ($/t)	CAPEX High ($/t)	CAPEX Mid ($/t)	OPEX Low ($/t-km)	OPEX High ($/t-km)	OPEX Mid ($/t-km)	Cost Basis
Pipeline – Onshore (New)	Primary	—	—	—	0.004	0.008	0.0058	Distance-based, volume-scaled
Pipeline – Offshore (Existing)	Primary	—	—	—	0.004	0.008	0.0058	Distance-based, volume-scaled
Pipeline – Offshore (New)	Primary	—	—	—	0.004	0.008	0.0058	Distance-based, volume-scaled
Barge – Small (Tug-assisted)	Feeder	25	50	37.5	0.03	0.08	0.055	Flat $/t, volume-scaled
Barge – Large (Push Tow)	Feeder	25	60	42.5	0.03	0.08	0.055	Flat $/t, volume-scaled
Barge – Large ATB (Coastal)	Primary	30	60	45	0.03	0.08	0.055	Flat $/t, volume-scaled
Ship – Small (Cryogenic, Short-haul)	Primary	8.44	14.06	11.25	0.0029	0.0057	0.0043	Flat $/t, volume-scaled

Mode	Mode Type	CAPEX Low ($/t)	CAPEX High ($/t)	CAPEX Mid ($/t)	OPEX Low ($/t-km)	OPEX High ($/t-km)	OPEX Mid ($/t-km)	Cost Basis
Ship – Large (Cryogenic, Long-haul)	Primary	6.98	11.62	9.30	0.0029	0.0057	0.0043	Flat $/t, volume-scaled
Ship – Small (Pressurized, Short-haul)	Primary	3.75	6.25	5.00	0.0029	0.0057	0.0043	Flat $/t, volume-scaled
Truck – Short-haul	Feeder	10	25	17.5	0.10	0.12	0.111	Flat $/t
Truck – Cryogenic	Feeder	10	30	20	0.10	0.12	0.111	Flat $/t
Rail – Pressurized	Feeder	20	35	27.5	0.045	0.06	0.05	Flat $/t

Table B1. Capital and operating cost parameters by transport mode.

Mode	CAPEX per km ($M/km)	Compression/Liquefaction CAPEX ($M, total)	Transfer Infrastructure CAPEX ($M, total)	OPEX-Compression ($/t)
Pipeline – Onshore (New)	3.0	8.0	8.5	1.50
Pipeline – Offshore (Existing)	1.0	6.0	11.0	1.50

Mode	CAPEX per km ($M/km)	Compression/Liquefaction CAPEX ($M, total)	Transfer Infrastructure CAPEX ($M, total)	OPEX-Compression ($/t)
Pipeline – Offshore (New)	5.4	10.0	14.0	1.50
Barge – Small (Tug-assisted)	—	24.0	5.5	1.25
Barge – Large (Push Tow)	—	24.0	5.5	1.25
Barge – Large ATB (Coastal)	—	24.0	5.5	1.25
Ship – Small (Cryogenic, Short-haul)	—	75.0	8.5	3.00
Ship – Large (Cryogenic, Long-haul)	—	82.5	11.0	2.25
Ship – Small (Pressurized, Short-haul)	—	24.0	5.5	1.25
Truck – Short-haul	—	0.94	0.12	1.50
Truck – Cryogenic	—	11.42	1.41	2.63

Mode	CAPEX per km ($M/km)	Compression/Liquefaction CAPEX ($M, total)	Transfer Infrastructure CAPEX ($M, total)	OPEX-Compression ($/t)
Rail – Pressurized	—	1.89	0.23	1.50

Table B2. Pipeline capital cost per kilometer and transfer hub/compression parameters by mode.

Mode	Regulatory Framework
Pipeline – Onshore (New)	PHMSA 49 CFR 195; Texas DOT/RRC and USACE right-of-way authorization
Pipeline – Offshore (Existing)	BOEM/BSEE authorization, PHMSA safety regulation; requires formal re-qualification under pipeline design codes given the change in transported product
Pipeline – Offshore (New)	BOEM/BSEE authorization, PHMSA safety regulation; full NEPA and Section 106 review required
Barge (all variants)	USACE and U.S. Coast Guard authorization; port access; Jones Act applies but is not a barrier given the active domestic ATB and barge fleet
Ship (all variants)	U.S. Coast Guard and IMO regulation; port access; Jones Act construction and crewing premiums applied (Section 3.5)
Truck (all variants)	DOT/FMCSA 49 CFR 171–180 (hazardous materials); state and local permits; a routing risk rather than a siting risk
Rail – Pressurized	Federal Railroad Administration; PHMSA/DOT hazardous materials regulation (49 CFR 171–180); existing right-of-way and trackage rights

Table B3. Regulatory sourcing by transport mode.

Glossary

ACT — Accelerating CCS Technologies (co-fund program, Horizon 2020)

AHP — Analytic Hierarchy Process

ATB — Articulated Tug-Barge

BEIS — (UK) Department for Business, Energy & Industrial Strategy

BOEM — Bureau of Ocean Energy Management

BSEE — Bureau of Safety and Environmental Enforcement

CAPEX — Capital Expenditure

CCS — Carbon Capture and Storage

CCSA — Carbon Capture and Storage Association

CCUS — Carbon Capture, Utilization, and Storage

CO_2 — Carbon Dioxide

DNV — Det Norske Veritas

DOT — (U.S.) Department of Transportation

EOR — Enhanced Oil Recovery

EPA — (U.S.) Environmental Protection Agency

FEED — Front-End Engineering Design

FMCSA — Federal Motor Carrier Safety Administration

GCCC — Gulf Coast Carbon Center

GHG — Greenhouse Gas

GIS — Geographic Information System

GIWW — Gulf Intracoastal Waterway

GoMCarb — Gulf of Mexico Partnership for Offshore Carbon Storage

IEA — International Energy Agency

IEAGHG — IEA Greenhouse Gas R&D Programme

IMO — International Maritime Organization

IPCC — Intergovernmental Panel on Climate Change

JV — Joint Venture

LNG — Liquefied Natural Gas

NEPA — National Environmental Policy Act

NETL — National Energy Technology Laboratory

OCAP — Organic Carbon dioxide for Assimilation of Plants (pipeline)

OCS — Outer Continental Shelf

OPEX — Operating Expenditure

PHMSA — Pipeline and Hazardous Materials Safety Administration

RQ — Research Question

ROW — Right-of-Way

RRC — Railroad Commission of Texas

TOPSIS — Technique for Order of Preference by Similarity to Ideal Solution

USACE — U.S. Army Corps of Engineers

ZEP — Zero Emissions Platform

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