Angeles Link – Phase 1
Quarterly Report (Q3 2024)

For the period of July 1, 2024 through September 30, 2024

Appendix 1E - Draft Reports:
Permitting Analysis
Alternatives Study
Cost Effectiveness Study

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ANGELES LINK PHASE 1

High-Level Feasibility Assessment and Permitting Analysis

DRAFT REPORT– JULY 2024

SoCalGas commissioned this analysis from Rincon Consultants. The analysis was conducted, and this report was prepared, collaboratively.

July 2024

Angeles Link | High-Level Feasibility Assessment and Permitting Analysis

Executive Summary

Southern California Gas Company (SoCalGas) is proposing to develop a clean renewable hydrogen[1] pipeline system to facilitate transportation of clean renewable hydrogen from multiple regional third-party production sources and storage sites to various delivery points and end users in Central and Southern California, including in the Los Angeles Basin. SoCalGas retained Rincon Consultants, Inc. (Rincon) to prepare this High-Level Feasibility Assessment and Permitting Analysis (Permit Analysis) in alignment with the California Public Utilities Commission's (CPUC) Phase 1 Decision authorizing activities associated with SoCalGas's proposed Angeles Link Project (Project) to be recorded to a memorandum account. SoCalGas is identifying and comparing possible routes and configurations for the Project in accordance with the Decision Ordering Paragraph 6(i) and 6(n). This Permit Analysis is based on SoCalGas's Preliminary Routing/Configuration Analysis (Routing Study), and with that study will help inform further refinements to Angeles Link's preferred routes in a future phase. The Routing Study Analysis resulted in four preliminary preferred route configurations of the highest potential that may fulfill Angeles Link's purpose, and identified a fifth potential scenario that could minimize impacts to Disadvantaged Communities (DACs) in response to stakeholder feedback. [2]

The objective of this Permit Analysis is to evaluate at a desktop level potential pipeline routes to determine the permits and authorizations anticipated to be required for construction of Angeles Link. The analysis included a high-level review of federal, state, and local jurisdictional lands[3] and waters, military bases, existing transportation corridors, highway and railroad crossings, state and federally protected plants and wildlife, and land owned by special districts.

[1] In the California Public Utilities Commission Angeles Link Phase 1 Decision (D).22-12-055 (Decision), clean renewable hydrogen refers to hydrogen that does not exceed 4 kilograms of carbon dioxide equivalent (CO2e) produced on a lifecycle basis per kilogram of hydrogen produced and does not use fossil fuels in the hydrogen production process, where fossil fuels are defined as a mixture of hydrocarbons including coal, petroleum, or natural gas, occurring in and extracted from underground deposits.

[2] Route analysis has been conducted at a high level during the feasibility stage. Subsequent phases of route evaluation will consider more detailed alignment.

[3] Federal, state, and local jurisdictional lands include, but are not limited to, National Park Service, Bureau of Land Management, U.S. Forest Service, California Department of Parks and Recreation, California State Lands Commission, and county parks.

As described in SoCalGas's Routing Study, SoCalGas initially identified potential pipeline corridors based on certain criteria as described further in that study, including but not limited to route features, existing pipeline right-of-way, franchise rights, and designated federal energy corridors. The initial pipeline routing analysis identified approximately 1,300 miles of conceptual pipeline routes, which have been evaluated in this Permit Analysis.

Key Findings

The key findings are presented below and are discussed further within the attached study.

- Angeles Link will likely require a federal action[4] and therefore will likely be subject to the National Environmental Protection Act (NEPA).
  - Federal authorizations/permits may include approval(s) by the U.S. Department of Energy, Bureau of Land Management, Bureau of Reclamation, U.S. Army Corps of Engineers, U.S. Fish and Wildlife, Department of Defense and U.S. Forest Service.[5]
- The CPUC will serve as the California Environmental Quality Act (CEQA)[6] lead agency.
  - Other state authorizations/permits may require approval by the California Department of Transportation, Department of Water Resources, State Water Resources Control Board, California Department of Fish and Wildlife, State Lands Commission, and Department of Parks and Recreation.
- As a preferred route is identified and further refined, other authorizations by regional agencies for activities may be implicated.
- Permitting timelines may range from months to several years, based on current agency regulations and published timelines, and SoCalGas's/Rincon's experience working with the applicable agencies and pipeline infrastructure permitting.
- Permitting timelines may change if permit streamlining legislation is adopted that may impact permitting timelines for clean hydrogen projects.

Stakeholder Input

The input and feedback from stakeholders including the Planning Advisory Group (PAG) and Community Based Organization Stakeholder Group (CBOSG) have been essential to the development of the Angeles Link Phase 1 studies. Some of the feedback that has been received related to this Permit Analysis is summarized below. All feedback received is

[4] Several federal agencies may have discretionary approval where Project infrastructure traverses their lands or where the Project may impact biological resources over which federal agencies have jurisdiction. In addition, a grant of federal funding for select segments of the Project from the U.S. Department of Energy would constitute a federal action subject to NEPA.

[5] Two segments included in the conceptual pipeline routes (Segment C in the Connection Zone and Segment B in the Collection Zone) have been identified to be included in the California ARCHES hydrogen hub. The White House has announced that California will receive up to $1.2 billion in funding from the Department of Energy for the state's hydrogen hub. https://archesh2.org/california-wins-up-to-1-2-billion-from-feds-for-hydrogen/.

[6] The project will require a discretionary action from the CPUC and potentially other state agencies triggering compliance with CEQA.

included, in its original form, in the quarterly reports submitted to the CPUC and published on SoCalGas's website.[7]

Preliminary Data and Findings[8]

Preliminary data and Findings were published on April 11, 2024, to the PAG/CBOSG Living Library, which is a dedicated Project virtual database available to PAG/CBOSG members.

- One comment letter received from Communities for a Better Environment (CBE) included the following feedback related to this Permit Analysis:
  - CBE stated that without identifying any potential routes in relation to permitting, it is impossible to discern from the array of potential permitting and regulatory requirements which permitting requirements, constraints, and timing considerations will be significant factors in limitation of the Project's development.

Summary of How Comment Was Addressed

- This Permit Analysis evaluates all 1,300 miles of conceptual pipeline routes initially identified for Angeles Link.
- The separate Routing Study identifies four preferred routes for Angeles Link (Route Configurations A, B, C, D). As requested by CBE, the Permit Analysis evaluates the potential permitting requirements and constraints applicable to those preferred routes because those preferred routes are included in the 1,300 miles of conceptual pipeline routes initially identified for Angeles Link. Additionally timing constraints associated with potential permits have been included in this study.
- The conceptual routes will be further refined based on continued engineering and design analysis in Phase 2, as well as stakeholder and/or agency feedback.

[7] https://www.socalgas.com/sustainability/hydrogen/angeles-link

[8] SoCalGas did not receive any comments on the High-Level Feasibility Study and Permitting Assessment scope of work and technical approach documents.

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Acronyms and Abbreviations

Alliance for Renewable Clean Hydrogen Energy Systems	ARCHES
Angeles Link Phase 1 Preliminary Routing/Configuration Analysis	Routing Study
Angeles Link Project	Project
Bureau of Land Management	BLM
Bureau of Land Reclamation	BOR
California Department of Fish and Wildlife	CDFW
California Department of Parks and Recreation	State Parks
California Department of Transportation	Caltrans
California Department of Water Resources	DWR
California Endangered Species Act	CESA
California Environmental Quality Act	CEQA
California Natural Diversity Database	CNDDB
California Public Utilities Commission	CPUC
California State Lands Commission	CSLC
Certificate of Public Convenience and Necessity	CPCN
Clean Water Act	CWA
Department of Defense	DoD
Endangered Species Act	ESA
Environmental Impact Statement	EIS
Environmental Impact Report	EIR
Federal Endangered Species Act	ESA
Habitat Conservation Plan	HCP
Incidental Take Permit	ITP
Interstate	I-
Kern County Valley Floor Habitat Conservation Plan	VFHCP
National Environmental Policy Act	NEPA
National Park Service	NPS
Nationwide Permit	NWP

Natural Community Conservation Plan	NCCP
High-Level Feasibility Assessment and Permitting Analysis	Permit Analysis
Permit to Construct	PTC
Regional Water Quality Control Board	RWQCB
Right-of-Way	ROW
Rincon Consultants, Inc.	Rincon
Southern California Gas Company	SoCalGas
Standard Form	SF-
State Route	SR-
United States Army Corps of Engineers	USACE
United States Air Force	USAF
United States Fish and Wildlife Service	USFWS
United States Forest Service	USFS
United States Marine Corps	USMC
Waters of the U.S.	WOTUS

Chapter 1 Introduction

A desktop analysis was prepared for this Angeles Link High-Level Feasibility Assessment & Permitting Analysis (Permit Analysis) for Southern California Gas Company (SoCalGas) in support of Angeles Link. This Permit Analysis is one feasibility study in a group of feasibility studies being conducted as part of Angeles Link Phase 1. Angeles Link would be a high-pressure, non-discriminatory pipeline system that is dedicated to public use to transport clean renewable hydrogen[9] from regional and third-party production and storage sites to end users in Central and Southern California, including the Los Angeles Basin (inclusive of the Ports of Los Angeles and Long Beach). The proposed pipeline system would traverse approximately 450 miles.

1.1 Scope of Analysis

Rincon was contracted by SoCalGas to assist in the preparation of a high-level environmental permit analysis for the potential pipeline routes under evaluation for Angeles Link.[10] A desktop analyses was conducted of potential segments within the conceptual pipeline routes to determine the permits and authorizations anticipated to be required for construction of the Project. This Permit Analysis includes a review of federal, state, and local jurisdictional lands[11] and waters, military bases, existing transportation corridors, highway and railroad crossings, state and federally protected plants and wildlife, and land owned/managed by special districts.

SoCalGas's Angeles Link Phase 1 Preliminary Routing/Configuration Analysis (Routing Study) identified approximately 1,300 miles of conceptual pipeline routes (Figure 1). At this stage in the Angeles Link feasibility analysis, the 1,300 miles of conceptual pipeline routes are directional in nature. The conceptual routes do not illustrate the specific routes where Angeles Link may be constructed, as specific routes and street-level alignments will be further studied and refined in future phases of Angeles Link. However, while still directional in nature, for purposes of evaluating the potential environmental impacts and permit approvals that may apply to Angeles Link, this Permit Analysis reviewed specific routes drawn on a map for the informational purposes of this study.

This Permit Analysis evaluates the entire 1,300 miles to provide information about the permitting considerations and timing constraints that could inform the selection of a proposed route. As described further in Section 1.3.2 Routing Study Preferred Routes, SoCalGas has identified four preferred routes in its Routing Study, incorporated herein by reference, that will be subject to further stakeholder input and evaluation. In addition, in

[9] Per the Decision (D.22-12-055), "clean renewable hydrogen" is defined as hydrogen produced with a carbon intensity equal to or less than four kilograms of carbon dioxide-equivalent produced on a lifecycle basis per kilogram and does not use any fossil fuel in its production process.

[10] The Permit Analysis evaluates potential pipeline routes, excluding compression because specific compression needs and/or locations have not been identified at this feasibility level of evaluation. These routes are based on available information as of May 9, 2024.

[11] Federal, state, and local jurisdictional lands include, but are not limited to, National Park Service, Bureau of Land Management, U.S. Forest Service, California Department of Parks and Recreation, California State Lands Commission, and county parks.

response to feedback received from the Angeles Link Planning Advisory Group (PAG) and (CBOSG) stakeholders, SoCalGas further reviewed the conceptual routes and identified a fifth potential scenario for the pipeline system that may minimize potential operational and construction impacts of Angeles Link in disadvantaged communities (DAC). The fifth scenario, along with the other identified preferred routes, will be further analyzed in future phases of Angeles Link.

1.2 Report Organization

This study provides a summary of federal, state, and special districts that may have permitting authority over Angeles Link. The study also provides information about regulated biological resources within or adjacent to potential pipeline segments identified in the Routing Study based on a literature review and desktop analysis. Key permitting considerations and a discussion of potential California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) lead agencies is also included.

1.3 Pipeline Zones, Segments and Preferred Route Configurations

The Routing Study identifies three zones within Central and Southern California that each reflect different aspects of Angeles Link's contemplated hydrogen delivery system—the Connection Zone, Collection Zone, and Central Zone, as further described below and shown in Figure 2, Figure 3, and Figure 4.[12]

The Connection Zone provides opportunities for connection to other hydrogen networks in-state and out-of-state. The Connection Zone includes potential pipeline segments generally located throughout Fresno, Kings, Kern, San Bernardino, Riverside, and Orange counties. The Connection Zone includes areas identified to access clean renewable hydrogen producers in the San Joaquin Valley via Interstate (I-) 5/State Route (SR-) 99, High Desert via I-15, Low Desert via I-10 and Southern Desert via I-40.

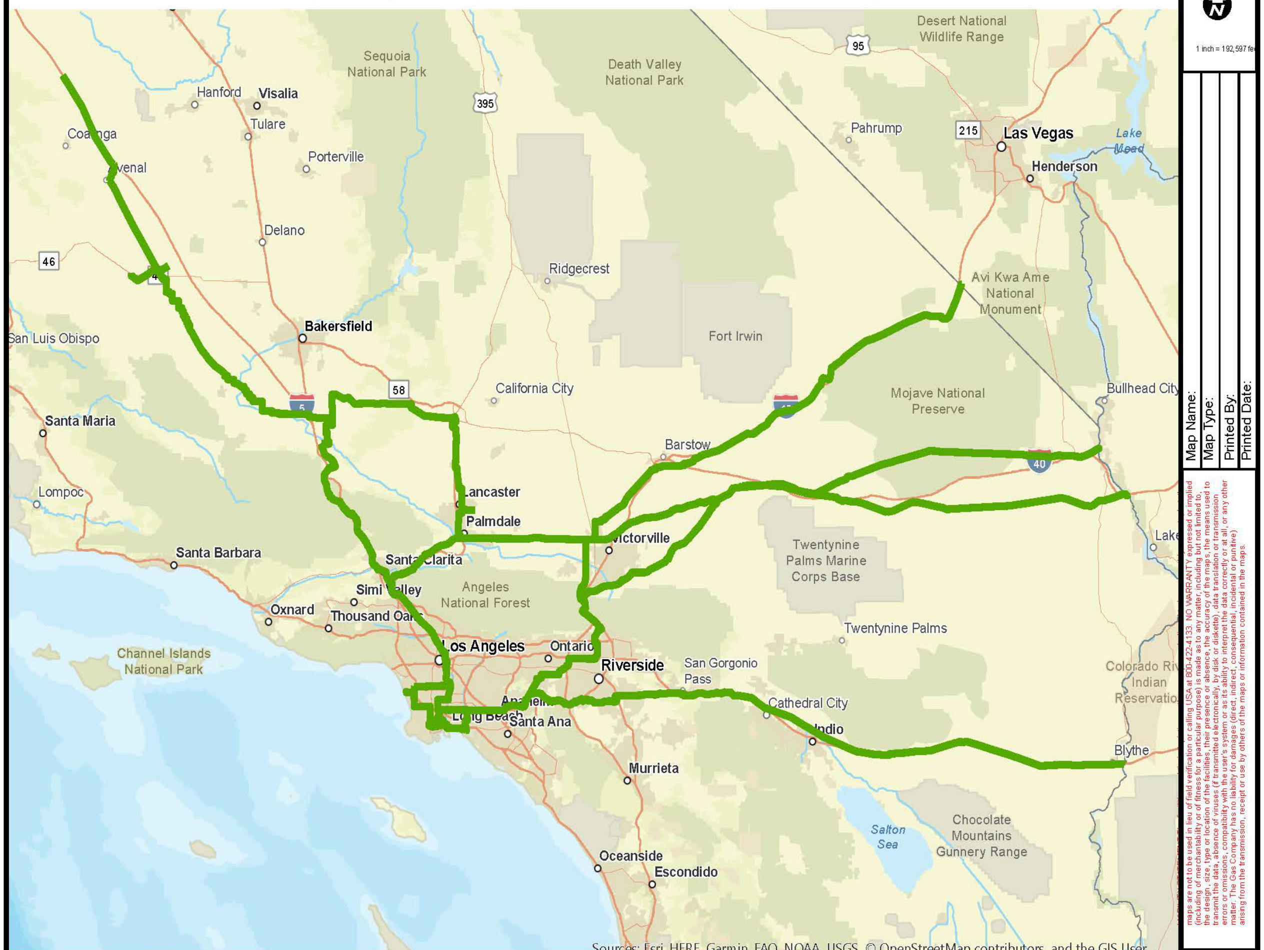
The Collection Zone provides additional opportunities to collect gas from hydrogen suppliers and supports distribution to offtake to end users in the zone. The Collection Zone includes potential pipeline segments in Mojave, California and follows a path through Kern, Ventura, Los Angeles, Orange, Riverside, and San Bernardino counties.

The Central Zone includes the area anticipated to be the highest area of potential offtake (in the Los Angeles Basin) given the concentration of demand from the hard-to-electrify sectors and the target demand anticipated for Angeles Link. The Central Zone includes potential pipeline segments located primarily within the southwestern portion of Los Angeles County. The zone is made up of potential pipeline routes extending out from the Collection Zone to the more industrial areas of the Los Angeles Basin, including the ports of Los Angeles and Long Beach.

[12] For more information on the identification of the segments within the potential pipeline corridors and the development of the Connection, Collection and Central Zones, see the separate Angeles Link Phase 1 feasibility analysis in the Routing Study.

Figure 1 Conceptual Pipeline Corridors Under Evaluation

Conceptual Pipeline Corridors Under Evaluation*



*These renderings show conceptual corridors (or initial concepts) for the Angeles Link project. Potential Angeles Link routes are still to be determined and analyzed for feasibility including hydraulics, engineering, etc. During Phase Two, corridors will be further evaluated to produce refined proposals.

Figure 2 Pipeline Segments within the Connection Zone Overview Map

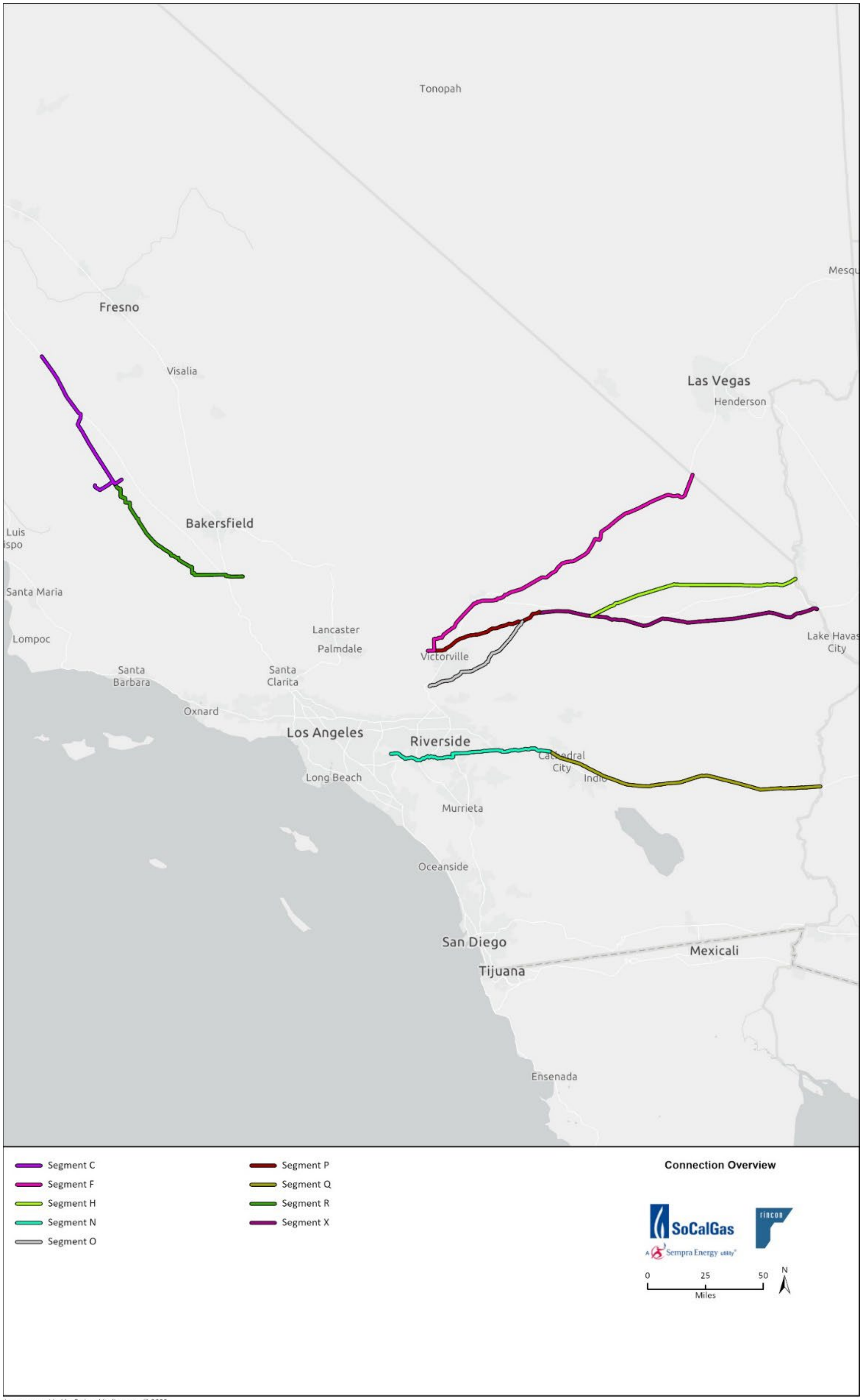


Figure 3 Pipeline Segments within the Collection Zone Overview Map

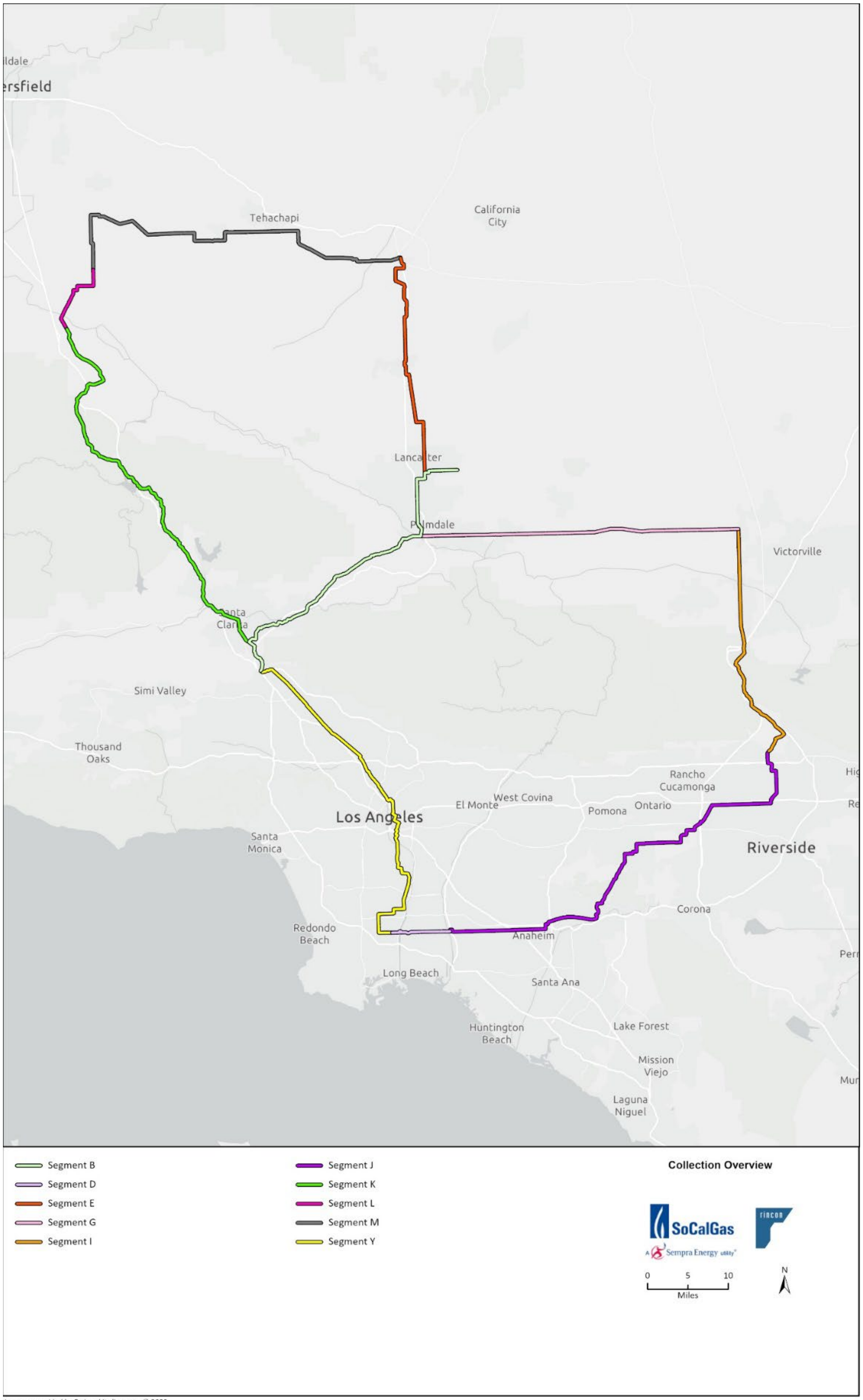
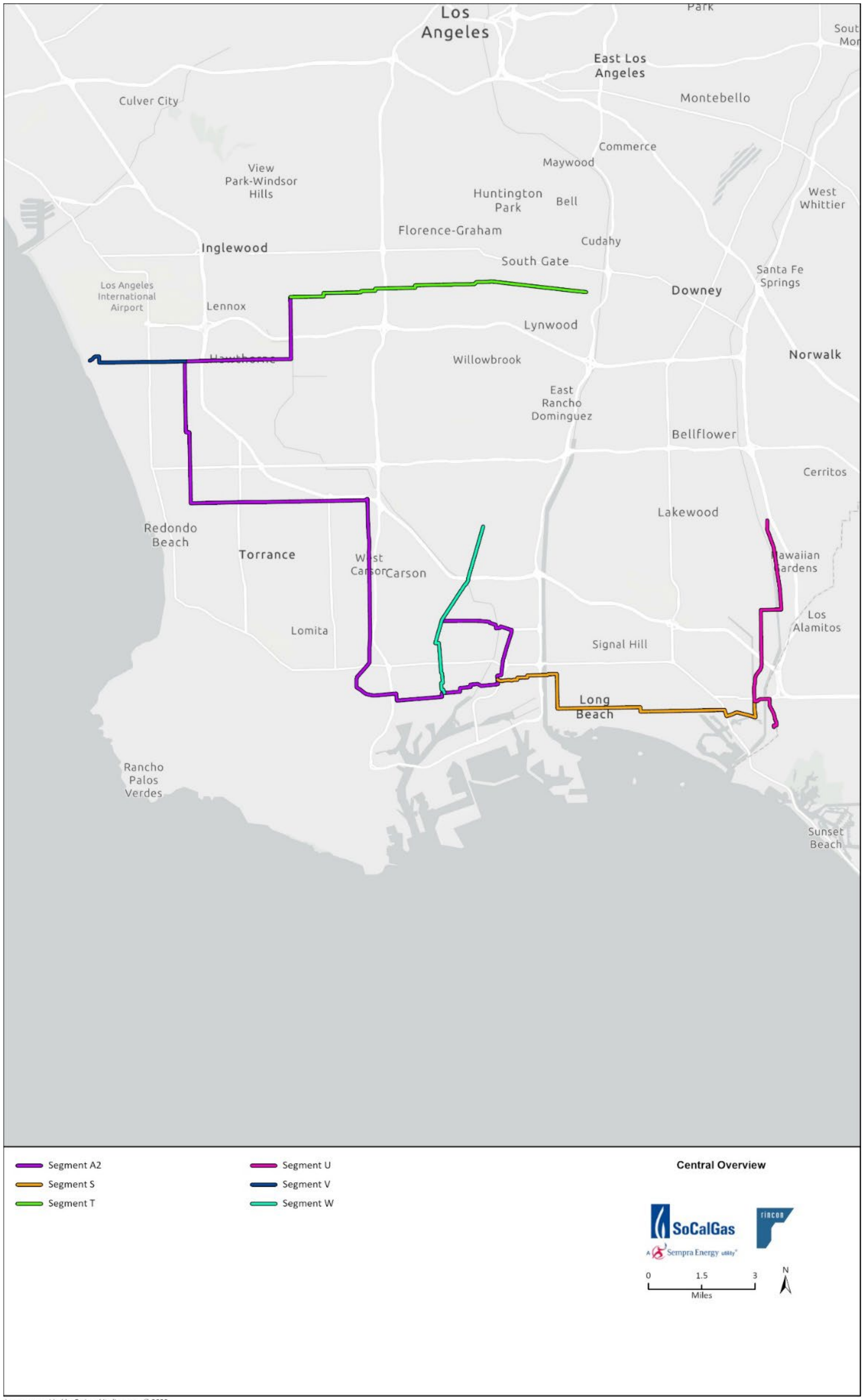


Figure 4 Pipeline Segments within the Central Zone Overview Map



1.3.1 Alliance for Renewable Clean Hydrogen Energy System

Two of the pipeline segments included in the conceptual pipeline routes have been identified to be included in the California Hydrogen Hub through the Alliance for Renewable Clean Hydrogen Energy System (ARCHES). ARCHES is California's public-private hydrogen hub consortium and has been selected to receive up to $1.2 billion in funding from the U.S. Department of Energy for the state's hydrogen hub. The two segments are Segment C in the Connection Zone and Segment B in the Collection Zone.

1.3.2 Routing Study Preferred Routes

As described further in the Routing Study, four preferred route configurations have emerged that fulfill Angeles Link's purpose. The four Preferred Route Configurations have been titled A, B, C, and D. The four Preferred Route Configurations share the common characteristics of delivering clean renewable hydrogen from third party production locations in San Joaquin Valley and Lancaster to Central and Southern California, interconnecting with ARCHES Hydrogen Hub areas through the Connection, Collection and Central Zones.

The four Preferred Route Configurations include the following pipeline segments shown in Table 1.

Table 1 SoCalGas Routing Study Preferred Route Configurations

Zone	Segment	Preferred Route Configuration			
		A	B	C	D
Connection	C *(ARCHES Segment)*	✓	✓	✓	✓
	R	✓	✓	✓	✓
Collection	B *(ARCHES Segment)*	✓	✓	✓	✓
	E		✓	✓	
	G				✓
	I				✓
	J				✓
	K	✓		✓	✓
	L	✓		✓	✓
	M		✓	✓	
	Y	✓	✓	✓	
Central	A	✓	✓	✓	✓
	D	✓	✓	✓	✓
	S	✓	✓	✓	✓
	T	✓	✓	✓	✓
	U	✓	✓	✓	✓
	V	✓	✓	✓	✓
	W	✓	✓	✓	✓
	Y	✓	✓	✓	✓

This Permitting Analysis does not analyze the potential environmental review and permitting approvals that may apply to portions of the fifth route identified in the Routing Study. However, similar environmental review and permitting approvals as identified in this Permitting Analysis would likely apply to the portions of the fifth route that have not yet been reviewed. Furthermore, additional permitting analysis for a selected configuration for Angeles Link would take place as the final route and alignment is selected and refined in future phases of Angeles Link.

Chapter 2 Technical Approach

Permitting and regulatory requirements are identified herein at a conceptual level considering potentially applicable general federal, state, and regional requirements and existing pipeline corridors or public right of way (ROW). The permit evaluation focused on regulations that could create constraints to permitting certain pipeline segments.

2.1 Jurisdictional Agencies

The desktop analysis evaluated federal, state, local jurisdictional lands, land owned/managed by special districts, military bases, highway and railroad crossings, and aqueduct crossings to determine potential permits and authorizations required for the Project. Federal, state, and local jurisdictional lands included, but were not limited to, National Park Service (NPS), Bureau of Land Management (BLM), Bureau of Reclamation (BOR), United States Forest Service (USFS), California Department of Parks and Recreation (State Parks), California State Lands Commission (CSLC), and county parks. The analysis used a corridor width of 100 feet (50 feet each side of the conceptual pipeline corridors provided by SoCalGas) to account for potential encroachment in jurisdictions directly adjacent to the potential pipeline routes, as well as the space necessary to lay the pipelines. The analysis included a review of the following databases:

- California Protected Areas Database
- BLM CA National Historic and Scenic Trails
- BLM National Surface Management Agency
- State of California Geoportal
- U.S. Department of Transportation/Bureau of Transportation Statistics National Transportation Atlas Database
- ESRI 2024

The permits and authorizations presented in the Permit Analysis were based on the current regulations and the latest information provided by agencies involved in natural gas or pipeline permitting and oversight. Timeframes for permit review and approval were based on regulatory/agency published timeframes as listed by the permitting agencies through publicly available resources, as well as on SoCalGas's and the consultant's experience with the applicable agencies and pipeline infrastructure permitting.

2.2 CEQA and NEPA Lead Agencies

The Permit Analysis assumes the California Public Utilities Commission (CPUC) will act as the lead agency that conducts the environmental review for the Project under CEQA.

The Permit Analysis assumes that a federal action (e.g., federal funding and/or discretionary permitting) will trigger NEPA review and that regulations and guidelines for key federal landowners (e.g., BLM, USFS) will need to be considered for the identification of the potential

NEPA lead agency. Section 40 CFR 1508.5 of the Council on Environmental Quality Regulations addresses cooperating agencies, which are Federal agencies other than a lead agency which have jurisdiction by law or special expertise with respect to any environmental impact involved in a proposal or reasonable alternative. Federal agencies may enter into a Memorandum of Understanding (MOU) to document the roles, responsibilities and commitments of the lead agency and cooperating agencies pursuant to NEPA and implementing regulations.

2.3 Biological and Aquatic Resources

A literature review was conducted and desktop analysis for the potential occurrence of regulated biological resources within or adjacent to potential pipeline segments. The analysis included a biological study area, defined as the footprint of the potential pipeline segments and a 100-foot survey buffer beyond the limits of the footprint of the pipelines, which was reviewed for sensitive biological resources including special-status plant and wildlife species, designated critical habitat, and potential jurisdictional waters. The analysis included a review of the following databases and literature sources to provide site context and physical characteristics, as well as identification of potential special status species[13] that may occur:

- California Department of Fish and Wildlife (CDFW) California Natural Diversity Database (CNDDB)
- United States Fish and Wildlife Service (USFWS) Critical Habitat Portal
- USFWS National Wetlands Inventory Mapper
- United States Geological Survey National Hydrography Dataset

Using aerial photographs and imagery from Google Earth Pro to view the general conditions of the study area (e.g., disturbed, developed, or undisturbed), the results of the queries above were used to evaluate whether any special status species, or jurisdictional waters occur or have the potential to occur within the study area. The assessment was limited to a desktop analysis; site conditions were not field verified.

A 5-mile search area was queried using the CDFW CNDDB to establish a list of special status species recorded in the region. Based on the condition and habitat quality of the study area determined through the desktop review, the CNNDB list was used to assess the potential for species to occur within the study area. The species evaluated were limited to state and federally listed (i.e., threatened, endangered, proposed, candidate) and fully protected species. Species determined to have potential to occur within the study area included CNDDB observations that overlapped the potential pipeline segments and/or adjacent sightings within 5 miles for which suitable habitat may be present within the study area. For the species observations, information such as, but not limited to, date of most recent visit to the site (element date), presence (i.e., extant vs. extirpated), habitat requirements, and known ranges were considered to determine if a species would be included or excluded. A specific species observation date cutoff was not used to exclude species. The USFWS Critical Habitat Portal was queried and any critical habitat overlapping the study area was considered in the analysis. The USFWS National Wetlands

[13] Special status species are state and federally listed (i.e., threatened, endangered, proposed, candidate) and fully protected species.

Inventory mapper and the United States Geological Survey National Hydrography Dataset were also queried to identify potential jurisdictional water resources documented or otherwise preliminarily mapped within the study area. Potential jurisdictional waters overlapping the study area were considered in the analysis.

The anticipated permits and authorizations presented in the Permit Analysis were based on the species identified as having potential to occur and on current regulations for impacts to federally and state protected plant and wildlife species, fully protected species, waters of the U.S., waters of the state, and lake and/or streambed impacts. In addition, qualified Rincon biologists reviewed existing habitat conservation plans (HCP) and programmatic permits for applicability to the potential pipeline segment locations and construction activities.

2.4 Study Assumptions

General Analysis Assumptions

General assumptions used during the evaluation of the potential pipeline segments are provided below.

- The evaluation herein is based on the conceptual pipeline routes (approximately 1,300 miles) identified in SoCalGas's Routing Study.
- Evaluation of biological habitats and resources is based on a desktop level analysis. No field surveys were performed.
- Pipelines will be constructed underground to the extent feasible and impacts from construction will be temporary.
- The analysis used a corridor width of 100 feet (50 feet each side of the conceptual pipeline corridor provided by SoCalGas) to account for potential impacts to resources and encroachment, as well as the space necessary to lay the pipelines.
- As an intrastate clean renewable hydrogen pipeline, Angeles Link is not expected to be subject to Federal Regulatory Energy Commission jurisdiction under the Natural Gas Act.
- The CPUC will require a permit for Angeles Link, which would require SoCalGas to submit an application for a Permit to Construct (PTC) or a Certificate of Public Convenience and Necessity (CPCN).
- Construction of the pipeline segments will involve a state discretionary action that will trigger CEQA review.
- Construction of the pipeline segments will likely involve a federal action (e.g., federal funding and/or discretionary permitting) that will trigger NEPA review.
- Permit times provided in this analysis are based on regulatory requirements or published agency timelines where available and otherwise based on reasonable regulatory agency turnaround time, in line with SoCalGas's and the consultant's previous experience on linear infrastructure projects. Estimated timelines are subject to change for any potential future changes to clean renewable hydrogen-related permitting procedures.

- A Phase I cultural resources assessment has not been performed; however, it is assumed the Project will comply with Section 106 of the National Historic Preservation Act and undergo tribal consultation through AB 52 pursuant to CEQA.
- Pipelines within conceptual corridors can be constructed in accordance with current regulatory specifications (e.g., infrastructure spacing). Future modifications to regulations may result in changes to the conclusions of this analysis.
- Pipeline construction and installation is not anticipated to require permits from the California Air Resources Board (CARB) or California's local air districts (either Air Quality Management Districts or Air Pollution Control Districts).
- This analysis focused on potential permitting needs for construction of Angeles Link's potential pipeline segments. This analysis did not evaluate requirements for potential appurtenant facilities that may be constructed to support the pipeline system (e.g., compressor stations). This analysis also did not account for potential permits needed for operation of the Project. Potential permits required for construction of appurtenant facilities and operation of the Project may be analyzed as more details on the Project develop in future phases.
- This analysis does not evaluate potential permitting requirements related to third-party clean renewable hydrogen production facilities or third-party storage facilities, as those would be constructed and operated by third parties.

Chapter 3 Jurisdiction and Permit Identification

The section describes the federal, state, regional agencies and land owned/managed by special districts that may have discretionary permitting jurisdiction over some or all of Angeles Link. Table 2 provides the pipeline segment, zone (i.e., Collection, Connection Central), counties, cities and approximate mileage of potential pipeline route crossing a particular jurisdiction. Additional permits that may be required for the construction of certain pipeline segments are detailed in Appendices A, B, and C.

3.1 Federal Jurisdiction

Several federal agencies may have discretionary approval where pipeline segments traverse their lands. These agencies, along with their potential permits/authorizations, are described below.

3.1.1 Bureau of Land Management

The BLM manages 245 million acres of public lands and 700 million acres of mineral estate in 12 main regional offices and headquarter offices in Colorado and in Washington, DC. The BLM manages public lands and subsurface estate under its jurisdiction under the Federal Land Policy and Management Act, which became law in 1976 and other laws/regulations such as NEPA and the Bipartisan Infrastructure Law (BLM 2024).

Permit Authorization: Permits from the BLM require the filing of a Standard Form (SF)-299 form (Application for Transportation, Utility Systems, Telecommunications and Facilities on Federal Land) and Plan of Development document and ultimately the approval of a ROW grant.

3.1.2 Bureau of Reclamation

The Bureau of Reclamation manages, develops, and protects water and related resources in the interest of the American public. The BOR is the largest wholesaler of water in the country and is also the second largest producer of hydroelectric power in the United States.

Permit Authorization: Permits from the BOR are required for use of BOR land and require the filing of a SF-299 form and issuance of a use authorization (43 Code of Federal Regulations [CFR] Subpart C).

3.1.3 National Park Service

The NPS manages national parks, most national monuments, and other natural resources, and historical and recreational properties, such as the Mojave National Preserve.

Permit Authorization: Permits from the NPS are required for use of NPS land and require the filing of a SF-299 form and ultimately the approval of a ROW permit (NPS 2024).

3.1.4 United States Forest Service

The USFS manages the 191 million acres of National Forests "to improve and protect the forest, to secure favorable watershed conditions, and to furnish a continuous supply of timber for the use of citizens of the United States." Forest management objectives have since expanded and evolved to include ecological restoration and protection, research and product development, fire hazard reduction, and the maintenance of healthy forests (Forest Service U.S. Department of Agriculture [FS USDA] 2024a).

<u>Permit Authorization</u>: Permits from the USFS require the filing of a SF-299 and the approval of a special-use authorization, which is a legal document such as a permit, term permit, lease, or easement, which allows occupancy, use, rights, or privileges of agency land. The authorization is granted for a specific use of the land for a specific period of time (FS USDA 2024b).

3.1.5 United States Department of Defense

United States Army Corps of Engineers

The United States Army Corps of Engineers (USACE) is the engineering branch of the U.S. Army. The USACE Regulatory Program evaluates permit applications for construction activities that occur in the Nation's waters, including wetlands. Section 404 of the Clean Water Act (CWA) establishes a program to regulate the discharge of dredged or fill material into waters of the United States, including wetlands. Activities in waters of the United States regulated under this program include fill for development, water resource projects (such as dams and levees), infrastructure development (such as highways and airports) and mining projects (United States Environmental Protection Agency 2024).

<u>Permit Authorization</u>: Angeles Link may trigger a USACE permit because of a waterbody crossing.

The USACE Regulatory Program launched a new national online application portal and management platform called the Regulatory Request System. The Regulatory Request System allows users to apply for individual and general permits using online forms and is available at https://rrs.usace.army.mil/rrs

United States Marine Corps

The United States Marine Corps (USMC) is the maritime land force service branch of the United States Armed Forces. There are five USMC bases in California, including Marine Corps Air Ground Combat Center located in San Bernardino County, MCAS Miramar and Marine Corps Base Camp Pendleton in San Diego County.

<u>Permit Authorization</u>: Use of Marine Corps property requires a ROW Grant to authorize pipeline facilities.

United States Air Force

The United States Air Force (USAF) is the air service branch of the United States Armed Forces. Edwards Air Force Base in San Bernardino County is the only USAF facility in proximity to Angeles Link.

Permit Authorization: Use of USAF property requires a ROW Grant to authorize pipeline facilities.

3.1.6 United States Fish and Wildlife Service

The USFWS is the federal government agency whose primary responsibility is to manage fish and wildlife resources in the public trust. USFWS administers the Endangered Species Act (ESA) and the Migratory Bird Treaty Act.

Permit Authorization: Take of a federally listed species as defined by the ESA may require a take permit as described below. Refer to Chapter 4 State and Federally Protected Plants and Wildlife for an overview of federally protected plants and wildlife species that are proximate to conceptual pipeline corridors identified in SoCalGas's Routing Study.

Federally Protected Species under ESA

A federal ESA take[14] permit may be required from the USFWS for incidental take of any federally protected fish and wildlife. The ESA take authorization could be obtained per the Section 10 Incidental Take Permit (ITP)/HCP process or the Section 7 Consultation process if there is a federal nexus (i.e., a separate federal approval required).

Separately, pursuant to Section 9 of the ESA, private parties may not take protected plants that are located on lands that are under federal jurisdiction or on other lands in violation of state laws. It is anticipated that take of any federally listed plants on federal lands could be addressed via a Section 7 consultation process.

The federal ESA Section 10 ITP process involves submitting an ITP application and an HCP for USFWS approval. The HCP includes a thorough impacts analysis and mitigation framework for each covered species. There is no statutory timeline for approval of an HCP, and the review duration can take several years depending on the complexity of the project and its potential effects on listed species.

The Section 7 consultation process is typically quicker than the Section 10 ITP process and is for use by agencies within the federal government. If a federal agency would have a role in funding, authorizing, or carrying out the Project (e.g., BLM ROW grant or Department of Energy funding), that agency could be required to complete Section 7 consultation. The agency initiates the consultation with USFWS and submits a Biological Assessment describing the effects of the proposed action on listed species (both plants and wildlife, including plants on non-federal land if affected) and designated critical habitat. USFWS then reviews the Biological Assessment, discusses any issues with the federal agency, and issues a Biological Opinion authorizing incidental take of listed species subject to protective measures included in the Biological Opinion. The federal ESA's timeline for Section 7 consultation is 135 days, though complex consultations often take longer.

[14] As defined in the federal ESA, take means "to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or to attempt to engage in any such conduct" (16 U.S.C. § 1532(19).).

Migratory Bird Treaty Act

The Migratory Bird Treaty Act prohibits the take (including killing, capturing, selling, trading, and transport) of protected migratory bird species without prior authorization by USFWS. Regulations regarding migratory bird permits (50 CFR 21) provide information on permits for "the taking, possession, transportation, sale, purchase, barter, importation, exportation, and banding or marking of migratory birds. This part also provides certain exceptions to permit requirements for public, scientific, or educational institutions, and establishes depredation orders which provide limited exceptions to the Migratory Bird Treaty Act." The USFWS Migratory Bird Permit Program issues and maintains these permits (USFWS 2024).

3.2 State Jurisdiction

3.2.1 California Public Utilities Commission

SoCalGas assumes the CPUC will require a permit for the Project, which would require SoCalGas to submit an application for a PTC or a CPCN.

Permit Authorization: SoCalGas assumes that a PTC or a CPCN will be required.

3.2.2 California Coastal Commission

The California Coastal Commission was established by voter initiative in 1972 (Proposition 20) and later made permanent by the Legislature through adoption of the California Coastal Act of 1976. In partnership with coastal cities and counties, the Coastal Commission plans and regulates the use of land and water in the coastal zone (California Coastal Commission 2024). The California Coastal Act delegates to local governments the power to enact and implement their own local coastal programs upon formal certification by the California Coastal Commission that the proposed programs are consistent with the policies and provisions of the statute. The California Coastal Act reserves a number of permanent implementation responsibilities for the California Coastal Commission, including the post-certification monitoring and periodic review of local programs (California Department of Transportation 2024a).

Permit Authorization: Activities in the Coastal Zone may require a Coastal Development Permit from the Coastal Commission and/or from a local agency, depending on whether the local agency implements a California Coastal Commission-approved local coastal program. [15]

3.2.3 California Department of Parks and Recreation

State Parks manage 280 state park units, over 340 miles of coastline, 970 miles of lake and river frontage, 15,000 campsites, 5,200 miles of trails, 3,195 historic buildings and more than 11,000 known prehistoric and historic archaeological sites (State Parks 2024).

[15] State agencies may develop their own CEQA-equivalent regulatory programs and may seek certification of those programs by the Natural Resources Agency. (Pub. Resources Code § 21080.5). This certification exempts agencies from certain requirements of CEQA (Division 13 of the Public Resources Code), because the environmental analysis involved in the regulatory program is deemed to be the functional equivalent of traditional CEQA documentation. (14 California Code of Regulations (CCR) §§ 15250-53.). Pursuant to Section 21080.5 of the California Code of Regulations, the regulatory program of the California Coastal Commission is a certified regulatory program.

Permit Authorization: State Parks may grant easements, leases and use permits, including right-of-entry and ROW permits under terms and conditions consistent with statutory authority. Public Resources Code §5012 authorizes, but does not require the Department to grant, among other things, permits and easements to public agencies for utilities and public roads and to grant other utility easements.

3.2.4 California State Lands Commission

The State Lands Commission manages about four million acres of tide and submerged lands and the beds of natural navigable waterways (rivers, streams, lakes, bays, estuaries, inlets, and straits) as well as “school lands” (CSLC 2024).

Permit Authorization: The use of State Lands requires the Application for Use of State Lands with the ultimate approval of a permit or lease. In the case of long-term use, a lease would be required.

3.2.5 California Department of Transportation

California Department of Transportation (Caltrans) manages State highways and also allows for non-transportation uses such as utility infrastructure that delivers water, power, and telecommunications (California Department of Transportation 2024b).

Permit Authorization: The use of Caltrans ROW requires the approval of an encroachment permit. Caltrans would typically act as a responsible agency.

3.2.6 California Department of Water Resources

The California Department of Water Resources (DWR) manages the State’s water resources, systems, and infrastructure, including the State Water Project. DWR is responsible for the construction, maintenance, evaluation, and safety of a number of water infrastructure facilities, including 34 storage facilities, 21 dams, and 705 miles of canals and aqueducts. The State Water Project is the fourth largest producer of energy in the state, using 5 hydroelectric generating plants and 4 hybrid pumping/generating plants (DWR 2024).

Permit Authorization: Encroachment into the DWR ROW requires a DWR Encroachment Permit. The encroachment permit is written authorization that allows the Permittee permission for specific facilities to be installed/altered within DWR's ROW. These permits are subject to California Code of Regulations, Title 23, Division 2, Chapter 6, Articles 600-635 and Water Code Section 12899.

3.2.7 California State Water Resources Control Board

The State Water Board and the nine Regional Water Quality Control Boards administer the CWA and the Porter-Cologne Water Quality Control Act and have the regulatory responsibility for the water quality of nearly 1.6 million acres of lakes, 1.3 million acres of bays and estuaries, 211,000 miles of rivers and streams, and about 1,100 miles of California coastline (State Water Resources Control Board 2024).

Permit Authorization: Discharge of dredged or fill materials into waters of the state require a water quality certification under Section 401 of the CWA and the Porter-Cologne Water Quality Control Act.

3.2.8 California Department of Fish and Wildlife

An additional key permitting consideration is the California Endangered Species Act (CESA). Under CESA, an ITP is required for take of state protected species pursuant to CESA Section 2081. SoCalGas intends to avoid state listed species, riparian habitat, or undisturbed areas, where feasible. Depending on circumstances, avoidance and minimization measures (e.g., fencing, seasonal restrictions, monitoring) may preclude the need for an ITP. An ITP cannot be issued for fully protected species unless the fully protected species is conserved and managed as a covered species under an approved Natural Community Conservation Plan (NCCP). In the absence of an NCCP, fully protected species should be avoided, which is also consistent with SoCalGas practices. Refer to Chapter 4 State and Federally Protected Plants and Wildlife for an overview of state protected plants and wildlife species that are proximate to conceptual pipeline corridors identified in SoCalGas's Routing Study.

State Protected Species

An ITP under Section 2081(b) of the California Fish and Game Code from the CDFW may be required for impacts to any CESA listed species.[16] This approval requires that take be minimized and fully mitigated. Mitigation must be proportionate to the impacts. CDFW cannot issue licenses or permits for incidental take of "Fully Protected" species unless the fully protected species is conserved and managed as a covered species under an approved NCCP, or in certain limited circumstances that would not be applicable to the Project.

The Native Plant Protection Act allows for the incidental removal of endangered or rare plant species within a ROW to allow a public utility to fulfill its obligation to provide service to the public. Additionally, under Fish and Game Code Section 1913, the owner of land where a rare or endangered native plant is growing is required to notify CDFW at least ten days in advance of changing the land use to allow for salvage of the plant. If a listed plant species is present and Section 1913 does not apply, then a Section 2081 ITP may be required.

The Western Joshua Tree Conservation Act prohibits the take of any western Joshua tree in California. The Western Joshua Tree Conservation Act authorizes CDFW to issue permits for the incidental take of one or more western Joshua trees if the permittee meets certain conditions.

[16] As defined under the California ESA, take means "hunt, pursue, catch, capture, or kill, or attempt to hunt, pursue catch, capture, or kill" (Fish & Game Code § 86).

3.3 Special Districts and Non-Governmental Agencies

Certain pipeline segments may traverse land owned/managed by special districts, including, but not limited to, recreation and conservation authorities, and joint powers authorities. These special districts may have discretionary authority over discrete pipeline segments. Additionally, certain potential pipeline segments may traverse lands owned by non-governmental organizations, including conservation lands, mitigation lands, and preserves. Such lands may serve as habitat or wetland mitigation properties or conservation areas associated with regional HCPs. While non-governmental landowners do not function as regulatory agencies, restrictions imposed by conservation easements or covenants may preclude any construction or development and should be considered significant constraints, particularly if acquisition of new or expanded ROW within such lands would be required.

Chapter 4 State and Federally Protected Plants and Wildlife

This section provides an overview of state and federally protected plants and wildlife species that are proximate to conceptual pipeline corridors identified in SoCalGas's Routing Study. A federal ESA take permit and/or CESA Section 2801 take permit may be required depending on the final selected pipeline route and alignment.

Protected species potentially occurring along or near the **Connection Zone**:

Wildlife	Plants
▪ Arroyo toad (FE) ▪ Blunt-nosed leopard lizard (FE, SE, FP) ▪ Coastal California gnatcatcher (FT) ▪ Coachella Valley fringe-toed lizard (FT, SE) ▪ Crotch's bumble bee (SC) ▪ Desert bighorn sheep (FP) ▪ Mojave desert tortoise (FT, ST) ▪ Golden eagle (FP) ▪ Giant kangaroo rat (FE, SE) ▪ Gila woodpecker (SE) ▪ Least Bell's vireo (FE, SE) ▪ Mohave ground squirrel (ST) ▪ San Joaquin antelope squirrel (ST) ▪ San Joaquin kit fox (FE, ST) ▪ Santa Ana sucker (FT) ▪ Southern rubber boa (ST) ▪ Willow flycatcher (SE), southwestern willow flycatcher (FE, SE) ▪ Steelhead – southern California DPS (FE, SC)* ▪ Stephens' kangaroo rat (FE, SE) ▪ Swainson's hawk (ST) ▪ Tipton's kangaroo rat (FE, SE) ▪ Tricolored blackbird (ST) ▪ Western burrowing owl (SSC and anticipated SC)[17] ▪ Western pond turtle (proposed FT) ▪ Western spadefoot (proposed FT) ▪ White-tailed kite (FP)	▪ California jewel flower (FE, SE) ▪ Coachella Valley milk-vetch (FE) ▪ Kern mallow (FE, SE) ▪ San Joaquin woollythreads (FE) ▪ Western Joshua tree (SC, WJT Conservation Act)[18]

* Southern California steelhead occurs near conceptual pipeline corridors in the Santa Ana River and the conceptual pipeline corridors traverse a concrete lined portion of the Santa Ana River downstream of the Prado Dam. However, the species is not anticipated to occur downstream of the Prado Dam and no impacts to the species are anticipated based on the conceptual pipeline corridors. As such, the species is not further discussed.

FE = Federally Endangered FT = Federally Threatened SE = State Endangered
ST = State Threatened SC = State Candidate FP = State Fully Protected SSC = State Species of Special Concern

[17] Western burrowing owl is currently petitioned for listing under CESA and is likely to be listed as a State Candidate species by summer 2024. If the species is listed and Project activities cannot avoid impacts to this species, an ITP may be required.

[18] CNDDB occurrences for western Joshua Tree do not occur within 5 miles of the potential segments identified in the Connection Zone, but certain potential pipeline segments within the Connection Zone are within known range of this species. The Western Joshua Tree Conservation Act prohibits the importation, export, take, possession, purchase, or sale of any western Joshua tree in California unless authorized by CDFW.

Protected species potentially occurring along or near the **Collection Zone** include:

Wildlife	Plants
▪ Arroyo toad (FE)	▪ Bakersfield cactus (FE, SE)
▪ Bald Eagle (SE, FP)	▪ Braunton's milk-vetch (FE)
▪ Blunt-nosed leopard lizard (FE, SE, FP)	▪ California Orcutt grass (FE, SE)
▪ California condor (FE, SE, FP)	▪ Nevin's barberry (FE, SE)
▪ Coastal California gnatcatcher (FT)	▪ San Fernando Valley spineflower (SE)
▪ Crotch's bumble bee (SC)	▪ Santa Ana River woollystar (FE, SE)
▪ Delhi Sands flower-loving fly (FE)	▪ Slender-horned spineflower (FE, SE)
▪ Mojave desert tortoise (FT, ST)	▪ Western Joshua Tree (SC, WJT Conservation Act)[20]
▪ Golden eagle (FP)	
▪ Least Bell's vireo (FE, SE)	
▪ Mohave ground squirrel (ST)	
▪ Santa Ana sucker (FT)	
▪ San Bernardino kangaroo rat (FE, SC)	
▪ San Joaquin antelope squirrel (ST)	
▪ San Joaquin kit fox (FE, ST)	
▪ Willow flycatcher (SE), southwestern willow flycatcher (FE, SE)	
▪ Swainson's hawk (ST)	
▪ Tipton kangaroo rat (FE, SE)	
▪ Tricolored blackbird (ST)	
▪ Unarmored threespine stickleback (FE, SE, FP)	
▪ Vernal pool fairy shrimp (FT)	
▪ Western burrowing owl (SSC and anticipated SC)[19]	
▪ Western pond turtle (proposed FT)	
▪ Western spadefoot (proposed FT)	
▪ Western yellow-billed cuckoo (FT, SE)	
▪ White-tailed kite (FP)	

FE = Federally Endangered FT = Federally Threatened SE = State Endangered
ST = State Threatened SC = State Candidate FP = State Fully Protected SSC = State Species of Special Concern

[19] Western burrowing owl is currently petitioned for listing under CESA and is likely to be listed as a State Candidate species by summer 2024. If the species is listed and Project activities cannot avoid impacts to this species, an ITP may be required.

[20] CNDDB occurrences for western Joshua Tree do not occur within 5 miles of the potential segments identified in the Collection Zone, but certain potential pipeline segments within the Collection Zone are within known range of this species. The Western Joshua Tree Conservation Act prohibits the importation, export, take, possession, purchase, or sale of any western Joshua tree in California unless authorized by CDFW.

Protected species potentially occurring along or near the **Central Zone** include:

Wildlife	Plants
▪ El Segundo blue butterfly (FE) ▪ Monarch butterfly (FC) ▪ Tricolored blackbird (ST) ▪ Crotch bumble bee (SC) ▪ Western pond turtle (proposed FT) ▪ Western spadefoot (proposed FT)	▪ None

FE = Federally Endangered FT = Federal Threatened FC = Federal Candidate
ST = State Threatened SC = State Candidate

Table 2 Segment Information

Segment	Zone	County	Cities	BLM	BOR	NPS	DoD	USFWS	USFS	CDFW	State Parks	Other State Lands[1]	State Lands Comm	Special District[2]	Other[3]	Total
Segment C	Connection	Fresno, Kings, Kern	Avenal	0.17	0.45										79.2	79.8
Segment R	Connection	Kern		2.9						0.02				0.28	78.5	81.7
Segment F	Connection	San Bernardino	Adelanto, Victorville, Barstow	75.7		1.8	4.1					1.4			69.2	152.2
Segment P	Connection	San Bernardino	Adelanto, Victorville, Apple Valley	29.2								1.4			20.2	50.8
Segment O	Connection	San Bernardino	Hesperia	16.5					0.89					0.74	34.6	52.7
Segment H	Connection	San Bernardino	Needles	43.2		41.9						2.3			4.7	92.0
Segment X	Connection	San Bernardino	–	112.0						0.13		2.3			10.1	124.7
Segment N	Connection	Orange, San Bernardino, Riverside	Chino Hills, Corona, Riverside, Moreno Valley, Banning, Beaumont, Palm Springs	0.59			3.7				4.5	0.21		2.6	66.3	78.0
Segment Q	Connection	Riverside	Palm Springs, Cathedral City, Indio, Coachella, Blythe	46.7	0.76			1.7		0.95		0.42		0.89	71.1	122.5
Segment E	Collection	Kern, Los Angeles	Lancaster	0.09			0.51								29.9	30.5
Segment M	Collection	Kern	Tehachapi										0.17	0.26	50.7	51.2
Segment L	Collection	Kern	–												10.4	10.4
Segment K	Collection	Kern, Ventura, Los Angeles	Santa Clarita	1.3					10.3	0.98	8.8			2.1	31.9	55.4
Segment Y	Collection	Los Angeles	Los Angeles, San Fernando, Burbank, Glendale, Vernon, Huntington Park, South Gate, Lynwood, Maywood, Compton, Carson												48.6	48.6
Segment D	Collection	Los Angeles	Long Beach, Carson, Lakewood, Cerritos											0.01	7.5	7.5
Segment J	Collection	San Bernardino, Riverside, Los Angeles, Orange	Cerritos, La Palma, Lakewood, Buena Park, Anaheim, Placentia, Yorba Linda, Chino, Chino Hills, Eastvale, Fontana, Jurupa Valley, Ontario, Rialto								1.9				58.3	60.2
Segment I	Collection	San Bernardino	Rialto, San Bernardino, Victorville, Adelanto						7.6						24.3	31.9
Segment G	Collection	San Bernardino, Los Angeles	Adelanto, Palmdale	0.06										0.08	39.3	39.4
Segment B	Collection	Los Angeles	Lancaster, Palmdale, Santa Clarita, Los Angeles	0.28											45.5	45.7
Segment T	Central	Los Angeles	Inglewood, South Gate, Los Angeles, Lynwood												8.6	8.6
Segment A2	Central	Los Angeles	El Segundo, Los Angeles, Carson, Long Beach, Redondo Beach, Hawthorne, Inglewood, Torrance, Manhattan Beach												27.6	27.6
Segment V	Central	Los Angeles	El Segundo, Los Angeles												2.9	2.9
Segment W	Central	Los Angeles	Carson, Los Angeles												5.2	5.2
Segment S	Central	Los Angeles	Long Beach, Los Angeles											0.12	9.0	9.2
Segment U	Central	Los Angeles, Orange	Lakewood, Long Beach, Seal Beach, Cerritos											0.03	7.1	7.1

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Appendix A

Connection Zone: Summary of Agencies, Permitting Role, and Agency Permitting Review Timeline for Potential Pipeline Segments within Connection Zone

Connection Zone: Summary of Agencies, Permitting Role, and Agency Permitting Review Timeline for Potential Pipeline Segments within Connection Zone

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months) [21]	Estimated Review Duration (months) [22]
Lead agency for NEPA review	Federal discretionary action	Environmental Impact Statement (EIS)	Lead agency variable. NEPA compliance would be required for work on federal land (e.g., BLM) and for the issuance of federal permits or if federal funding is provided. The federal agency may prepare a joint EIS/Environmental Impact Report (EIR) in coordination with state, tribal, and local agencies.	▪ The NEPA process may occur concurrently with the CEQA process. ▪ The NEPA process may occur concurrently with other federal permits applications and review processes. ▪ The following permits are potential NEPA triggers and may be processed concurrently while NEPA review is being undertaken, but may not be issued until the NEPA process is complete: ▫ BLM ROW Grant ▫ BOR ROW Grant ▫ USFS Special Use Permit ▫ USFWS Section 7 Consultation Biological Opinion ▫ USFWS Section 10 Habitat Conservation Plan ▫ Department of Defense (USMC) ROW Grant/Easement ▫ NPS ROW Permit ▪ Completion of the necessary fieldwork, technical studies, and preparation of the Draft EIS can take 12-18 months or longer to complete. ▪ The NEPA process must be complete within 24 months unless a longer period is provided for in writing.	24	24-36
BLM	BLM encroachment/Areas of Critical Environmental Concern (ACES)	ROW Grant Easement (Standard Form-299)	Various potential segments within the Connection Zone occur within BLM-managed lands. Where the segments occur within BLM ACECs, applicable BLM Land Management Plans should be reviewed, and additional findings and protective measures may be required for BLM approval. A Plan of Development may need to be prepared prior to approval of the ROW grant.	▪ NEPA must be complete prior to approval of ROW grant approval. ▪ Environmental permits (biological opinion, waters permits, etc.) must be obtained prior to ROW grant approval.	N/A	12-18
BOR	BOR encroachment	Application for Transportation and Utility Systems and Facilities on Federal Lands (Standard Form-299)	A portion of Segment C and Segment Q intersect BOR land. Authorization would be required for utility crossings on federal land.	▪ NEPA must be complete prior to approval. ▪ Environmental permits must be obtained prior to ROW grant approval.	N/A	12-18
DoD	USMC encroachment	Easement Acquisition	A portion of Segment F intersects USMC Logistics Base Barstow and USMC Logistics Base Yermo Annex.	▪ NEPA must be complete prior to approval of ROW/easement. ▪ Environmental permits may be required prior to approval of ROW/easement.	N/A	12-18

[21] The regulatory/agency published timeframes provide timeframes for permit review and approval, as listed by the permitting agencies through publicly available resources. Where agency-published review and approval timeframes were not publicly available, a timeframe was not provided, and the column was noted as "N/A". Agency reviews may exceed published timelines.

[22] The estimated review duration provides an estimated range from typical to longest likely time for permit review and approval based on the consultants' experience with the applicable agencies and pipeline infrastructure permitting, as well as typical timeframes provided by SoCalGas's Land and Right-of-Way organization on previous projects (e.g., Pipeline Safety Enhancement Plan). Estimated review duration does not include time for completion of potential fieldwork, technical studies, or preparation of reports that may be needed to support SoCalGas's submission of the application for approval. Estimated timelines also assume some applications for approvals would overlap in time and could be prepared and processed concurrently with CEQA/NEPA timelines. See the Permit Dependencies and Notes column for permits requiring CEQA/NEPA completion prior to approval.

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months) [21]	Estimated Review Duration (months) [22]
DoD	USAF encroachment	Easement Acquisition	A portion of Segment F intersect George Air Force Base and Connection Segment N intercepts March Air Reserve Base.	▪ NEPA must be complete prior to approval of ROW/easement. ▪ Environmental permits may be required prior to approval of ROW/easement.	N/A	12-18
NPS	Mojave National Preserve encroachment	ROW Permit	Segments F and H intersect the Mojave National Preserve. Work with NPS typically requires a ROW permit; however, NPS enforces strict limitations to development within the Mojave National Preserve. Segments should be re-routed to avoid Mojave National Preserve	▪ NEPA must be complete prior to approval of ROW Permit. ▪ Avoidance recommended. .	N/A based on avoidance	N/A based on avoidance
NPS and/or U.S. Forest Service	Historic and designated trail crossings	Agency Coordination	Certain potential pipeline segments within the Connection Zone may cross the following National Historic Trails: ▪ Segment N within the Connection Zone may intersect the Juan Bautista De Anza National Historic Trail in the city of Moreno Valley. An encroachment permit from the city of Moreno Valley may be required. ▪ Certain potential pipeline segments within the Connection Zone intersect may Old Spanish National Historic Trail at various points, within public ROW and private unpaved roads. Permits to impact public ROW would be anticipated via encroachment permit processes of local jurisdictions. Rights to impact private roads would be secured by Lands during the easement/temporary right of entry (TRE) negotiation. ▪ Segment R may cross the Butterfield Overland National Historic Trail (BOHNT) in unincorporated Kern County. A permit to impact this public ROW would be anticipated via an encroachment permit from the Kern County Department of Public Works. Segment M may intersect the BONHT in unincorporated Riverside County. ▪ Certain potential pipeline segments within the Connection Zone may intersect the Pacific Crest Trail: ▫ Segment N in the unincorporated Riverside County . Impacts to the public ROW would be anticipated via an encroachment permit from the Riverside County Department of Transportation. Pursuant to 16 U.S.C. § 1248(a), the Secretary of the Interior or the Secretary of Agriculture may grant easements and ROW across components of the national trails system in accordance with the laws applicable to the National Park System and the National Forest System, respectively. However, given the location of the trails within paved roadways, a ROW grant is not anticipated to be required. Site-specific analysis may be required for each crossing to determine which agency holds jurisdiction, and whether pipeline crossings are permitted.	▪ Coordination with the agencies for ministerial encroachment permits may occur concurrently with NEPA.	N/A	N/A

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months) [21]	Estimated Review Duration (months) [22]
State Historic Preservation Office (SHPO)	Cultural and/or historical resources	Section 106 National Historic Preservation Act Compliance	Required if there are potential impacts to cultural and/or historical resources that are listed or eligible for listing on the National Register of Historic Places. For portions of the segments located on BLM land, preparation of a Class III cultural resource inventory of the area of potential effect, including records search, intensive pedestrian survey, and technical report, may be required. Federal and CEQA lead agencies may conduct government-to-government consultation with Native American tribes and other individuals and organizations with knowledge of, or concerns with, historic properties in the segment area. If historic properties or cultural resources are identified, additional work such as testing, evaluation, data recovery, and archaeological monitoring may be warranted and consultation with SHPO may be required.	▪ The Section 106 process may occur concurrently with NEPA. ▪ If required, SHPO concurrence may occur prior to completion of NEPA. ▪ Consultation duration dependent on the number of tribal territories included in the consultation and potential negotiations regarding mitigation measures.	2	8-18
USFS	USFS encroachment	Special Use Permit (SUP)	Certain potential pipeline segments within the Connection Zone may occur within San Bernardino National Forest.	▪ NEPA must be complete prior to approval of SUP. ▪ Environmental permits may be required prior to approval of SUP.	N/A	12-18
USFWS	Coachella Valley National Wildlife Refuge (NWR) encroachment	ROW Permit and SUP	Connection Segment Q may cross the Coachella Valley NWR. This NWR contains Critical Habitat for the Coachella Valley fringe-toe lizard and Coachella Valley milk-vetch. A ROW permit may be required to modify existing SoCalGas pipeline ROW permits. Pre-application consultation would be recommended, followed by submittal of a SF-299, Application for Transportation and Utility Systems and Facilities on Federal Lands. The USFWS may also request application of a SUP to cover temporary construction activities. Both permits can be processed concurrently.	▪ NEPA must be completed prior to the issuance of a ROW permit or SUP. ▪ Environmental permits should be in hand prior to issuance of ROW permit or SUP.	N/A	12-18
USFWS	Federally listed species	ESA Section 7 Consultation Biological Opinion	A federal ESA Biological Opinion may be required from USFWS for any federally listed species where a federal nexus is present (e.g., BLM and USFS lands), per ESA Section 7. There is federally designated critical habitat for Mojave desert tortoise, coastal California gnatcatcher, least Bell's vireo, southwestern willow flycatcher, arroyo toad, Coachella Valley fringe-toed lizard, and Coachella Valley milk-vetch near potential pipeline segments within the Connection Zone. Additionally, the certain potential pipeline segments also contain habitat for many listed species for which critical habitat is not designated (i.e., San Joaquin kit fox, giant kangaroo rat, Tipton kangaroo rat, Stephens' kangaroo rat, Santa Ana sucker, western spadefoot, western pond turtle, Kern mallow). A CWA Section 404 Permit would be anticipated to provide a federal nexus for aquatic and riparian species (e.g., arroyo toad, Santa Ana sucker, western pond turtle, least Bell's vireo, southwestern willow flycatcher).	▪ NEPA must be completed prior to the issuance of a Biological Opinion. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report to submit to USFWS can take 6-18 months to complete. ▪ Final issuance of the Biological Opinion can take 4.5-18 months.	4.5	9-18

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months) [21]	Estimated Review Duration (months)[22]
USACE	Waters of the U.S. (WOTUS)	Clean Water Act 404 Permit Nationwide Permit (NWP) 12	A CWA Section 404 Permit is required for any impacts to WOTUS, including jurisdictional wetlands, that involve the discharge of dredged or fill materials into a waterbody or wetland. NWP 12 provides coverage for the construction, maintenance, repair, and removal of pipelines and associated facilities in WOTUS, provided the activity does not result in the permanent loss of greater than ½ acre of WOTUS). New NEPA review is not required for NWP 12. A 401 Certification is also required; see State Water Resources Control Board and Regional Water Quality Control Board (RWQCB) below.	▪ Section 7 consultation must be completed prior to the issuance of NWP 12.	3	6-9
State						
Lead agency for CEQA review	State discretionary action	EIR	The state lead agency is anticipated to be the CPUC in connection with a CPCN or PTC application, and the CPUC would prepare an EIR for any discretionary approval of the Project.	▪ CEQA and NEPA processes may occur concurrently. ▪ Completion of the necessary fieldwork, technical studies can take up to 24 months to complete. ▪ CPUC review and approval of a PTC or CPCN could take up to 49 months after submittal all supporting documentation. ▪ The following permits may potentially trigger CEQA, in which case the issuing agencies could act as CEQA responsible agencies, but the permits may not be issued until the responsible agencies comply with their CEQA obligations: ▫ Caltrans ROW Encroachment ▫ CDFW ITP ▫ CDFW Avoidance Plan ▫ CDFW Lake and Streambed Alteration Agreement ▫ CSLC Lease ▫ DWR Encroachment ▫ RWQCB WDR/401 Certification ▫ State Parks SUP ▫ Special District Approval ▫ Regional HCP Inclusion	29	23-49
CPUC	State discretionary action	CPCN or PTC	For a CPCN, the CPUC is required to certify the "public convenience and necessity" for a project before a utility may begin construction. A PTC is a comparatively streamlined process that also requires CPUC approval before construction of specific types of projects.	▪ The CPCN/PTC process concludes with the certification of the Final EIR [23] and issuance of the CPCN or PTC.	29	23-49[24]

[23] To comply with CEQA requirements, it is also possible a Negative Declaration or Mitigated Negative Declaration may be prepared in lieu of an EIR.

[24] In June 2023, the California Public Advocates Office (Cal Advocates) analyzed development timelines of 14 recently approved and completed electric transmission projects to understand potential development and permit review timelines. For larger projects (200 kV or more subject to the CPCN process), the average duration of the development process phases included 2.4 years of pre-application planning by the developer and 3.4 years of permitting by the CPUC. For smaller projects (50 KV to 200kV subject to the Permit to Construct process), the average duration development process phases included 4 years of pre-application planning by the developer and 2.3 years of permitting review by the CPUC. While the Cal Advocates analysis focused on electrical transmission projects, the analysis provides additional context for potential permitting timelines for new pipeline infrastructure. The Cal Advocates analysis is available at https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230612-caladvocates-transmission-development-timeline.pdf.

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months) [21]	Estimated Review Duration (months)[22]
Caltrans	State highway crossings	ROW Encroachment	Potential pipeline segments within the Connection zone occur within Caltrans ROW.	▪ CEQA must be completed prior to permit issuance, and as a responsible agency, Caltrans could likely rely on the EIR. ▪ Caltrans may require evidence of inclusion in Regional HCP's if the proposed encroachment is within the boundary of an HCP.	3	6-12
CDFW	State protected species	CESA ITP	Required for take of state protected species, but cannot be issued for Fully Protected species such as the blunt-nosed leopard lizard, desert bighorn sheep, golden eagle, and white-tailed kite. Avoidance of blunt-nosed leopard lizard, desert bighorn sheep, golden eagle, and white-tailed kite habitat is recommended.	▪ CEQA must be completed prior to permit issuance, and as a responsible agency, CDFW could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete. ▪ Agency review and approval can take 4-36 months.	4	18-36
CDFW	Western Joshua tree	Western Joshua Tree Conservation Act ITP	Required authorization for take of Joshua tree, as well as trimming of live trees or removal of dead trees. The Act requires that the permittee must mitigate all impacts to, and taking of, the western Joshua tree but includes provisions that allow permittees to pay specified fees in lieu of conducting mitigation activities.	▪ CEQA must be completed prior to permit issuance, and as a responsible agency, CDFW could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-9 months to complete. ▪ Agency has 30 days to approve or deny permit application after confirming a complete application.	1	3-10
CDFW	Fully Protected species blunt-nosed leopard lizard, desert bighorn sheep, golden eagle, and white-tailed kite	Avoidance Plan	CDFW can potentially approve an Avoidance Plan for a fully protected species. An Avoidance Plan may include measures such as seasonal work and HDD activities to avoid impacts to a fully protected species. Based on survey results, CDFW may approve a BNLL Avoidance Plan; however, there are no specified timelines and CDFW is not required to approve.	▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete.	N/A	N/A
CDFW	Lake/streambed impacts	Section 1600 Lake or Streambed Alteration Agreement	Needed for impacts to CDFW jurisdictional drainages or drainage vegetation. Requires seasonal surveys. Likely a CEQA Responsible Agency.	▪ CEQA must be complete prior to permit issuance, and as a responsible agency, CDFW could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-9 months to complete.	3	6-9
CDFW	CDFW mitigation lands/preserves encroachment	SUP	Segment X may cross Havasu National Wildlife Refuge, Segment Q may cross Coachella Valley Ecological Reserve, and Segment R may cross Lokern Ecological Reserve. These lands serve as mitigation lands/preserves and acquiring new or expanded ROW could be difficult.	▪ Avoidance is recommended.	N/A based on avoidance	N/A based on avoidance
CEQA Lead Agency	Cultural and/or tribal resources	AB 52 Tribal Consultation	As part of the CEQA review, the lead agency would conduct government-to-government consultation pursuant to AB 52 (Public Resources Code § 21080.3.1 et seq.) The lead agency would consult with potentially impacted Native American tribes with knowledge of, or concerns with, cultural or tribal resources in the segment area. If cultural or tribal resources are identified, additional work such as testing, evaluation, data recovery, and archaeological monitoring may be warranted.	▪ The AB 52 consultation may occur concurrently with the CEQA review. ▪ Consultation duration dependent on the number of tribal territories included in the consultation and potential negotiations regarding mitigation measures. ▪ Duration would likely be consistent with estimated review duration for overall CEQA review.	N/A	23-49

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months) [21]	Estimated Review Duration (months)[22]
California Department of Water Resources	Aqueduct crossings and easement encroachments	Encroachment Permit	Needed to perform work and install assets within State Water Project ROW.	▪ CEQA must be complete prior to permit issuance.	3	6-12
CSLC	CSLC encroachment	CSLC Leases	Various potential segments within the Connection Zone may traverse CSLC land. Likely a CEQA Responsible Agency.	▪ CEQA must be complete prior to permit issuance.	6-24	6-24
Coachella Valley Mountains Conservancy	Coachella Valley Mountains Conservancy encroachment	ROW Grant/Easement Acquisition	Segment N and Segment Q may cross Coachella Valley Mountains Conservancy managed lands.	▪ CEQA must be complete prior to permit issuance. ▪ Permissions as a Participating Special Entity for the Coachella Valley Multiple Species Habitat Conservation Plan is anticipated to be required.	N/A	12-18
RWQCB	WOTUS/waters of the state	Individual 401 Certification and Waste Discharge Requirement	Two different permit types for impacts to waters of the state (WDR) and when coterminous with federal jurisdiction (401 Certification). The Connection zone is within the Central Valley, Santa Ana, Colorado River, and North Coast RWQCBs. Depending on permitting approach and timing, it may be feasible for SoCalGas to pursue RWQCB permitting with the State Board rather than coordinating with multiple RWQCBs. The State Board may serve as a CEQA Responsible Agency.	▪ CEQA must be complete prior to permit issuance, and as a responsible agency, the RWQCB could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-9 months to complete.	12	12-24
State Parks	State Parks encroachment	SUP	Segment N may cross Chino Hills State Park. Public Resources Code §5012 authorizes, but does not require State Parks to grant, among other things, permits and easements to public agencies for utilities and public roads and to grant other utility easements or to perform a public service, upon application by the proper authorities	▪ CEQA must be complete prior to permit issuance.	N/A	12-18
Regional: Local/Special District/Community Plan						
Special Districts	Special district encroachment	ROW Grant/Easement Acquisition	Potential pipeline segments cross land under the ownership or jurisdiction of various special districts, including but not limited to park and recreation, and conservation districts. ROW grants and/or easement acquisition from these districts may require Board approval and thus may trigger CEQA. Depending on the nature of the scope of construction activities within each district's jurisdiction, the special district may adopt a CEQA Categorical Exemption, or may take on a Responsible Agency role.	▪ CEQA must be complete prior to ROW grant/easement issuance. ▪ Each special district may impose individual conditions of approval.	Variable	Variable
Regional HCPs ▪ Kern County Valley Floor HCP (VFHCP) ▪ West Mojave Coordinated Management Plan Regional HCP ▪ Western Riverside County	Federally listed species	ESA Take authorization	Potential pipeline segments within the Connection Zone may be located within the VFHCP; however, the VFHCP is under development and is not anticipated to be adopted in the near future. Certain potential pipeline segments within the Connection Zone may cross the West Mojave Plan (formerly West Mojave Coordinated Management Plan); however, the West Mojave Plan was invalidated in court and cannot be used. Certain potential pipeline segments within the Connection Zone may cross the Western Riverside County Multiple Species HCP,	▪ CEQA must be complete prior to issuance of Certificate of Inclusion by the Western Riverside County Multiple Species HCP, the Coachella Valley Multiple Species HCP, and Lower Colorado River MSCP HCP. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete. ▪ Timeframe for coverage under the DRECP Biological Opinion is assumed to be the same as the BLM ROW Grant Easement process timeframe as BLM is likely to process a DRECP Biological Opinion request concurrently with its overall approval for work under their jurisdiction.	N/A	12-18

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months)[21]	Estimated Review Duration (months)[22]
Multiple Species HCP			which may provide take authorization for several federally listed species.			
▪ Coachella Valley Multiple Species HCP			Certain potential pipeline segments within the Connection Zone may cross the Coachella Valley Multiple Species HCP, which may provide take authorization for several federally listed species.			
▪ Lower Colorado River MSCP HCP			Certain potential pipeline segments within the Connection Zone may cross the Lower Colorado River MSCP HCP, which may provide take authorization for several federally listed species.			
▪ Desert Renewable Energy Conservation Plan (DRECP)			Certain potential pipeline segments within the Connection Zone may be located within the DRECP. Coordination with the administering agency would be necessary to determine if coverage through the DRECP Biological Opinion could be obtained.			
Unlikely Permit Pathways[25]						
USFWS	Federally protected species	ESA Section 10 HCP	A federal ESA incidental take permit may be required from USFWS for any federally protected species when a federal nexus is absent in accordance with the Section 10 process. If no programmatic or SoCalGas specific HCP is adopted, a separate ESA take permit may be required from USFWS (i.e., Mojave desert tortoise, San Joaquin kit fox, giant kangaroo rat, Tipton kangaroo rat, Stephens' kangaroo rat, Coachella Valley fringe-toed lizard, arroyo toad, western pond turtle, western spadefoot, Santa Ana sucker, coastal California gnatcatcher, least Bell's vireo, southwestern willow flycatcher, Coachella Valley milk-vetch, California jewelflower, Kern mallow, and San Joaquin woollythreads).	▪ NEPA must be completed prior to the issuance of the HCP. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete.	48-50	48-60
CDFW	Fully Protected species blunt-nosed leopard lizard, desert bighorn sheep, golden eagle, and white-tailed kite	NCCP	CDFW can potentially authorize take under an NCCP. An NCCP can cover multiple species. Based on approved NCCPs, these types of plans have not been approved on a project-by-project basis but rather for a given region.	▪ Development and adoption of an NCCP is estimated to be 8-9 years.	47[26]	Variable

[25] The permits identified under this heading were evaluated for applicability to the Project and were determined to be unlikely permitting pathways. The Project would fully avoid Fully Protected species and take authorization under an NCCP is not anticipated. SoCalGas assumes a federal nexus will allow for take authorization under Section 7 and authorization through Section 10 will not be required.

[26] Due to a limited number of NCCPs approved, the timeframe for approval of an NCCP was taken from the best case scenarios of a CDFW-published NCCP/HCP Process Flowchart and Normative Timelines graphic (available online at https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=109210&inline). This is based on seven NCCPs approved and permitted between 1996 and 2013.

Appendix B

Collection Zone: Summary of Agencies, Permitting Role, and Agency Permitting Review Timeline for Potential Pipeline Segments within the Collection Zone

Collection Zone: Summary of Agencies, Permitting Role, and Agency Permitting Review Timeline for Potential Pipeline Segments within the Collection Zone

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months)[27]	Estimated Review Duration (months)[28]
Lead agency for NEPA review	Federal discretionary action	Environmental Impact Statement (EIS)	There would be one lead agency for the Angeles Link Project. See comments, dependencies, and timeframes on Lead Agency for NEPA review in Appendix A.			
BLM	BLM encroachment/ Areas of Critical Environmental Concern (ACES)	ROW Grant Easement (Standard Form-299)	Various potential segments within the Collection Zone occur within BLM-managed lands. Where the segments occur within BLM ACECs, applicable BLM Land Management Plans should be reviewed, and additional findings and protective measures may be required for BLM approval. A Plan of Development may need to be prepared prior to approval of the ROW grant.	▪ NEPA must be complete prior to approval of ROW grant approval. ▪ Environmental permits must be obtained prior to ROW grant approval.	N/A	12-18
DoD	USAF encroachment	Easement Acquisition	A portion of Segment E may intersect Edwards Air Force Base.	▪ NEPA must be complete prior to approval of ROW/easement. ▪ Environmental permits may be required prior to approval of ROW/easement.	N/A	12-18
NPS and/or U.S. Forest Service	Historic and designated trail crossings	Agency Coordination	Certain potential pipeline segments within the Collection Zone may cross the following National Historic Trails: ▪ Juan Bautista De Anza National Historic Trail: ▫ Segment J may intersect in the city of Ontario. The crossing is on disturbed private land and permission to impact the site would likely be acquired via the easement/temporary right of entry (TRE) process. ▫ Segment Y may intersect within existing public ROW in the cities of Los Angeles and Glendale. Permits to impact crossings in this area would likely be via an encroachment permit process administered by local jurisdictions. ▪ Old Spanish National Historic Trail (OSNHT): ▫ Segment I may intersect several times. Where the crossing lies within a public ROW, permits to impact would likely be via encroachment permit processes administered by local jurisdictions. Where Segment I may cross the OSNHT outside a public ROW and within the San Bernardino National Forest, the crossings may be subject to 16 U.S.C. § 1248(a), as described below. ▫ Segment Y may intersect in the city of Los Angeles. Permits to impact the crossing in this area would likely be via an encroachment permit process with the city of Los Angeles. ▪ Butterfield Overland National Historic Trail: ▫ Segment J may intersect in the city of Chino Hills. Permission to impact the site would likely l be acquired via the easement / TRE process. ▫ Segment Y may intersect in the city of Los Angeles. Permits to impact the crossing in this area would likely be via an encroachment permit process with the city of Los Angeles.	▪ Coordination with the agencies for encroachment permits may occur concurrently with NEPA.	N/A	N/A

[27] The regulatory/agency published timeframes provide timeframes for permit review and approval, as listed by the permitting agencies through publicly available resources. Where agency-published review and approval timeframes were not publicly available, a timeframe was not provided, and the column was noted as "N/A". Agency reviews may exceed published timelines.

[28] The estimated review duration provides an estimated range from typical to longest likely time for permit review and approval based on the consultants' experience with the applicable agencies and pipeline infrastructure permitting, as well as typical timeframes provided by SoCalGas's Land and Right-of-Way organization on previous projects (e.g., Pipeline Safety Enhancement Plan). Estimated review duration does not include time for completion of potential fieldwork, technical studies, or preparation of reports that may be needed to support SoCalGas's submission of the application for approval. Estimated timelines also assume some applications for approvals would overlap in time and could be prepared and processed concurrently with CEQA/NEPA timelines. See the Permit Dependencies and Notes column for permits requiring CEQA/NEPA completion prior to approval.

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months)[27]	Estimated Review Duration (months)[28]
			▫ Segment B may intersect in the city of Santa Clarita. Permits to impact the crossing in this area would likely be via an encroachment permit process with the city of Santa Clarita. ▫ Segment K may intersect in the city of Santa Clarita and unincorporated Los Angeles County. Permits to impact the crossings in these areas would likely be via an encroachment permit process with the administering jurisdiction. ▫ Segment L may intersect in unincorporated Kern. Permission to impact the crossings in this area would likely be acquired via the easement/TRE process. ▫ Segment M may intersect in unincorporated Kern County. Permits to impact crossings in this area would likely be via an encroachment permit process with Kern County. ▪ Pacific Crest Trail: ▫ Segment I may intersect in the San Bernardino National Forest, this crossing may be subject to 16 U.S.C. § 1248(a), as described below. ▫ Segment B may intersect in the unincorporated Community of Agua Dulce in Los Angeles County. The route crosses the trail within existing public ROW. Permits to impact this public ROW would be anticipated to be obtained from the Los Angeles County Department of Public Works ▫ Segment M may intersect in the unincorporated Kern County. Permission to impact the crossing in this area would likely be acquired via the easement/TRE process. Pursuant to 16 U.S.C. § 1248(a), the Secretary of the Interior or the Secretary of Agriculture may grant easements and ROW across components of the national trails system in accordance with the laws applicable to the National Park System and the National Forest System, respectively. However, given the location of the trails within paved roadways, a ROW grant is not anticipated to be required. Site-specific analysis may be required for each crossing to determine which agency holds jurisdiction, and whether pipeline crossings are permitted.			
State Historic Preservation Office (SHPO)	Cultural and/or historical resources	Section 106 National Historic Preservation Act Compliance	Required if there are potential impacts to cultural and/or historical resources that are listed or eligible for listing on the National Register of Historic Places. For potential pipeline segments that are located on BLM land, preparation of a Class III cultural resource inventory of the area of potential effect, including records search, intensive pedestrian survey, and technical report, may be required. Federal and CEQA lead agencies may conduct government-to-government consultation with Native American tribes and other individuals and organizations with knowledge of, or concerns with, historic properties in the areas surrounding the potential pipeline segments. If historic properties or cultural resources are identified, additional work such as testing, evaluation, data recovery, and archaeological monitoring may be warranted and consultation with SHPO may be required.	▪ The Section 106 process may occur concurrently with NEPA. ▪ If required, SHPO concurrence may occur prior to completion of NEPA. ▪ Consultation duration dependent on the number of tribal territories included in the consultation and potential negotiations regarding mitigation measures.	2	8-18

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months)[27]	Estimated Review Duration (months)[28]
USFS	USFS encroachment	Special Use Permit	Certain potential pipeline segments within the Collection Zone occur within Angeles National Forest and San Bernardino National Forest.	▪ NEPA must be complete prior to approval of SUP. ▪ Environmental permits may be required prior to approval of SUP.	N/A	12-18
USFWS	Federally listed species	ESA Section 7 Consultation Biological Opinion	A federal ESA Biological Opinion may be required from USFWS for any federally listed species where a federal nexus is present (e.g., BLM and USFS lands), per ESA Section 7. There is federally designated critical habitat for California condor, coastal California gnatcatcher, least Bell's vireo, southwestern willow flycatcher, arroyo toad, and San Bernardino Merriam's kangaroo rat near the potential pipeline routes in the Collection Zone. Additionally, the potential pipeline segments within the Collection Zone may be near habitat for many listed species for which critical habitat is designated (e.g., Mojave desert tortoise, San Joaquin kit fox, San Bernardino kangaroo rat, western yellow-billed cuckoo, Santa Ana sucker, western pond turtle, western spadefoot, vernal pool fairy shrimp, Bakersfield cactus, California Orcutt grass, Santa Ana River woollystar, Slender-horned spineflower, Delhi Sands flower-loving fly, Tipton kangaroo rat, Braunton's milk-vetch, Nevin's barberry). A CWA Section 404 Permit is anticipated to provide a federal nexus for aquatic and riparian species (e.g., arroyo toad, western pond turtle, western spadefoot, Santa Ana sucker, least Bell's vireo, southwestern willow flycatcher, western yellow-billed cuckoo).	▪ NEPA must be completed prior to the issuance of a Biological Opinion. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report to submit to USDWS can take 6-18 months to complete.	4.5	9-18
USACE	Waters of the U.S. (WOTUS)	Clean Water Act 404 Permit NWP 12	A CWA Section 404 Permit is required for any impacts to WOTUS, including jurisdictional wetlands, that involve the discharge of dredged or fill materials into a waterbody or wetland. NWP 12 provides coverage for the construction, maintenance, repair, and removal of pipelines and associated facilities in WOTUS, provided the activity does not result in the permanent loss of greater than ½ acre of WOTUS). New NEPA review is not required for NWP 12. A 401 Certification is also required; see State Water Resources Control Board and RWQCB below. The Antelope Valley watershed (northern portion of Segment B) contains no navigable WOTUS and 404 coverage would not be needed, but other potential pipeline segments may impact WOTUS and require 404 coverage.	▪ Section 7 consultation must be completed prior to the issuance of NWP 12.	3	6-9
State						
Lead agency for CEQA review	State discretionary action	EIR	There would be one lead agency for the Angeles Link Project. See comments, dependencies, and timeframes on Lead Agency for CEQA review in Appendix A			
CPUC	State discretionary action	CPCN or PTC	For a CPCN, the CPUC is required to certify the "public convenience and necessity" for a project before a utility may begin construction. A PTC is a comparatively streamlined process that also requires CPUC approval before construction of specific types of projects.	▪ The CPCN/PTC process concludes with the certification of the Final EIR and issuance of the CPCN or PTC.	29	23-49[29]

[29] In June 2023, Cal Advocates analyzed development timelines of 14 recently approved and completed electric transmission projects to understand potential development and permit review timelines. For larger projects (200 kV or more subject to the CPCN process), the average duration of the development process phases included 2.4 years of pre-application planning by the developer and 3.4 years of permitting by the CPUC. For smaller projects (50 KV to 200kV subject to the Permit to Construct process), the average duration development process phases included 4 years of pre-application planning by the developer and 2.3 years of permitting review by the CPUC. While the Cal Advocates analysis focused on electrical transmission projects, the analysis provides additional context for potential permitting timelines for new pipeline infrastructure. The Cal Advocates analysis is available at https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230612-caladvocates-transmission-development-timeline.pdf.

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months)[27]	Estimated Review Duration (months)[28]
Caltrans	State highway crossings	ROW Encroachment	Potential pipeline segments within the Collection Zone occur within Caltrans ROW.	▪ CEQA must be completed prior to permit issuance, and as a responsible agency, Caltrans could likely rely on the EIR. ▪ Caltrans may require evidence of inclusion in Regional HCPs if the proposed encroachment is within the boundary of an HCP.	3	6-12
CDFW	State protected species	CESA ITP	Required for take of state protected species, but cannot be issued for Fully Protected species such as the blunt-nosed leopard lizard, unarmored threespine stickleback, bald eagle, golden eagle, California condor, and white-tailed kite. Avoidance of blunt-nosed leopard lizard, unarmored threespine stickleback, bald eagle, golden eagle, California condor, and white-tailed kite habitat is recommended.	▪ CEQA must be completed prior to permit issuance, and as a responsible agency, CDFW could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete.	4	18-36
CDFW	Western Joshua tree	Western Joshua Tree Conservation Act ITP	Required authorization for take of Joshua tree, as well as trimming of live trees or removal of dead trees. The Act requires that the permittee must mitigate all impacts to, and taking of, the western Joshua tree but includes provisions that allow permittees to pay specified fees in lieu of conducting mitigation activities.	▪ CEQA must be completed prior to permit issuance, and as a responsible agency, CDFW could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-9 months to complete. ▪ Agency has 30 days to approve or deny permit application after confirming a complete application.	1	3-10
CDFW	Fully Protected species blunt-nosed leopard lizard, unarmored threespine stickleback, bald eagle, golden eagle, California condor, and white-tailed kite	Avoidance Plan	CDFW can potentially approve an Avoidance Plan for a fully protected species. An Avoidance Plan may include measures such as seasonal work and HDD activities to avoid impacts to a fully protected species. Based on survey results, CDFW may approve a BNLL Avoidance Plan; however, there are no specified timelines and CDFW is not required to approve.	▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete.	N/A	N/A
CDFW	Lake/streambed impacts	Section 1600 Lake or Streambed Alteration Agreement	Needed for impacts to CDFW jurisdictional drainages or drainage vegetation. Requires seasonal surveys. Likely a CEQA Responsible Agency.	▪ CEQA must be complete prior to permit issuance, and as a responsible agency, CDFW could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-9 months to complete.	3	6-9
CDFW	CDFW mitigation lands/preserves encroachment	SUP	Segment K may cross a CDFW-owned DWR mitigation area. Acquiring new or expanded ROW on mitigation lands could be difficult.	▪ Avoidance is recommended.	N/A based on avoidance	N/A based on avoidance
CEQA Lead Agency	Cultural and/or tribal resources	AB 52 Tribal Consultation	As part of the CEQA review, the lead agency would conduct government-to-government consultation pursuant to AB 52 (Public Resources Code § 21080.3.1 et seq.) The lead agency would consult with potentially impacted Native American tribes with knowledge of, or concerns with, cultural or tribal resources in the segment area. If cultural or tribal resources are identified, additional work such as testing, evaluation, data recovery, and archaeological monitoring may be warranted.	▪ The AB 52 consultation may occur concurrently with the CEQA review. ▪ Consultation duration dependent on the number of tribal territories included in the consultation and potential negotiations regarding mitigation measures. ▪ Duration would likely be consistent with estimated review duration for overall CEQA review.	N/A	23-49

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months)[27]	Estimated Review Duration (months)[28]
California Department of Water Resources	Aqueduct crossings	Encroachment Permit	Needed to perform work and install assets within State Water Project ROW.	▪ CEQA must be complete prior to permit issuance.	3	6-12
CSLC	CSLC encroachment	CSLC Lease	Segment M within the Collection Zone may traverse CSLC land. Likely a CEQA Responsible Agency.	▪ CEQA must be complete prior to permit issuance.	6-24	6-24
RWQCB	WOTUS/waters of the state	Individual 401 Certification and Waste Discharge Requirement	Two different permit types for impacts to waters of the state (WDR) and when coterminous with federal jurisdiction (401 Certification). The potential pipeline segments within the Collection Zone are within the Central Valley, Lahontan, Los Angeles, and Santa Ana RWQCBs. Depending on permitting approach and timing, it may be feasible for SoCalGas to pursue RWQCB permitting with the State Board rather than coordinating with multiple RWQCBs. The State Board may serve as a CEQA Responsible Agency.	▪ CEQA must be complete prior to permit issuance, and as a responsible agency, the RWQCB could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-9 months to complete.	12	12-24
State Parks	State Parks encroachment	SUP	Segments J may cross Chino Hills State Park, Segment K crosses Hungry Valley State Vehicular Recreation Area, and Segment Y near Rio de Los Angeles State Park Recreation Area. Public Resources Code §5012 authorizes, but does not require State Parks to grant, among other thing, permits and easements to public agencies for utilities and public roads and to grant other utility easement or to perform a public service, upon application by the proper authorities.	▪ CEQA must be complete prior to permit issuance.	N/A	12-18
Coastal Commission	Development in Coastal Zone	Coastal Development Permit	Segments within the Coastal Zone may require a Coastal Development Permit	▪ The Coastal Commission's regulatory program is a certified regulatory program and serves as the functional equivalent of CEQA review.	6	12-18
Regional: Local/Special District/Community Plan						
Special Districts	Special district encroachment	ROW Grant/Easement Acquisition	Potential pipeline segments within the Collection Zone may cross land under the ownership or jurisdiction of various special districts, including but not limited to flood control, water, irrigation, and recreation and conservation districts. ROW grants and/or easement acquisition from these districts may require Board approval and may trigger CEQA. Depending on the nature of the scope of activities within each district's jurisdiction, the special district may adopt a CEQA Categorical Exemption, or may take on a Responsible Agency role.	▪ CEQA must be complete prior to ROW grant/easement issuance. ▪ Each special district may impose individual conditions of approval.	Variable	Variable
Regional HCPs ▪ Kern County Valley Floor HCP (VFHCP) ▪ West Mojave Coordinated Management Plan Regional HCPs ▪ Western Riverside County Multiple Species HCP	Federally listed species	ESA Take authorization	Potential pipeline segments within the Collection zone are located within the VFHCP; however, the VFHCP is under development and is not anticipated to be adopted in the near future. Certain pipeline segments within the Collection Zone are within the West Mojave Plan (formerly West Mojave Coordinated Management Plan); however, the West Mojave Plan was invalidated in court and cannot be used. Certain pipeline segments within the Collection Zone are within the Western Riverside County Multiple Species HCP and may provide take authorization for several federally listed species. Certain potential pipeline segments within the Collection Zone may be located within the DRECP. Coordination with the administering agency would be necessary to determine if coverage through the DRECP Biological Opinion could be obtained.	▪ CEQA must be complete prior to issuance of Certificate of Inclusion by the Western Riverside County Multiple Species HCP, and Coachella Valley Multiple Species HCP ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete. ▪ Timeframe for coverage under the DRECP Biological Opinion is assumed to be the same as the BLM ROW Grant Easement process timeframe, as BLM is likely to process a DRECP Biological Opinion request concurrently with its overall approval for work under its jurisdiction.	N/A	12-18

Agency or Entity	Permit Trigger	Authorization / Evaluation	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Review Timeframe (months)[27]	Estimated Review Duration (months)[28]
Desert Renewable Energy Conservation Plan (DRECP)						
Unlikely Permit Pathways[30]						
USFWS	Federally protected species	ESA Section 10 HCP	A federal ESA take permit may be required from USFWS for any federally protected species when a federal nexus is absent in accordance with the Section 10 process. If no programmatic or SoCalGas specific HCP is adopted, a separate ESA take permit may be required from USFWS (i.e., San Joaquin kit fox, San Bernardino kangaroo rat, Tipton kangaroo rat, arroyo toad, western spadefoot, western pond turtle, coastal California gnatcatcher, least Bell's vireo, southwestern willow flycatcher, vernal pool fairy shrimp, Delhi Sands flower-loving fly, slender-horned spineflower, Nevin's barberry, Braunton's milk-vetch, Santa Ana River woollystar).	▪ NEPA must be completed prior to the issuance of the HCP. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete.	48-50	48-60
CDFW	Fully Protected species blunt-nosed leopard lizard, unarmored threespine stickleback, bald eagle, golden eagle, California condor, and white-tailed kite	NCCP	CDFW can potentially authorize take under an NCCP. An NCCP can cover multiple species. Based on approved NCCPs, these types of plans have not been approved on a project-by-project basis but rather for a given region.	▪ Development and adoption of an NCCP is estimated to be 8-9 years.	47[31]	Variable

[30] The permits identified under this heading were evaluated for applicability to the Project and were determined to be unlikely permitting pathways. The Project would likely fully avoid Fully Protected species and take authorization under an NCCP is not anticipated. SoCalGas assumes a federal nexus will allow for take authorization under Section 7 and authorization through Section 10 will not be required.

[31] Due to a limited number of NCCPs approved, the timeframe for approval of an NCCP was taken from the best case scenarios of a CDFW-published NCCP/HCP Process Flowchart and Normative Timelines graphic (available online at https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=109210&inline). This is based on seven NCCPs approved and permitted between 1996 and 2013.

Appendix C

Central Zone: Summary of Agencies, Permitting Role, and Agency Permitting Review Timeline for Potential Pipeline Segments within the Central Zone

Central Zone: Summary of Agencies, Permitting Role, and Agency Permitting Review Timeline for Potential Pipeline Segments within the Central Zone

Agency or Entity	Permit Trigger	Authorization	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Timeframes (months)[32]	Estimated Review Duration (months)[33]
Lead agency for NEPA review	Federal discretionary action	Environmental Impact Statement (EIS)	There would be one lead agency for the Angeles Link Project. See comments, dependencies, and timeframes on Lead Agency for NEPA review in Appendix A			
State Historic Preservation Office (SHPO)	Cultural and/or historical resources	Section 106 National Historic Preservation Act Compliance	Required if there are potential impacts to cultural and/or historical resources that are listed or eligible for listing on the National Register of Historic Places. For portions of the potential pipeline segments located on BLM land, preparation of a Class III cultural resource inventory of the area of potential effect, including records search, intensive pedestrian survey, and technical report, may be required. Federal and CEQA lead agencies may conduct government-to-government consultation with Native American tribes and other individuals and organizations with knowledge of, or concerns with, historic properties in the area surrounding the potential pipeline segments. If historic properties or cultural resources are identified, additional work such as testing, evaluation, data recovery, and archaeological monitoring may be warranted and consultation with SHPO may be required.	▪ The Section 106 process may occur concurrently with NEPA. ▪ If required, SHPO concurrence may occur prior to completion of NEPA. ▪ Consultation duration dependent on the number of tribal territories included in the consultation and potential negotiations regarding mitigation measures.	2	8-12
USFWS	Federally protected species	ESA Section 7 Consultation	A federal ESA Biological Opinion may be required from USFWS for any federally listed species (i.e., El Segundo blue butterfly, monarch butterfly, western pond turtle, western spadefoot). For purposes of this analysis, a federal nexus for the Project is assumed given the potential pipeline segments that would be constructed in the Connection, Collection, and Central Zones.	▪ NEPA must be completed prior to the approval of the Biological Opinion. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report to submit to USFWS can take 4.5-18 months to complete.	4.5	9-18
USACE	Waters of the U.S. (WOTUS)	Clean Water Act 404 Permit NWP 12	A CWA Section 404 Permit is required for any impacts to WOTUS, including jurisdictional wetlands, that involve the discharge of dredged or fill materials into a waterbody or wetland. NWP 12 provides coverage for the construction, maintenance, repair, and removal of pipelines and associated facilities in WOTUS, provided the activity does not result in the permanent loss of greater than ½ acre of WOTUS). New NEPA review is not required for NWP 12. A 401 Certification is also required; see State Water Resources Control Board and RWQCB below.	▪ Section 7 Consultation must be completed prior to the issuance of NWP 12.	3	6-9
State						
Lead agency for CEQA review	State discretionary action	EIR	There would be one lead agency for the Angeles Link Project. See comments, dependencies, and timeframes on Lead Agency for CEQA review in Appendix A			

[32] The regulatory/agency published timeframes provide timeframes for permit review and approval, as listed by the permitting agencies through publicly available resources. Where agency-published review and approval timeframes were not publicly available, a timeframe was not provided, and the column was noted as "N/A". Agency reviews may exceed published timelines.

[33] The estimated review duration provides an estimated range from typical to longest likely time for permit review and approval based on the consultants' experience with the applicable agencies and pipeline infrastructure permitting, as well as typical timeframes provided by SoCalGas's Land and Right-of-Way organization on previous projects (e.g., Pipeline Safety Enhancement Plan). Estimated review duration does not include time for completion of potential fieldwork, technical studies, or preparation of reports that may be needed to support SoCalGas's submission of the application for approval. Estimated timelines also assume some applications for approvals would overlap in time and could be prepared and processed concurrently with CEQA/NEPA timelines. See the Permit Dependencies and Notes column for permits requiring CEQA/NEPA completion prior to approval.

Agency or Entity	Permit Trigger	Authorization	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Timeframes (months)[32]	Estimated Review Duration (months)[33]
CPUC	State discretionary action	CPCN or PTC	For a CPCN, the CPUC is required to certify the "public convenience and necessity" for a project before a utility may begin construction. A PTC is a comparatively streamlined process that also requires CPUC approval before construction of specific types of projects. The state lead agency is anticipated to be the CPUC.	▪ The CPCN/PTC process concludes with the certification of the Final EIR and issuance of the CPCN or PTC.	29	23-49[34]
Caltrans	State highway crossings	ROW Encroachment	Potential pipeline segments within the Central Zone occur within Caltrans ROW.	▪ CEQA must be completed prior to permit issuance, and as a responsible agency, Caltrans could likely rely on the EIR. ▪ Caltrans may require evidence of inclusion in Regional HCP's if the proposed encroachment is within the boundary of an HCP.	3	6-12
CDFW	State protected species	CESA ITP	Required for take of state protected species (i.e., tricolored blackbird).	▪ CEQA must be completed prior to permit issuance, and as a responsible agency, CDFW could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete. ▪ Agency review and approval can take 4-36 months.	4	18-36
CDFW	Lake/streambed impacts	Section 1600 Lake or Streambed Alteration Agreement	Needed for impacts to CDFW jurisdictional drainages or drainage vegetation. Requires seasonal surveys. Likely a CEQA Responsible Agency.	▪ CEQA must be complete prior to permit issuance, and as a responsible agency, CDFW could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-9 months to complete.	3	6-9
CEQA Lead Agency	Cultural and/or tribal resources	AB 52 Tribal Consultation	As part of the CEQA review, the lead agency would conduct government-to-government consultation pursuant to AB 52 (Public Resources Code § 21080.3.1 et seq.) The lead agency would consult with potentially impacted Native American tribes with knowledge of, or concerns with, cultural or tribal resources in the segment area. If cultural or tribal resources are identified, additional work such as testing, evaluation, data recovery, and archaeological monitoring may be warranted.	▪ The AB 52 consultation may occur concurrently with the CEQA review. ▪ Consultation duration dependent on the number of tribal territories included in the consultation and potential negotiations regarding mitigation measures. ▪ Duration would likely be consistent with estimated review duration for overall CEQA review.	N/A	23-49
RWQCB	WOTUS/waters of the state	Individual 401 Certification and Waste Discharge Requirement	Two different permit types for impacts to waters of the state (WDR) and when coterminous with federal jurisdiction (401 Certification). Pipeline segments within the Central Zone are within the Los Angeles RWQCB. The Los Angeles RWQCB could be a CEQA Responsible Agency.	▪ CEQA must be complete prior to permit issuance, and as a responsible agency, the RWQCB could likely rely on the EIR. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-9 months to complete.	12	12-24
Regional: Local/Special Districts						
Special Districts	Special district encroachment	ROW Grant/Easement Acquisition	Pipelines within the Central Zone may cross land under the ownership or jurisdiction of various special districts, including flood districts and joint power authorities. ROW grants and/or easement acquisition from these districts may require Board approval and may trigger CEQA. Depending on the nature of the scope of construction activities within each district's jurisdiction, the special district may adopt a CEQA Categorical Exemption, or may take on a Responsible Agency role.	▪ CEQA must be complete prior to ROW grant/easement issuance. ▪ Each special district may impose individual conditions of approval.	Variable	Variable

[34] In June 2023, Cal Advocates analyzed development timelines of 14 recently approved and completed electric transmission projects to understand potential development and permit review timelines. For larger projects (200 kV or more subject to the CPCN process), the average duration of the development process phases included 2.4 years of pre-application planning by the developer and 3.4 years of permitting by the CPUC. For smaller projects (50 KV to 200kV subject to the Permit to Construct process), the average duration development process phases included 4 years of pre-application planning by the developer and 2.3 years of permitting review by the CPUC. While the Cal Advocates analysis focused on electrical transmission projects, the analysis provides additional context for potential permitting timelines for new pipeline infrastructure. The Cal Advocates analysis is available at https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230612-caladvocates-transmission-development-timeline.pdf.

Agency or Entity	Permit Trigger	Authorization	Comments	Permit Dependencies and Notes	Regulatory / Agency Published Timeframes (months)[32]	Estimated Review Duration (months)[33]
Unlikely Permit Pathways[35]						
USFWS	Federally protected species	ESA Section 10 HCP	A federal ESA take permit may be required from USFWS for any federally protected species when a federal nexus is absent in accordance with the Section 10 process. If no programmatic or SoCalGas specific HCP is adopted, a separate ESA take permit may be required from USFWS (i.e., El Segundo blue butterfly, monarch butterfly, western pond turtle, western spadefoot).	▪ NEPA must be completed prior to the issuance of the HCP. ▪ Completion of the necessary fieldwork, technical studies, and preparation of the report can take 6-18 months to complete.	48-50	48-60

[35] The permits identified under this heading were evaluated for applicability to the Project and were determined to be unlikely permitting pathways. SoCalGas assumes a federal nexus will allow for take authorization under Section 7 and authorization through Section 10 will not be required.

July 2024

ANGELES LINK PROJECT OPTIONS & ALTERNATIVES REPORT DRAFT

SoCalGas commissioned this study from Wood Mackenzie. The analysis was conducted, and this report was prepared, collaboratively.

Table of Contents

0. Acronyms, Glossary, Tables & Figures

0.1. Acronyms and Abbreviations

ALMA	Angeles Link Memorandum Account
AQMD	Air Quality Management District
ARCHES	Alliance for Renewable Clean Hydrogen Energy Systems
BAU	Business as Usual
BCF	Billion Cubic Feet
BESS	Battery Energy Storage Systems
BEV	Battery Electric Vehicle
CARB	California Air Resources Board
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CapEx	Capital Expenditure
CBOSG	Community Based Organization Stakeholder Group
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CO_2	Carbon Dioxide
DOE	Department of Energy
GHG	Greenhouse Gases
FCEB	Fuel Cell Electric Bus
FCEV	Fuel Cell Electric Vehicle
GW	Gigawatt
IEA	International Energy Agency
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act
HDV	Heavy-Duty Vehicle
LADWP	Los Angeles Department of Water & Power
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Delivered Hydrogen
LDES	Long Duration Energy Storage
LDV	Light-Duty Vehicle
MDV	Medium-Duty Vehicle
MTPA/MMT	Million Tonnes per Annum
NEPA	National Environmental Policy Act
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturers
OpEx	Operating Expenses
PAG	Planning Advisory Group
PPA	Power Purchase Agreement
PTC	Production Tax Credit
RNG	Renewable Natural Gas
PSIG	Per Square Inch Gauge
SC	Scheduling Coordinator
SoCalGas	Southern California Gas Company
SJV	San Joaquin Valley
SMR	Steam Methane Reformers
T&D	Transmission and Distribution
VRFB	Vanadium Redox Flow Batteries
ZEV	Zero-emission Vehicle

0.2. Glossary of Terms

The following terms are used in this report. For the purposes of this report, the terms are used as follows:

Carbon capture and sequestration (CCS) – A set of technologies that remove CO_2 either from the atmosphere or from point sources. The captured CO_2 is then compressed and injected into deep underground geological formations (that may include depleted oil and gas reservoirs or saline formations) for permanent storage.[1] For purposes of this report, CCS alternatives are those that include the removal of CO_2 from point sources and permanent sequestration (not for use in oil and gas recovery).

Clean firm power - Zero-carbon power generation sources that can be relied on whenever and for as long as needed. Clean firm power sources do not depend on the weather like solar and wind do, and do not have limitations in duration of power production capabilities (as long as fuel is available).[2]

Clean renewable hydrogen – For purposes of Angeles Link Phase 1 studies, clean renewable hydrogen refers to hydrogen that is produced through a process that results in a lifecycle (i.e., well-to-gate) greenhouse gas (GHG) emissions rate of not greater than four kilograms of carbon dioxide-equivalent per kilogram of hydrogen produced and does not use any fossil fuel in its production process.[3]

Cogeneration – Combined heat and power (CHP), also referred to as cogeneration, is the simultaneous generation of useful heat and electricity from a single fuel source.[4]

Dispatchable energy/dispatchable generation – Resources that are classified as dispatchable by the scheduling coordinator (SC) or the California Independent System Operator (CAISO) and could include a variety of technologies: steam turbines; combustion turbines; combined cycle gas turbines; reciprocating engines; energy storage; dispatchable CHP; biomass and geothermal resources.[5]

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[1] SCALE Act, Senate Bill 799.
[2] SB100 Clean Firm Power Report Plus SI, p. 5.
[3] As defined in CPUC Decision (D.) 22-12-055.
[4] CPUC Combined Heat and Power (CHP) Program Overview.
[5] CPUC 2020 Qualifying Capacity Methodology Manual.

Electrification – Electrification refers to a combination of system level[6] transformation and use case level[7] technology changes including the grid infrastructure required to support growing electric load. The purpose of electrification in California is to reduce GHG emissions in carbon-intensive demand sectors by powering these sectors with electricity produced using zero-carbon technologies over time.[8]

Electrolyzer – Electrolysis is the process of using electricity to split water into hydrogen and oxygen. This reaction takes place in a unit called an electrolyzer.[9]

Energy density – The amount of energy that can be stored per unit of volume or mass; higher energy density means more energy can be stored in a smaller volume or mass.[10]

***Levelized Cost of Electricity* (*LCOE*) –** Represents the average revenue per unit of electricity generated that would be required to recover the return on capital related to costs of building and operating a generating plant. LCOE is a summary metric to measure of the overall competitiveness of different generating technologies.[11]

Linepack – Gas linepack refers to the gas stored in gas pipelines due to the compressibility of the gas. As a form of gas energy storage, linepack can enhance system flexibility.[12]

Long-duration energy storage (LDES) – A portfolio of technologies that store energy over long periods for future dispatch and marked by duration of dispatch (e.g., multi-day and seasonal).[13]

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[6] System level electrification includes the incremental electricity generation, storage, and supporting upstream grid infrastructure requirements to meet wide-scale end use electrification needs.
[7] Use-case level electrification refers to replacing technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically powered equivalents, such as electric vehicles or heat pumps. More details at IEA Electrification Overview.
[8] California Air Resources Board, 2022 Scoping Plan Documents.
[9] Hydrogen Production: Electrolysis, DOE Office of Energy Efficiency & Renewable Energy.
[10] Department of Energy Vehicle Technology Office definition, available at FOTW #1234, April 18, 2022: Volumetric Energy Density of Lithium-ion Batteries Increased by More than Eight Times Between 2008 and 2020 | Department of Energy.
[11] As defined in EIA Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022.
[12] As defined in Optimal scheduling of hydrogen blended integrated electricity–gas system considering gas linepack via a sequential second-order cone programming methodology. Wu et al.
[13] DOE Pathway to: Long Duration Energy Storage Commercial LiftOff.

Levelized Cost of Delivered Hydrogen (LCOH) – Reflects the unit cost of hydrogen based on the return on capital related to the cost of production, transmission, storage, and distribution. When used in this study, LCOH refers to the delivered cost of hydrogen.

Reliability and resiliency – Reliability refers to a system having sufficient resources to adequately meet demand while accounting for commonly-expected events (e.g., equipment failure, short-duration outages). Resilience focuses on the ability of a system to withstand/recover from high-impact, low-frequency events that are often unexpected and can result in long duration outages.[14]

Renewable energy – Renewable energy uses energy sources that are continually replenished by nature — the sun, the wind, water, the Earth's heat, and plants. Renewable energy technologies turn these fuels into usable forms of energy—most often electricity, but also heat, chemicals, or mechanical power.[15]

Renewable natural gas (RNG) – Also known as "biomethane," RNG is a combustible gas produced from the anaerobic decomposition of organic materials (i.e., biogas) that is captured and then purified to a quality suitable for injection into a gas pipeline. Major sources of biomethane include non-hazardous landfills, wastewater treatment facilities, organic waste, and animal manure. The California Public Utilities Commission (CPUC) has recognized that "biomethane can capture methane emissions from the waste sector and be used as a direct replacement for fossil natural gas to help California reduce its GHG emissions."[16]

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[14] CPUC Microgrids Proceeding 2.19-09-009: Resiliency Standards: Definitions and Metrics.
[15] Per NREL's Renewable Energy: An Overview report for the Department of Energy.
[16] More details on definition available at CPUC Renewable Gas.

0.3. List of Figures

0.4. List of Tables

1. Executive Summary

1.1. Project Options & Alternatives Study Overview

Southern California Gas Company (SoCalGas) proposes to develop a hydrogen pipeline system (Angeles Link) to transport clean renewable hydrogen[17] from regional third-party production sources and storage sites to end users in Central and Southern California, including in the Los Angeles Basin (L.A. Basin). The Angeles Link pipeline system is anticipated to extend across approximately 450 miles.

Angeles Link is intended to support California's decarbonization goals[18] through the significant reduction of greenhouse gas (GHG) emissions in hard-to-electrify sectors of the economy, including dispatchable power generation, mobility[19] and industrial sectors. Additionally, Angeles Link seeks to enhance energy system reliability and resiliency and enable the development of third-party long duration energy storage (LDES) resources, as California works to achieve the State's decarbonization goals.

On December 15, 2022, the California Public Utilities Commission (CPUC) approved Decision (D.) 22-12-055, which authorized SoCalGas to establish the Angeles Link Memorandum Account (ALMA) to track expenses related to conducting Phase 1 feasibility studies.[20] The Project Options & Alternatives Study (hereafter referred to as the Alternatives Study)[21] was prepared pursuant to D.22-12-055, Ordering Paragraph (OP) 6 (d), which required SoCalGas to consider and evaluate project alternatives, including a localized hydrogen hub and electrification. As described in more detail in Step 6 below, the Alternatives Study incorporates findings from the High-Level Economic Analysis & Cost Effectiveness Study (Cost Effectiveness Study) and Environmental Analysis.

Input and feedback from stakeholders, including the Planning Advisory Group (PAG) and Community Based Organization Stakeholder Group (CBOSG), was helpful in the development of this study. For example, in response to stakeholder input, the study clarifies that both electrification and localized hub alternatives were included and evaluated as described in later sections in compliance with D.22-12-055.

[17] As defined in D.22-12-055.
[18] For example, see California Air Resources Board's (CARB) 2022 Scoping Plan for Achieving Carbon Neutrality, at pp. 9-10, and Senate Bill 100 (SB 100).
[19] Governor's Executive Order N-79-20, also CARB's Advanced Clean Fleets and Truck regulations.
[20] D.22-12-055.
[21] Project options refer to various routing scenarios as described in the Pipeline Sizing and Design Criteria Study. The Alternatives Study integrates those options as part of the overall evaluation of Angeles Link and alternatives.

Additionally, the Alternatives Study has expanded discussion around the selection and assessment criteria used to evaluate alternatives in this report. Section 6 below provides additional details on stakeholder comments and responses received as of the writing of this draft report. All feedback received is included, in its original form, in the quarterly reports submitted to the CPUC and published on SoCalGas' website.[22]

1.2. Study Approach

The Alternatives Study used a six-step evaluation framework to identify and assess potential alternatives to Angeles Link as described below. The methodology and interim results of each step are detailed throughout this study.

- Step 1: Identify potential alternatives.
- Step 2: Evaluate potential alternatives against identified criteria.
- Step 3: Dismiss alternatives that fail to satisfy Step 2 criteria.
- Step 4: Select alternatives to carry forward for further analysis.
- Step 5: Provide alternatives to cost effectiveness and environmental studies.
- Step 6: Incorporate findings from the Cost Effectiveness Study and Environmental Analysis and evaluate each alternatives' fulfilment of the purpose and need for Angeles Link.[23]

The Alternatives Study aimed to evaluate Angeles Link and alternatives across a specific set of objectives as identified below:

Hydrogen Delivery Alternatives: *How does Angeles Link compare to alternative methods for delivering clean renewable hydrogen to end users in the region across mobility, power, and industrial sectors?*

Non-Hydrogen Alternatives: *How does clean renewable hydrogen delivered by Angeles Link compare to alternative, non-hydrogen decarbonization pathways for key use cases across mobility, power, and industrial sectors?*

Given these objectives, alternatives were evaluated across two categories—Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives. As mentioned previously, the portfolio of potential

[22] Angeles Link: Shaping the Future with Clean Renewable Hydrogen
[23] See Section 3.2 for additional detail on the Purpose and Need for Angeles Link.

alternatives identified for this study (see Table 1) considered the various stakeholder comments received from the PAG and CBOSG.

Table 1: Portfolio of Potential Alternatives Identified for Evaluation

Category	Selected for Consideration in Step 2	Not Selected for Consideration in Step 2[24]
Potential Hydrogen Delivery Alternatives	• Localized hub • Power transmission & distribution (T&D) with in-basin hydrogen production • Liquid hydrogen trucking • Gaseous hydrogen trucking • Liquid hydrogen shipping • Methanol shipping • Ammonia shipping[25] • Intermodal transport (liquid hydrogen trucking and liquid hydrogen rail)[26]	• No alternative was excluded
Potential Non-Hydrogen Alternatives	• Electrification • Carbon Capture & Storage (CCS)	• Renewable Natural Gas (RNG) • Energy efficiency • Nuclear power generation • Hydro power generation • Geothermal power generation • Plug-in hybrid vehicles • Biofuel vehicles • Ethanol vehicles

Each of the alternatives explored has the potential to play a role as a complementary solution within a broader portfolio of technologies deployed to address California's decarbonization goals. However, for the purposes of this study, each alternative is addressed on a standalone basis. This approach was taken to evaluate each alternative's ability to meet the purpose and need for Angeles Link. Alternatives that could not meet the equivalent energy demand serviced by Angeles Link or could not meet the defined set of scoring criteria were not carried forward for further evaluation in Step 2. Angeles Link and the selected portfolio of alternatives that moved to Step 2 (of the six-step evaluation framework) were

[24] These other clean fuels and technologies were considered in Step 1 but screened out for further evaluation. See Section 4.2 for details on the rationale.
[25] Ammonia shipping and intermodal transport (liquid hydrogen trucking and liquid hydrogen rail) were evaluated in Step 3 (of the six-step process as discussed above) but not selected for further analysis in the Cost Effectiveness Study or Environmental Analysis. See Appendix 7.3 for more details.
[26] Ibid.

assessed against a set of identified criteria based on the type of alternative as shown in Table 2 and Table 3 below.

Table 2: Criteria Used to Assess Hydrogen Delivery Alternatives[27]

Hydrogen Delivery Alternatives	Assessment Criteria				
1. Localized hub 2. Power transmission & distribution (T&D) with in-basin hydrogen production 3. Liquid hydrogen trucking 4. Gaseous hydrogen trucking 5. Liquid hydrogen shipping 6. Methanol shipping 7. Ammonia shipping 8. Intermodal transport[28]	State Policy	Range	Reliability & Resiliency	Ease of Implementation	Scalability

Table 3: Criteria Used to Assess Non-Hydrogen Alternatives

Non-Hydrogen Alternatives	Assessment Criteria				
1. Electrification 2. CCS	State Policy	Tech. Maturity	Reliability & Resiliency	End User Requirements	Scalability

1.3. Key Findings

The evaluation of Angeles Link compared to Hydrogen Delivery Alternatives found that Angeles Link is the best suited option to meet the evaluation criteria for the delivery of clean renewable hydrogen at scale across Central and Southern California, including the L.A. Basin. As estimated in the Demand Study, and as discussed further in Section 4.3.2, Angeles Link has the potential to serve the heavy-duty transportation, clean dispatchable power generation, and hard-to-electrify industrial sectors at scale in support of California's decarbonization objectives. Other alternatives, such as a localized hub or hydrogen trucking, could serve as partial decarbonization solutions; however, neither of these alternatives has the ability to meet the throughput volumes, transport distances, or cost-effectiveness[29] of a pipeline system at the scale needed to meet California's decarbonization targets. Similarly, while shipping alternatives such as liquid hydrogen and methanol can be used for long-distance transportation

[27] See Section 4.3 for definitions of criteria and the methodology used to assess alternatives.
[28] Intermodal transport includes a combination of Liquid Hydrogen Trucking and Liquid Rail transportation.
[29] See Angeles Link Cost Effectiveness Study for additional information.

of hydrogen at scale, they are not suitable for transporting intrastate hydrogen production throughout Central and Southern California, including the L.A. Basin. Finally, power transmission and distribution with in-basin hydrogen production would require more extensive and complex infrastructure development compared to pipelines. The transmission of enough power to produce 1.5 Mtpa[30,31] of hydrogen could require the development of more than twenty high-capacity electric transmission circuits[32] that are less cost-effective,[33] more challenging to implement, [34] and less reliable and resilient[35] than an underground pipeline system.

The evaluation of Angeles Link compared to Non-Hydrogen Alternatives found Angeles Link is best suited to meet the operational requirements of long-haul, high payload, high duty-cycle vehicles such as long-range trucks and buses when compared to electrification. Carbon capture and sequestration (CCS) is not a technically viable alternative that could be deployed at scale to capture tailpipe emissions for the mobility sector. In the dispatchable power sector, hydrogen meets the criteria to serve as a source of clean firm generation and LDES. While battery storage as a standalone solution is mature and can be deployed at scale, it is cost-prohibitive to overbuild for system reliability needs without advances in other LDES technologies. Additionally, in several industrial subsectors, industrial retail electricity tariffs in California would make the cost of hydrogen supplied by Angeles Link competitive with electrification, especially for higher heat industrial applications.

The evaluation also showed that CCS could offer a cost-effective pathway for the decarbonization of certain industrial sectors such as cement.[36] However, CCS may face challenges in terms of maturity,

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30 The acronym Million Tonnes Per Annum (Mtpa) or Million Metric Tonnes (MMT) is used interchangeably across multiple Angeles Link studies.
31 1.5 Mtpa refers to Scenario 7 Preferred Configuration A (Scenario 7) in the Design Study.
32 A circuit refers to a specialized cable that carries power from one location to another. A transmission line can be defined as single or double circuit, depending on the number of circuits. The number of circuits and lines required depends on the power generation capacity and carrying capacity for the distance from supply to sub-station. A 500kV AC transmission system was selected in order to meet the capacity requirements for the Delivery Alternative. The 500kV system is largely compatible with the CAISO grid, which is mostly AC. 26.6 GW is the electricity need for the electrolysis process. Total generation also accounts for transmission losses of 1.8 GW for the scope configuration of Scenario 7 of the in-basin hydrogen production with power T&D alternative. Total installed solar capacity is estimated at 43 GW in the Production Study to account for intra-day availability. Refer to the Cost Effectiveness Study Appendix 7.2.2 and 7.3.1 for additional details.
33 See Angeles Link Cost Effectiveness Study for additional information.
34 Transmission Project Development Timelines in California.
35 Public Safety Power Shutoffs (ca.gov).
36 SB 596 requires CARB to develop a comprehensive strategy for the cement industry to achieve net-zero emissions by 2045, see: Net-Zero Emissions Strategy for the Cement Sector.

scalability, and the ability to meet end-user requirements[37] in power and other industrial sectors. The adoption of CCS for capturing CO_2 is highly site, sector, and location specific, and will therefore require the consideration of site, sector, and regional factors beyond the scope of this study, including access to CO_2 transport and sequestration infrastructure near point sources. Proximity and access to CO_2 transport and sequestration infrastructure is crucial to the development of CCS projects, particularly for point sources that do not have the scale to support integrated infrastructure development on their own.

The California Air Resources Board's (CARB) 2022 Scoping Plan identified clean renewable hydrogen as key to achieving California's decarbonization objectives, particularly in hard-to-electrify sectors of the economy. [38] Angeles Link is intended to support the CARB's Scoping Plan and California's decarbonization goals through the delivery of clean renewable hydrogen to serve consumers in hard-to-electrify sectors. The evaluation of Angeles Link and potential alternatives for the delivery of clean renewable hydrogen at scale across Central and Southern California, including the L.A. Basin, identified Angeles Link as the best suited option for achieving the criteria identified in this study. Angeles Link also performed well with respect to the criteria defined for the evaluation of Non-Hydrogen Alternatives and is well positioned to serve hard-to-electrify industrial consumers, dispatchable electric generation, and heavy-duty transportation in Central and Southern California.

[37] Refer to the definition of criteria in Table 10.
[38] See California Air Resources Board's (CARB) 2022 Scoping Plan for Achieving Carbon Neutrality, at pp. 9-10, and Senate Bill 100 (SB 100).

2. Study Background

2.1. Purpose and Objectives of Study

The Alternatives Study identifies potential alternatives to Angeles Link, establishes criteria to evaluate the alternatives, performs an assessment of Angeles Link and alternatives against these criteria, and performs a summary evaluation for Phase 1 purposes of Angeles Link and alternatives against the purpose and need for Angeles Link (described in Sections 3.2 and 4.4.3). Alternatives were grouped into two categories:

- **Hydrogen Delivery Alternatives** address the question: "How does Angeles Link compare to alternative configurations for producing and delivering clean renewable hydrogen to end users in the region?" These alternatives include various other hydrogen production configurations and modes of transportation, such as a localized hydrogen hub, trucking, shipping, and in-basin production supported by out-of-basin renewable electricity and power transmission and distribution (T&D) infrastructure.
- **Non-Hydrogen Alternatives** address the question: "How does Angeles Link compare to alternative, non-hydrogen decarbonization pathways for key use cases across power, mobility, and industrial sectors?" These alternatives include various non-hydrogen decarbonization pathways and technologies, including electrification and CCS.

The criteria for assessing alternatives were defined in consideration of the need for Angeles Link. The Alternatives Study evaluated each alternative with respect to the defined criteria, including compatibility with state policy, technological maturity, range of deliverability, reliability and resiliency, ease of implementation, end user requirements, and scalability. The criteria also included cost, which was evaluated in the Cost Effectiveness Study, and high-level environmental impacts, which were evaluated in the Environmental Analysis. The main output of this evaluation was a high-level summary of the relative strengths and weaknesses of alternatives across the identified criteria.

2.2. Relationship with Other Studies

The Alternatives Study both informed and was informed by other Angeles Link Phase 1 studies as follows:

- The Production Study provided the potential hydrogen production regions and the associated production and storage costs to inform the delivery capacity required of potential Hydrogen Delivery Alternatives.
- The Pipeline Routing/Sizing & Design Study informed the Angeles Link routing, sizing, and design criteria, and Angeles Link system costs to enable the selection and definition of potential Hydrogen Delivery Alternatives based on relatively consistent sizing and geographic considerations.
- The Demand Study provided information on the total addressable market and relevant use cases for hydrogen across mobility, power, and industrial sectors, which informed the use cases selected for analysis of Non-Hydrogen Alternatives.
- The Cost Effectiveness Study evaluated the alternatives identified in this study and performed cost analysis, the high-level results of which have been incorporated into this study.
- The Environmental Analysis evaluated the potential environmental impacts associated with Angeles Link and the Hydrogen Delivery Alternatives and Non-Hydrogen Delivery identified in this study.

3. Description of Angeles Link

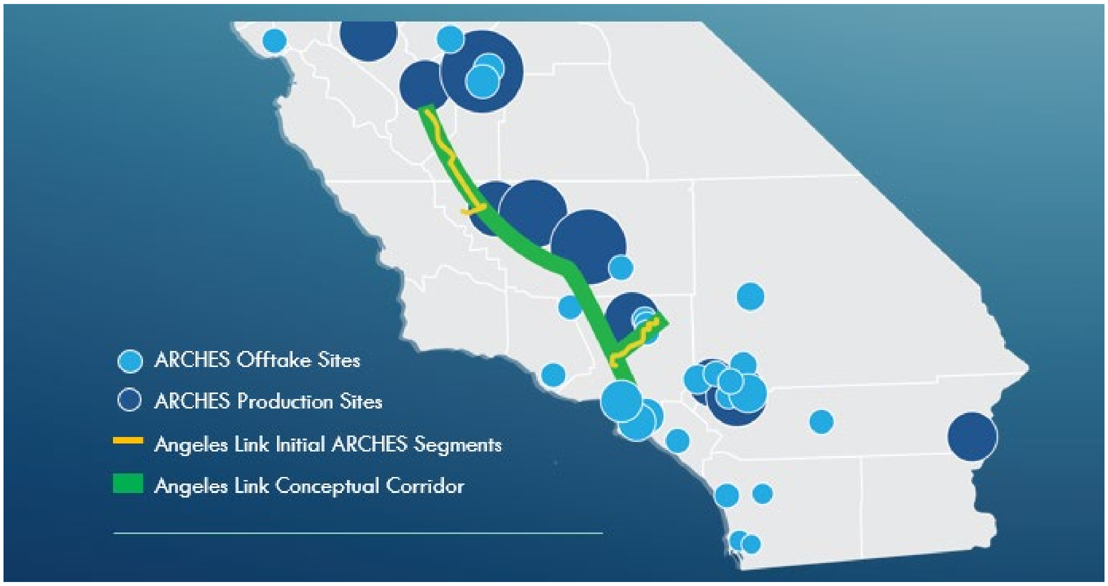
This section provides a high-level description of Angeles Link and its stated purpose and need to enable a comparison of Angeles Link to the identified alternatives.

3.1. Project Description

Angeles Link is proposed to include the following characteristics:

- A non-discriminatory pipeline system that is dedicated to public use.
- Transports clean renewable hydrogen from regional third-party production and storage sites to end users in Central and Southern California, including the L.A. Basin (inclusive of the Ports of Los Angeles and Long Beach).
- Extends across approximately 450 miles.
- Includes two pipeline segments (San Joaquin Valley, or SJV, and Lancaster) within the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES).[39]
- Ranges from approximately 200 to 1200 pounds per square inch gauge (psig).
- Has pipeline diameter(s) that may be up to 36 inches.
- Routed to maximize use of existing rights-of-way, as feasible.
- Sized for an annual total throughput of approximately 0.5 to 1.5MMT over time.
- May be constructed in stages.

Figure 1: Illustrative Map of Angeles Link Infrastructure[40]



[39] Meet-Arches_October-2023.pdf (archesh2.org).
[40] Ibid, Illustrative map of the ARCHES hydrogen hub.

3.2. Purpose and Need for Angeles Link

Angeles Link is intended to fulfill several underlying purposes, including the following:

1. To support California's decarbonization goals, including CARB's 2022 Scoping Plan for Achieving Net Neutrality, which identifies the scaling up of renewable hydrogen for the decarbonization of hard-to-electrify sectors as playing a key role in the State achieving carbon neutrality by 2045 or earlier.[41]
2. To support California's decarbonization goals in the mobility sector, including the Governor's Executive Order N-79-202,[42] which seeks to accelerate the deployment of zero-emission vehicles; CARB's implementation of the Advanced Clean Fleets regulation, which is a strategy to deploy medium- and heavy-duty zero-emission vehicles;[43] as well as the implementation of the March 15, 2021 Advanced Clean Truck regulation,[44] which aims to accelerate a large-scale transition of zero-emission medium-and heavy-duty vehicles.
3. To optimize service to all potential end users in the project area by operating an open access, common carrier clean renewable hydrogen transportation system dedicated to public use.
4. To support improving California's air quality by displacing fossil fuels for certain hard-to-electrify sectors, including the mobility sector.
5. To enhance energy system reliability, resiliency, and flexibility as California industries transition fuel usage to achieve the State's decarbonization goals.
6. To enable long duration clean energy storage that can further accelerate renewable energy development, minimize grid curtailments, and enhance energy system resiliency.
7. To provide a cost effective, transparent, and affordable open access clean renewable hydrogen transportation system at just and reasonable rates.
8. To provide efficient and safe clean renewable energy transportation in support of the State's decarbonization goals.

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[41] California Air Resources Board's 2022 Scoping Plan for Achieving Carbon Neutrality, at pp. 9-10, available at 2022 Scoping Plan for Achieving Carbon Neutrality.
[42] Governor's Executive Order N-79-202.
[43] Advanced Clean Fleets Regulation Summary: California Air Resources Board.
[44] Advanced Clean Trucks Regulation: California Air Resources Board.

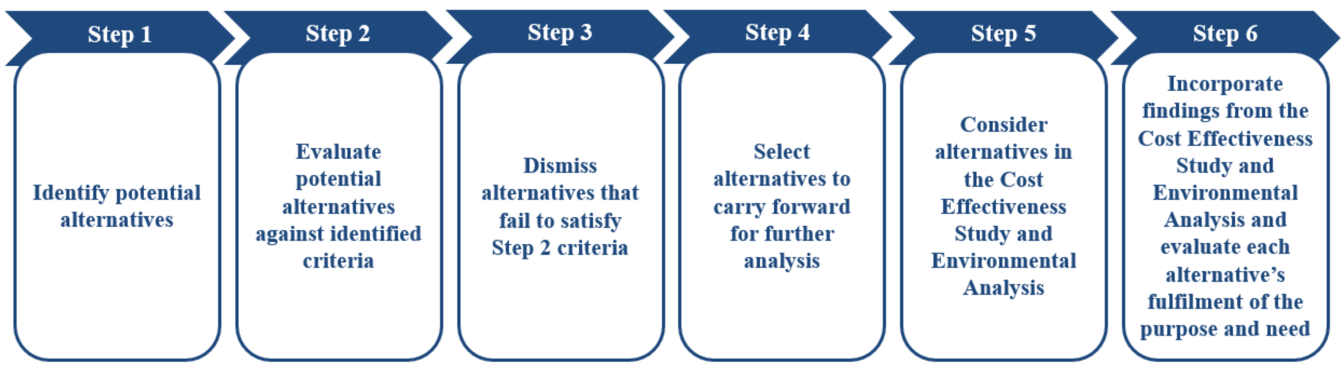
9. Over time and combined with other current and future clean energy projects and reliability efforts, to help reduce natural gas use served by the Aliso Canyon natural gas storage facility while continuing to provide reliable and affordable energy service to the region.

4. Framework for Evaluation of Project Alternatives

4.1. Overview of the Six-Step Evaluation Process

The Alternatives Study followed six-steps to assess Angeles Link and its alternatives and efficiently integrate findings from other relevant studies. These six-steps informed the study's methodology and are reflected in the structure of this report.

Figure 2: Overview of Six-Step Evaluation Process



Step 1: Identify potential alternatives.

At the onset of the Alternatives Study, a portfolio of potential alternatives was identified, including the specific alternatives identified in D.22-12-055 (localized hub and electrification).[45] The initial portfolio of potential alternatives was developed and pre-screened based on the technical requirements provided in the Decision (e.g., clean renewable hydrogen production), geographic alignment with ARCHES for hydrogen infrastructure development within California, and a high-level alignment with the purpose and need for Angeles Link.

A screening list of potential alternatives (see Table 4 below) was grouped into two categories: Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives.

- **Hydrogen Delivery Alternatives** comprised various alternative clean renewable hydrogen modes of transportation, in addition to the localized hydrogen hub alternative.[46] This included power T&D with in-basin hydrogen production, liquid hydrogen trucking, gaseous hydrogen

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[45] D.22-12-055.
[46] See Appendix 7.1.1 for additional information on the localized hub.

trucking, liquid hydrogen shipping, methanol and ammonia shipping (as hydrogen derivates), and intermodal transport (liquid hydrogen trucking and liquid hydrogen rail). All alternatives were selected for further evaluation in Step 2.

- **Non-Hydrogen Alternatives** were defined to address specific use cases within the priority sectors identified in the Demand Study across the mobility, power, and industrial sectors (e.g., within the mobility sector, battery electric vehicles (BEV) for the heavy-duty, long-haul trucking use case). Non-Hydrogen Alternatives comprised alternative decarbonization technologies, including electrification[47,48] and CCS. Other potential alternatives not selected for further evaluation in Step 2 (of the six-step evaluation framework) include renewable natural gas (RNG), energy efficiency, nuclear power generation, hydro power generation, geothermal power generation, plug-in hybrid vehicles, bio-fuels, and ethanol vehicles. See Section 4.2.2 for additional information.

[47] Electrification refers to a combination of system level transformation and use-case level technology changes including the grid infrastructure required to support growing electric load. System level electrification includes the incremental electricity generation, storage, and supporting upstream grid infrastructure requirements to meet wide-scale end use electrification needs. Use-case level electrification refers to "*replacing technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically powered equivalents, such as electric vehicles or heat pumps*." (IEA).
[48] The Alternatives Study evaluated the electrification alternative on a systemwide basis at a high level, and on an end use-case basis for more in-depth comparison of the alternatives.

Table 4: Portfolio of Potential Alternatives Identified for Evaluation

Category	Selected for Consideration in Step 2	Not Selected for Consideration in Step 2[49]
Potential Hydrogen Delivery Alternatives	• Localized hub • Power transmission & distribution (T&D) with in-basin hydrogen production • Liquid hydrogen trucking • Gaseous hydrogen trucking • Liquid hydrogen shipping • Methanol shipping • Ammonia shipping[50] • Intermodal transport (liquid hydrogen trucking and liquid hydrogen rail)[51]	• No alternative was excluded
Potential Non-Hydrogen Alternatives	• Electrification • Carbon Capture & Storage (CCS)	• Renewable Natural Gas (RNG) • Energy efficiency • Nuclear power generation • Hydro power generation • Geothermal power generation • Plug-in hybrid vehicles • Biofuel vehicles • Ethanol vehicles

Steps 2-4: Evaluate alternatives, dismiss those that fail to satisfy Step 2 criteria, and select alternatives to carry forward for further analysis.

The Alternatives Study conducted an initial assessment of each group of pre-screened alternatives. The purpose of the initial assessment was to determine which alternatives met the criteria before carrying forward the selected alternatives for further analysis in the Cost Effectiveness Study and the Environmental Analysis.

Once alternatives were established, a set of key assessment criteria were identified and tailored to each category of alternatives. These criteria included state policy, technological maturity, range of

[49] These other clean fuels and technologies were considered in Step 1 but screened out for further evaluation. See Section 4.2 for details on the rationale.
[50] Ammonia shipping and Intermodal transport (liquid hydrogen trucking and liquid hydrogen rail) were evaluated in Step 3 (of the six-step process as discussed above) but not selected for further analysis in the Cost Effectiveness Study or Environmental Analysis. See Appendix 7.4.3 for more details.
[51] Ibid.

deliverability (distance), reliability and resiliency, ease of implementation, end-user requirements, and scalability. These criteria were developed in consideration of the need for Angeles Link, among other factors, and provided a framework to select which alternatives should be carried forward for cost and environmental impact assessments in accordance with D.22-12-055's requirements to evaluate the associated costs and environmental impacts of alternatives.[52] The criteria were applied to each category of alternative based on the applicability of the criteria as shown in Table 5 below for Hydrogen Delivery Alternatives and Table 6 for Non-Hydrogen Alternatives. For example, range of deliverability can be a critical driver for Hydrogen Delivery Alternatives as some alternatives (e.g., gaseous, and liquid hydrogen trucking) may have optimal range requirements to achieve commercial viability based on the volume and distance (range) of hydrogen transported. This consideration is not applicable to the use case level assessment of Non-Hydrogen Alternatives like electrification and CCS.

Table 5: Criteria Used to Assess Hydrogen Delivery Alternatives

Hydrogen Delivery Alternatives	Assessment Criteria				
1. Localized hub 2. Power transmission & distribution (T&D) with in-basin hydrogen production 3. Liquid hydrogen trucking 4. Gaseous hydrogen trucking 5. Liquid hydrogen shipping 6. Methanol shipping 7. Ammonia shipping 8. Intermodal transport[53]	State Policy	Range	Reliability & Resiliency	Ease of Implementation	Scalability

Table 6: Criteria Used to Assess Non-Hydrogen Alternatives

Non-Hydrogen Alternatives	Assessment Criteria				
1. Electrification 2. CCS	State Policy	Tech. Maturity	Reliability & Resiliency	End User Requirements	Scalability

After the alternatives were evaluated against the criteria, any alternatives that were determined not to meet the criteria were dismissed from further analysis, while all other alternatives were carried forward to the Cost Effectiveness Study (to evaluate the cost-effectiveness of the alternatives) and the

[52] D.22-12-055.
[53] Intermodal transport includes a combination of Liquid Hydrogen Trucking and Liquid Rail transportation.

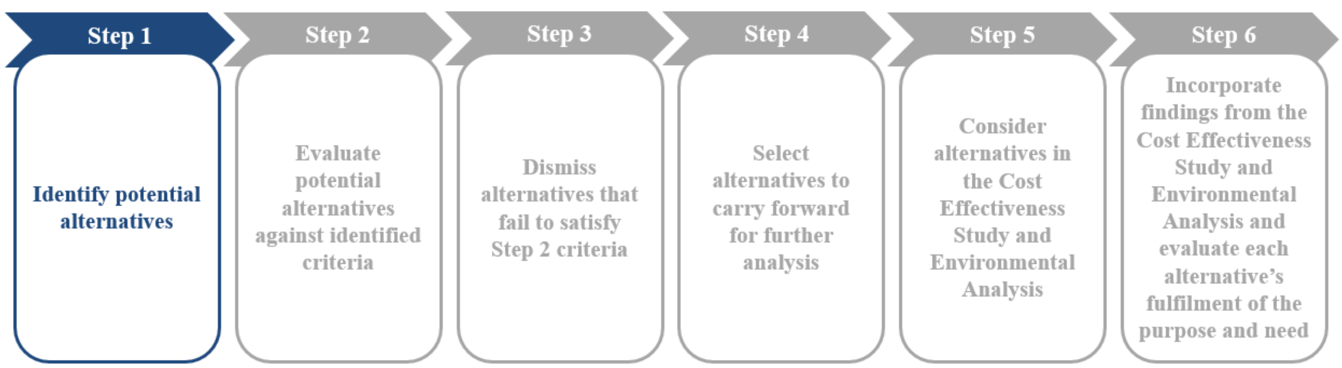
Environmental Analysis (to evaluate associated environmental impacts of the alternatives). A more detailed discussion explaining why certain alternatives were not carried forward for further analysis is provided in Section 4.3 of this report.

Steps 5-6: Consider alternatives in the Cost Effectiveness Study and Environmental Analysis, incorporate findings from the Cost Effectiveness Study and Environmental Analysis, and evaluate alternatives' fulfillment of the purpose and need.

Summary findings from the Cost Effectiveness Study and the Environmental Analysis have been incorporated into this Alternatives Study. Angeles Link and alternatives were also evaluated relative to the specific elements of the purpose and need for Angeles Link. More information on the economic and environmental results and the purpose and need evaluation is included in Section 4.4 of this report. Additionally, key findings reflecting the overall strengths and weaknesses of the alternatives relative to Angeles Link based on all criteria evaluated are included in Section 5 of this report.

4.2. Identification of Alternatives

Figure 3: Six-Step Evaluation Process: Identification of Alternatives



This section describes Step 1, the identification of potential alternatives, including descriptions of identified alternatives and reasons certain alternatives (e.g., RNG) were not carried forward for further consideration. As the identification and pre-screening process incorporated different considerations for each category of alternatives, the findings for Step 1 are discussed in two sections—Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives.

4.2.1. Hydrogen Delivery Alternatives

The process to determine the Hydrogen Delivery Alternatives to be evaluated entailed identifying potentially feasible hydrogen delivery modes, focusing specifically on existing solutions for delivering clean renewable hydrogen. For the potential delivery alternatives, production and delivery configurations incompatible with the defined parameters of Angeles Link (as discussed in the Production, Demand, and Pipeline Sizing and Design Studies (Design Study)), such as transporting high-carbon-intensive hydrogen or hydrogen produced outside California, were not analyzed.

To align with the purpose and need for Angeles Link, and to meet end-user requirements, the definition of Angeles Link and alternatives for the purposes of this study and the Cost Effectiveness Study included hydrogen transportation as well as some baseline assumptions about third-party production, storage,[54] and specialized handling that is likely to be incorporated at full system build out. In addition, the alternatives were defined to make them comparable on a like for like basis, meaning they must all achieve the same scale; transport hydrogen produced in similar locations and via similar technology where possible; be limited to California; and have access to storage that could help support energy system reliability and resiliency in the longer term. As an exception to the requirement for all alternatives to achieve a similar production and delivery capacity, a localized hydrogen hub was considered as a Hydrogen Delivery Alternative pursuant to the CPUC's direction in D.22-12-055 to consider a localized hydrogen hub among Angeles Link alternatives.

The Design Study evaluated the conceptual development of clean renewable hydrogen pipeline routes based on the potential third-party production and storage that could be developed for the larger hydrogen economy in California as illustrated in Figure 4 below.

For purposes of this study, assumptions include the following:

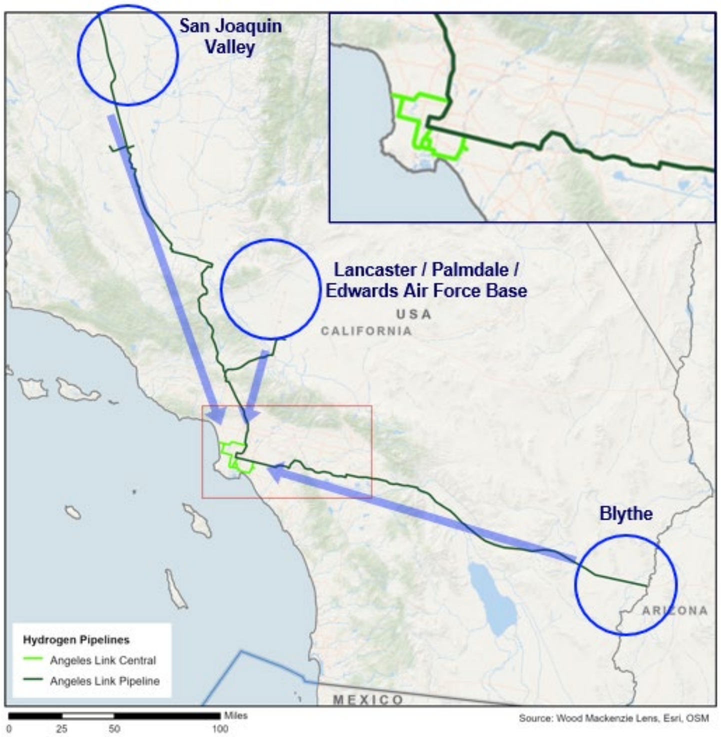
- Third-party production resources located broadly in SJV, Lancaster, and Blythe areas.[55]

[54] Clean hydrogen production and above-ground and underground storage is not currently part of the design of Angeles Link. As the design for Angeles Link is further developed, and system requirements are more clearly defined, the role of storage to support regional hydrogen producers and end users should be considered. Distributed storage equipment located at third-party production and end user sites, along with line packing, which refers to storing and then withdrawing gas supplies from the pipeline, can provide storage capacity as larger scale storage technologies mature and are deployed over time to support regional hydrogen hub requirements. For additional storage considerations see the Cost Effectiveness Study Appendix 7.5.1.

[55] The Design Study and Preliminary Routing/Configuration Analysis prepared as separate Angeles Link Phase 1 analyses concluded Angeles Link could be designed to deliver the total 1.5 Mtpa of clean renewable hydrogen to end users from production located near San Joaquin Valley and Lancaster, excluding Blythe.

- Delivery in Southern California, including to the Port of Los Angeles and Port of Long Beach with the ability to support demand in Central California.
- Development of third-party storage resources, such as above/below ground storage facilities.

Figure 4: Illustrative Map of Angeles Link and Delivery Alternatives Key Locations[56]



4.2.1.1. Hydrogen Delivery Alternatives Selected for Further Evaluation

The Alternatives Study identified six delivery methods and nine Hydrogen Delivery Alternatives as descried in Table 7 below. This included hydrogen transport using a pipeline system, hydrogen transport using trucks (as compressed gas and as liquid), rail, ship (liquid hydrogen, and derivatives such as methanol, and ammonia), power T&D with in-basin hydrogen production, and a localized clean renewable hydrogen hub.

As mentioned previously, scope configurations for each delivery alternative were customized based on their inherent technical and operational requirements and constraints. Specifically for several alternatives, solar generation, hydrogen production, and storage sites were adjusted to reduce logistical complexity, while still achieving scale, supporting system reliability and resiliency to the extent

[56] The systems would be designed to serve demand along their routes.

possible. For example, liquid hydrogen above ground storage was assumed for delivery alternatives where it was not possible for hydrogen production to access geological storage sites considered in the Production Study.

Table 7: Hydrogen Delivery Alternatives Descriptions[57]

Delivery Method	Delivery Alternative	Description
Pipeline	Angeles Link	A dedicated pipeline system designed to transport clean renewable hydrogen gas from third-party production sites to end-users in Central and Southern California, including the L.A. Basin. Full Project Description in Section 3.1.
Truck	Liquid Hydrogen Trucking	Hydrogen produced at the defined production locations is liquefied and loaded at each production site to liquid hydrogen trucks and then transported to end users. Each truck can transport up to 4 tonnes (metric tons) of hydrogen per load, while loading bays can dispatch 4 trucks per day. Assumes vehicle stock turnover from diesel trucks to fuel cell electric drive trains in the 2030s to meet California's decarbonization goals. Trucks would use existing highways, following corridors similar to conceptual pipeline routes. This alternative assumes the use of underground storage (such as depleted oil fields), which would be connected via liquid trucks. Assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports of Los Angeles and Long Beach (Ports).
	Gaseous Hydrogen Trucking	Hydrogen produced at the identified production locations is compressed and loaded at production facilities, then transported to end users via compressed hydrogen trucks. Each truck can transport up to 1 tonne of hydrogen per load, while loading bays can dispatch 5 trucks per day. Assumes vehicle stock turnover from diesel trucks to fuel cell electric drive trains in the 2030s to meet California's decarbonization goals. Trucks would use existing highways, following corridors similar to conceptual pipeline routes. This alternative assumes the use of underground storage (such as depleted oil fields), which would be connected via gaseous trucks. Assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.
Ship	Liquid Hydrogen Shipping	Production of hydrogen in Central and Northern California is transported via a pipeline to a liquefaction terminal in the nearby port. Liquid hydrogen is loaded into 10,000 cubic meter vessels (~700 tonnes). These vessels transport the hydrogen to L.A. Ports, which are transferred into liquid storage vessels and then regasified at the terminal to be directly serviced at the interconnection point at the Ports. Assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.
	Methanol Shipping	Production of hydrogen in Central and Northern California is transported via a pipeline to a methanol conversion plant in nearby ports. The methanol is transferred onto a methanol vessel intended to transport hydrogen as methanol to L.A. Ports. Methanol is then transferred into a methanol-to-hydrogen reconversion facility. After reconversion, the hydrogen is stored as liquid hydrogen before being regasified to be directly serviced at the interconnection point at the Ports. Assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.
	Ammonia Shipping	Production of hydrogen in Central and Northern California is transported via a pipeline to an ammonia conversion plant in nearby ports. The ammonia is transferred into an ammonia vessel intended to transport hydrogen as ammonia to L.A. Ports. Ammonia is then transferred into an

[57] Refer to Cost Effectiveness Study for additional information, including maps.

Delivery Method	Delivery Alternative	Description
		ammonia-to-hydrogen reconversion facility. After reconversion, the hydrogen is stored as liquid hydrogen before being regasified to be directly serviced at the interconnection point at the Ports. Assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.
Power T&D with In-Basin Production	Power T&D with In-Basin Production	Involves transmitting renewable energy as electrons through multiple 500 kV AC electric power lines, connecting solar production to the L.A. Basin from the same production sites and generally via the same potential conceptual Angeles Link pipeline corridors. Hydrogen production would occur in-basin, with a distribution pipeline interconnection to end users, including the Ports. This assumes all new transmission lines with no interconnection to the existing grid. To meet reliability requirements, this option assumes liquid storage in-basin.
Localized Hub	Localized Hub	Production is located in the L.A. Basin, within a 40-mile radius centered at the Port of Los Angeles and Port of Long Beach and expanding inland, in close proximity to end users. Hydrogen production assumes small-scale solar and production in-basin. The alternative also includes pipelines for distribution in the L.A. Basin, as well as in-basin above-ground liquid storage.[58]
Intermodal Transport	Liquid Truck / Liquid Rail	Hydrogen produced is liquefied at production facilities, then transferred to rail cars via trucks to loading terminals. A liquid hydrogen truck fleet would transport the hydrogen to the nearest railroad loading terminal, where it would be transferred into rail cars. Once in the terminal, each rail car can transport up to 4.5 tonnes of hydrogen.[59] Hydrogen is transported in liquid form along rail routes to ports, then stored in liquid state, before being regasified to be directly serviced at the interconnection points at the ports. Assumes a distribution pipeline with interconnection to the ports.

4.2.1.2. Hydrogen Delivery Alternatives Not Advanced for Further Evaluation

All the potential Hydrogen Delivery Alternatives, including the localized hub, were advanced for further evaluation.

4.2.2. Non-Hydrogen Alternatives

The process for selecting Non-Hydrogen Alternatives for evaluation was informed by the Demand Study, which provided end-use cases across the mobility, power, and industrial sectors. The Demand Study found that projected hydrogen demand in these sectors ranged from ~0.02 Mtpa in the cement sector to 1.7 Mtpa in the power generation sector by 2045.[60] The selection process prioritized non-hydrogen decarbonization alternatives that could support the purpose and need for Angeles Link. Electrification was considered as a Non-Hydrogen Alternative pursuant to the CPUC's direction in

[58] Detailed definition for Localized Hub is described in Appendix 7.1.1.
[59] 4.5 tonnes of hydrogen were estimated assuming the same energy density of a liquid truck and adjusting to the volume of a rail car. More detail on the capacity and sources of a liquid truck is available in the Cost Effectiveness Study Appendix 7.3.1.2.2.
[60] Based on "Moderate Case". See Demand Study for additional information.

D.22-12-055 to consider electrification among Angeles Link alternatives.[61] Other potential Non-Hydrogen Alternatives identified for screening align with the CARB 2022 Scoping Plan objectives to meet California's decarbonization goals. The identified Non-Hydrogen Alternatives include electrification, CCS, and other clean fuel sources and technologies. These other fuels and technologies included: (i) RNG, (ii) energy efficiency (EE), (iii) ethanol and plug-in hybrids and biofuels specifically in the mobility sector, and (iv) nuclear power generation, hydro power generation, and geothermal power generation specifically in the power sector as identified in Table 8.

[61] This study is being prepared pursuant to the CPUC Decision (D.22-12-055, Ordering Paragraph [OP] 6 (d)), which states SoCalGas shall share findings from the Phase 1 feasibility studies that consider and evaluate project alternatives, including a localized hydrogen hub or electrification.

Table 8: Mapping of Non-Hydrogen Alternatives to Use Cases[62]

Sector[63]		Electrification	CCS	Other Technologies and Fuels
Mobility (long-haul, heavy-duty) *1.0 Mtpa*		Battery electric vehicles	Not applicable to use case	RNG, EE, ethanol, and biofuel vehicles
Power (clean reliable) *1.7 Mtpa*		Battery energy storage	Gas + CCS power plant[64]	RNG, EE, nuclear, hydro, geothermal
Industrial *1.2 Mtpa*	Cogeneration *0.4 Mtpa*	Not applicable to use case	Gas + CCS cogeneration facility	RNG, EE
	Refineries (process H_2) *0.7 Mtpa*	Not applicable to use case	Unabated hydrogen from SMR + CCS	EE
	Cement (fuel switching) *0.02 Mtpa*	Electric kiln	Gas + CCS kiln	RNG, EE
	Food & Beverage (fuel switching) *0.03 Mtpa*	Electric oven/fryer	Not applicable to use case	RNG, EE

4.2.2.1. Non-Hydrogen Alternatives Selected for Further Evaluation

Based on an initial screening of the potential Non-Hydrogen Alternatives to determine their ability to meet the purpose and need for Angeles Link as a standalone alternative, the following were selected for further assessment in this study:

[62] The use case categories considered for the evaluation of Non-Hydrogen Alternatives were informed by the Demand Study.
[63] Circles reflect 2045 projected hydrogen demand (in Mtpa) in the Demand Study "Moderate Case", with the exception of refineries, for which demand was only projected in the "Ambitious Case". See Demand Study for additional information.
[64] Gas + CCS refers to a CO_2 capture technology that captures emissions from an existing natural gas facility.

Electrification refers to a combination of system level[65] transformation and use case level[66] technology changes including the grid infrastructure required to support growing electric load. The assessment of electrification was primarily conducted on a use case level for the purposes of this study (e.g., fuel cell electric vehicle (FCEV) vs. BEV for heavy-duty vehicles for the mobility sector). A broader evaluation of system-level electrification considerations was also conducted based on a high-level review of existing research, third-party studies, and California's decarbonization goals. These considerations are summarized in Section 4.3.2.1.1, with additional details in Appendix 7.3.3.

CCS refers to carbon capture and sequestration technology, which is the process of storing carbon dioxide in underground geologic formations. The assessment of CCS was conducted on a use case level for the purposes of this study (e.g., hydrogen vs. CCS for power generation), and certain system-level considerations and assumptions were incorporated into the use case level assessments, including the implications of the CO_2 storage and transportation infrastructure needed to support CCS applications.

4.2.2.2. Non-Hydrogen Alternatives Not Advanced for Further Evaluation

The following alternatives were considered in the Step 1 pre-screening process but not advanced for further assessment. While these solutions may play important roles in support of California's decarbonization targets, they were found to be unlikely to fully address the energy equivalent of Angeles Link's hydrogen demand requirements as standalone alternatives.

RNG derived from organic waste has been identified as an important clean fuel alternative in supporting California's ambitious decarbonization and methane emission reduction goals, aligning with the State's legislative policies and mandates, such as Senate Bill (SB) 1440[67] and SB 1383.[68] As discussed in the 2022 CARB Scoping Plan, RNG (biomethane) can help offset usage of traditional fuels to meet California's decarbonization objectives.[69] SB 1440 specifically requires RNG procurement of 17.6 billion cubic feet (BCF) annually by 2025, and 72.8 BCF by 2030, which represents 12% of the current

[65] System level electrification includes the incremental electricity generation, storage, and supporting upstream grid infrastructure requirements to meet wide-scale end use electrification needs.
[66] Use-case level electrification refers to replacing technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically powered equivalents, such as electric vehicles or heat pumps. More detail at [IEA Electrification Overview.]
[67] SB 1440 (Hueso, Chapter 739, Statutes of 2018) sets Biomethane (RNG) procurement targets for gas utilities to reduce GHG emissions in remaining pipeline gas and reduce methane emissions from organic waste.
[68] [Senate Bill No. 1383.]
[69] [2022 Scoping Plan Update (ca.gov).]

residential and small business gas usage in 2020.[70] Organic waste feedstock-derived RNG provides a lower-carbon alternative (or a negative carbon alternative for some feedstocks) to conventional natural gas, creating an opportunity to utilize existing gas infrastructure for cleaner energy applications. Its role is crucial in the initial phases of California's low-carbon transition, particularly in sectors where direct electrification is challenging. RNG plays a key role in meeting the SB 1440 procurement targets, SB 1383 procurement requirements, and the voluntary market (e.g., customers seeking to procure RNG to help meet their sustainability goals). However, RNG's potential to fully address the energy equivalent of Angeles Link's hydrogen demand requirements as a standalone alternative is tempered by statewide supply availability.

Energy efficiency is a key decarbonization tool in nearly every sector, as it allows for the overall reduction in energy inputs required to serve growing future energy demand. As defined by the Department of Energy (DOE), energy efficiency is the use of less energy to perform the same task or produce the same result.[71] Energy efficiency is a partial decarbonization solution on its own and cannot be evaluated on a standalone basis relative to Angeles Link and other alternatives from an energy equivalency perspective.

In the **mobility** sector, the following fuels were considered but not advanced for further analysis as they each produce tailpipe emissions and are therefore not compliant with California's Advanced Clean Trucks and Advanced Clean Fleets regulations:[72]

- **Ethanol,** also known as flex fuel, is a gasoline-ethanol blend containing 51%-83% ethanol and capable of serving flexible fuel vehicles in the mobility sector.[73] Ethanol is a sustainable fuel produced from various plant components known as biomass. Ethanol is an alcohol that is blended with gasoline to boost octane while reducing carbon monoxide and other smog-causing pollutants.[74]
- **Plug-in hybrids** use batteries to power an electric motor, as well as another fuel, such as gasoline or diesel, to power an internal combustion engine or other propulsion source.[75] Several

[70] CPUC Sets Biomethane Targets for Utilities (ca.gov).
[71] Energy Efficiency: Buildings and Industry.
[72] Advanced Clean Fleets, California Air Resources Board.
[73] Alternative Fuels Data Center.
[74] Biofuel Basics | Department of Energy.
[75] Alternative Fuels Data Center: Plug-In Hybrid Electric Vehicles (energy.gov).

light-duty plug-in hybrids are commercially available, and medium-duty vehicles are beginning to enter the market. Medium- and heavy-duty vehicles can also be modified into plug-in hybrid vehicles.[76]

- **Biofuels**, such as biodiesel, are renewable, biodegradable fuels produced from vegetable oils, animal fats, or recycled restaurant grease.[77]

In the **power** sector, the following technologies were considered but not advanced for further analysis for the following reasons:

- **Nuclear power generation** is the energy harnessed to produce electricity through nuclear fission inside a reactor. Due to the absence of state plans for new-build units and the planned retirement of Diablo Canyon Power Plant in 2030,[78] nuclear power was not considered for further evaluation.
- **Hydro power generation** is a clean and renewable source of energy allowing for power generation from the natural flow of water by using the elevation difference created by a dam or a water diversion system.[79] Due to limited new capacity additions forecasted in the CARB Scoping Plan,[80] hydro units (including pumped hydro storage) were screened out from further consideration in this study.
- **Geothermal power generation** uses the heat energy extracted from the geothermal resources from underground geologic reservoirs of hot water to produce electricity.[81] Even though geothermal energy has the potential to play a role in supporting decarbonization goals in California, new geothermal capacity is expected to be minimal, as CARB's Scoping Plan forecasts only up to 1 GW of geothermal capacity additions by 2045.[82]

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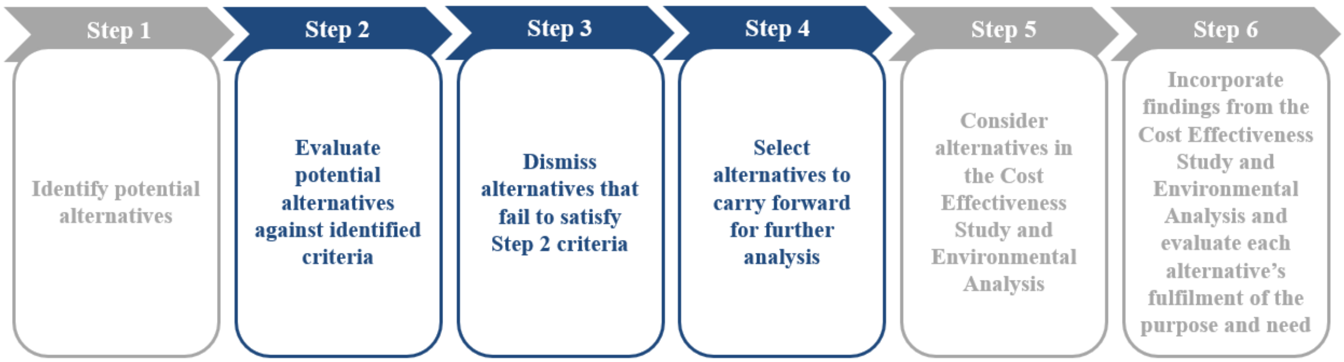
[76] Ibid.
[77] Alternative Fuels Data Center: Biodiesel Fuel Basics (energy.gov).
[78] California Energy Commission - CEC Determines Diablo Canyon Power Plant Needed to Support Grid Reliability.
[79] DOE EERE – Hydropower Basics.
[80] CARB Scoping Plan.
[81] Geothermal Energy Production Basics - NREL.
[82] CARB Scoping Plan.

4.3. Evaluation of Alternatives

Figure 5: Six-Step Evaluation Process: Evaluation of Alternatives



This section describes the evaluation criteria, methodology, and key findings from the evaluation alternatives in Steps 2-4 of the six-step evaluation framework (as illustrated in Figure 5 above). Considering the criteria are distinctive to each category of alternatives, the findings for Steps 2-4 are categorized into two sections—Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives.

4.3.1. Evaluation of Hydrogen Delivery Alternatives

Five assessment criteria were applied to evaluate Hydrogen Delivery Alternatives for advancement to the next steps in the analysis: (i) state policy; (ii) range; (iii) reliability and resiliency; (iv) ease of implementation; and (v) scalability, summarized in Table 9 below. A 4-point assessment rubric (high, good, moderate, low) was used to evaluate the extent to which each Delivery Alternative may achieve or be consistent with each criterion.

Table 9: Criteria Definitions and Assessment Rubric for Step 2 Evaluation

Criteria Selected for Screening	Definition	High	Good	Moderate	Low
State Policy	Level of alignment with California's clean energy and environmental policies	Alignment with state policy, including specific incentives or initiatives	Alignment with state policy but potential conflicts with decarbonization goals	No alignment with state policy and potential conflicts with decarbonization goals	Explicit misalignment with state policy and conflicts with decarbonization goals
Range	The distance or range of deliverability the transportation method can effectively cover for delivering hydrogen	Capable of efficiently transporting hydrogen at least the length of California	Capable of covering at least 450[83] miles or is optimal given its location - but might face inefficiencies (losses)	Moderate range with the ability to efficiently cover fewer than 450 miles in a day	Limited range due to technical or other type of constraints
Reliability and Resiliency	The capability to provide uninterrupted and/or consistent hydrogen supply and adapt to reduce the duration/magnitude of disruptive events[84]	Guarantees hydrogen supply and unparalleled adaptability to reduce duration/ magnitude of disruptive events	Infrequent hydrogen supply disruptions due to adaptability to mitigate the duration/ magnitude of disruptive events	Expected and unavoidable hydrogen supply disruptions and limited adaptability to manage disruptive events	Constant hydrogen supply disruptions and limited adaptability to manage disruptive events
Ease of Implementation	The ease with which a delivery solution can be implemented, considering technology readiness,[85] existing and complementary infrastructure, entry barriers, and construction time	Mature technology readiness, existing complementary infrastructure, and limited entry barrier and lowest construction time	Mature technology readiness, existing complementary infrastructure, and limited entry barrier but requires more complex infrastructure	Feasible technology readiness, with some complementary infra., possible entry barriers and longer time for construction	Challenged by technology readiness, technical challenges, or entry barriers
Scalability	The potential for an alternative to support California's need for 1.5 Mtpa and its ability to expand volume or extend footprint	Supports at least 1.5 Mtpa, adaptable to expand volume or extend footprint	Feasible at 1.5 Mtpa, with limited potential to expand volume or extend footprint	Feasible at 1.5 Mtpa but severely challenged by land or other constraints	Challenging or impractical to scale to 1.5 Mtpa due to infrastructure requirements

The Hydrogen Delivery Alternatives were evaluated based on the selected criteria summarized above. State Policy and Range were analyzed for each delivery method; Reliability and Resiliency and Ease of Implementation were analyzed at the alternative level (specific options within each transportation method); and Scalability was evaluated for a specific scale and scope configuration.

4.3.1.1. Evaluated Delivery Alternatives

4.3.1.1.1. State Policy

The criterion to evaluate alignment with state policy considers the degree to which Angeles Link and each Delivery Alternative supports California's decarbonization and clean energy objectives, is in line with ongoing legislative and regulatory actions, and can be developed within the parameters of existing regulatory frameworks. This criterion is evaluated for each delivery method. Figure 6 below summarizes the degree to which each potential Hydrogen Delivery Alternative aligns with state policy.

Figure 6: Level of Alignment with State Policy Across Hydrogen Delivery Alternatives

Angeles Link Pipeline System	Truck (Gas and Liquid H_2)	Ship (Liquid H_2, Methanol and Ammonia)	Power T&D With In-Basin Production	Localized Hub	Intermodal Transport (Liquid Trucking and Rail)
High	Good	Moderate	High	High	Low

High Good Moderate Low

Pipeline

Assessment: Alignment with state policy, including specific incentives or initiatives.

- ✓ Due to their ability to efficiently transport large volumes of hydrogen over long distances, pipelines have relatively low GHG emissions when compared to other alternatives, and thus align well with California's clean energy and environmental policies.
- ✓ Pipeline transport of clean renewable hydrogen can enable the scale of deployment required to support the adoption of clean renewable hydrogen on an economy-wide basis, which supports job creation and other economic benefits, as well as the integration and growth of the ARCHES

[83] Length of Angeles Link Project description.
[84] CPUC Resiliency Standards: Definitions and Metrics.
[85] See Appendix 7.4.1 for Technology Readiness Level definition.

hydrogen hub (which has been selected for federal funding by the DOE pursuant to the Infrastructure Investment and Jobs Act (IIJA) funding program).[86]

× As a linear project, pipelines can face extensive permitting processes, requiring a longer development timeline which would potentially delay the realization of decarbonization objectives.

Truck (Gas and Liquid Hydrogen)

Assessment: Alignment with state policy but potential conflicts with decarbonization goals.

✓ The emissions intensity of hydrogen trucking is expected to decline as technologies advance; for example, as vehicle emissions standards become more stringent, vehicle stocks turn over and trucks transition from diesel internal combustion engines to fuel cell drive trains, and as efficiency improvements are achieved in fuel cell drive trains.

✓ Regulatory processes for truck deployment and liquefaction/compression terminal development may have a more favorable timeline than other larger-scale alternatives.

✓ A trucking alternative is in line with state policy until a pipeline system is developed.

× Liquefaction and compression terminals for trucks are highly energy intensive and may face challenges related to emissions intensity based on their source of power.[87]

× Diesel trucks, which currently dominate the truck fleet for hydrogen transport, may face challenges in earlier years related to emissions before fleets are converted to zero emission vehicles, based on the distance travelled, quantity of diesel trucks, and number of trips.[88]

× Trucking at the scale required to meet projected demand would result in a very large number of trucks on the road, leading to an increase in road congestion.

Ship (Liquid Hydrogen, Methanol and Ammonia)

Assessment: No alignment with state policy and potential conflicts with decarbonization goals.

[86] ARCHES hydrogen hub was awarded up to $1.2 billion from the U.S. DOE to accelerate the development and deployment of clean renewable hydrogen in California, see California Selected as National Hydrogen Hub.
[87] CA-GREET3.0 Lookup Table Pathways Technical Support Documentation, pg. 37.
[88] Ibid.

- × No existing policy nor economic incentives exist to support the development of transporting clean renewable hydrogen (using ships) as derivative carriers (such as ammonia or methanol) within California.
- × Large scale facilities for hydrogen conversion/reconversion at the port of departure and receipt are highly energy intensive and may face challenges related to emissions intensity based on their source of power.

Power T&D with In-Basin Production

Assessment: ■ Alignment with state policy, including specific incentives or initiatives.

- ✓ The addition of renewable power transmission and distribution to support load in the L.A. Basin supports California's commitment to decarbonize power generation.[89]
- ✓ California's Independent System Operator (CAISO) has put into place plans and a more proactive approach to support investments in power transmission.[90]
- × Power transmission and distribution infrastructure faces extensive permitting processes, requiring a longer development timeline. [91]

Localized Hub

Assessment: ■ Alignment with state policy, including specific incentives or initiatives.

- ✓ Pipelines can transport hydrogen with low GHG emissions when compared to other alternatives.
- ✓ A localized hub with production near end users aligns with the State's decarbonization goals for end users to use more hydrogen.
- ✓ The development of additional in-basin distributed solar capacity aligns with California's clean energy goals.[92]
- × Permitting and regulatory processes for power generation, hydrogen production, and delivery infrastructure may be more challenging in a population dense area.

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[89] California Air Resources Board's (CARB) 2022 Scoping Plan for Achieving Carbon Neutrality.
[90] California ISO Approves $7.3 Billion Investment in Transmission.
[91] Transmission Project Development Timelines in California.
[92] D.22-12-055.

Intermodal Transport (Liquid Trucking and Liquid Rail)

Assessment: Low alignment with state policy and conflicts with decarbonization goals.

- × Diesel engines and locomotives transporting hydrogen may encounter challenges related to emissions and transportation and safety regulations (e.g., hydrogen transportation safety regulations for rail movement across bridges, tunnels, etc.).
- × Intermodal transfer of liquid hydrogen between different modes at transfer stations can pose safety challenges and boil-off losses.

4.3.1.1.2. Range

The distance traveled, associated volumes of transport, and end-use requirements all influence the selection of a certain transportation option/pathway. Transportation options that can cover longer distances provide options for sourcing the highest quality renewable resources for hydrogen production. Infrastructure requirements, general range capabilities, and suitability for specific transport distances (based on the volume of hydrogen transported and distances traveled) were considered when evaluating the range for each transportation mode. Range is defined as the capability to efficiently cover delivery distances and follows the 4-point scale ranking defined in Table 9. This criterion is evaluated for each delivery method.

Figure 7 below summarizes the extent to which each delivery alternative can serve hydrogen for the range envisioned between major production and demand hubs, followed by a summary of the advantages and challenges for each delivery alternative associated with range.

Figure 7: Level of Alignment with Range Across Hydrogen Delivery Alternatives

Angeles Link Pipeline System	Truck (Gas and Liquid H_2)	Ship (Liquid H_2, Methanol and Ammonia)	Power T&D With In-Basin Production	Localized Hub	Intermodal Transport (Liquid Trucking and Rail)

High **Good** **Moderate** **Low**

Pipeline

Assessment: Capable of efficiently transporting hydrogen at least the length of California.

- ✓ Pipelines have high range capabilities, making them efficient for transporting hydrogen over long distances, as demonstrated by the extensive network established in the U.S. Gulf Coast.[93]

Truck (Gas and Liquid Hydrogen)

Assessment: Moderate range with the ability to efficiently cover fewer than 450 miles in a day.

- ✓ Compressed gaseous hydrogen (GH_2) and liquefied hydrogen (LH_2) trucking are an effective solution for supplying hydrogen to dispersed consumers at shorter distances in local and urban areas.[94]
- × Trucking larger volumes of hydrogen over longer distances can be economically challenging due to boil-off losses, labor, and fuel costs.
- × Liquid or gaseous hydrogen trucks may need more frequent refueling or replenishment relative to other transportation modes.

Ship (Liquid Hydrogen, Methanol and Ammonia)

Assessment: Capable of efficiently transporting hydrogen at least the length of California.

- ✓ Ships can cover long distances.
- × Ships require complex multi-modal and large-scale conversion/liquefaction infrastructure for conversion before shipping and for large scale reconversion/regasification at the point of delivery. The complex infrastructure value chain has the potential for conversion/boil-off losses.

Power T&D with In-Basin Production

Assessment: Capable of covering at least 450 miles, or is optimal given supply and demand locations, but might face inefficiencies (losses).

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[93] The U.S. has ~1,600 miles of dedicated hydrogen pipelines network (with varying pipeline mileage), connecting multiple production and demand centers. See National Petroleum Councill, Harnessing Hydrogen – A Key Element of the US Energy Future, Appendix J, Table 3-6.

[94] In the U.S., GH_2 and LH_2 are the most common forms of hydrogen transported by truck. See National Petroleum Councill, Harnessing Hydrogen – A Key Element of the US Energy Future, Chapter 3: LCI Hydrogen—Connecting Infrastructure, pg. 24.

- ✓ Bulk power transmission systems enable the transmission of electrons from high quality renewable resources over longer distances to hydrogen production near demand locations.
- × Significant transmission losses coupled with potential grid congestion impacts, or operational challenges from utilization and solar variability, could lead to lower transmission throughput.[95]

Localized Hub

Assessment: Capable of supporting the development of a dedicated clean renewable hydrogen pipeline system located within the L.A. Basin with production and end use in proximity (range).

- ✓ Localized hub could connect local (distributed) clean renewable hydrogen producers to multiple end users in the hard-to-electrify sectors via open access, common carrier pipeline infrastructure.
- × The ability to extend service to demand outside of the localized hub would be limited due to limited renewable and hydrogen production capacity in-basin.

Intermodal Transport (Liquid Trucking and Liquid Rail)

Assessment: Capable of covering the transport distances as envisioned for the Angeles Link - but might face inefficiencies (losses).

- ✓ Transportation by truck is suitable for short- or mid-distance transport. Rail systems can support longer distances.
- × There are challenges associated with rail transport safety regulations over longer distances (e.g., hydrogen transportation safety regulations for rail movement across bridges, tunnels, etc.).

4.3.1.1.3. Reliability and Resiliency

Reliability and Resiliency evaluates an alternative's ability to provide uninterrupted and/or consistent hydrogen supply and to reduce the duration/magnitude of disruptive events. The assessment follows the 4-point scale ranking as defined in Table 9. This criterion is evaluated for each delivery alternative (e.g., shipping as liquid hydrogen vs. ammonia) whereas the previous criteria have been evaluated for each delivery method (e.g., shipping). Figure 8 below summarizes the degree to which each potential

[95] U.S. Energy Information Administration, HARNESSING HYDROGEN - A Key Element of the U.S. Energy Future (npc.org), see: Frequently Asked Questions (FAQs) - U.S. Energy Information Administration (EIA).

alternative achieves reliability and resiliency, followed by a summary of the advantages and challenges for each alternative associated with reliability and resiliency.

Figure 8: Level of Alignment with Reliability and Resiliency Across Hydrogen Delivery Alternatives

Angeles Link Pipeline System	Gaseous Hydrogen Trucking	Liquid Hydrogen Trucking	Liquid Hydrogen Shipping	Methanol Shipping	Ammonia Shipping	Power T&D With In-Basin Production	Localized Hub	Intermodal Transport (Liquid Trucking and Rail)

High **Good** **Moderate** **Low**

Angeles Link

Assessment: Infrequent hydrogen supply disruptions due to the adaptability to mitigate the duration/ magnitude of disruptive events.

- ✓ Hydrogen pipelines are well suited to integrate supply and demand, with the ability to connect production and storage (e.g., third-party storage resources) across strategic locations along their routes and the ability to provide storage in the pipeline system (for example, by linepacking). This integration provides operational flexibility, system scalability, and robust reliability and resiliency as the demand for hydrogen scales over time.
- ✓ Pipelines can be built underground and are therefore typically more resilient to extreme weather and other external factors.
- ✓ Pipeline systems at scale have the potential to provide energy system reliability and resiliency and help advance California's emissions reduction goals in tandem, by providing an alternative pathway for the delivery of renewable energy as clean renewable hydrogen.
- × Pipelines require significant lead time to provide access to new/distant service areas and storage locations beyond those accounted for in the pipeline system's initial design.

Trucking (General)

- ✓ Hydrogen trucking offers flexibility to adapt to potential disruptions, as the fleet can be rerouted or rescheduled as needed.

- × Truck load cycles are slower than pipelines accessing hydrogen storage locations, which results in slower dispatchability.
- × Trucks are more likely to face supply disruptions due to traffic, road closures, or accidents, especially when transporting over long distances, which could affect system reliability.

Gaseous Hydrogen Trucking

Assessment: Unforeseen hydrogen supply disruptions and limited adaptability to manage disruptive events.

- × Gaseous hydrogen trucking serving long distance hydrogen transport necessitates a large compression terminal and gaseous hydrogen trucking fleet covering long distances to transport hydrogen, which can potentially lead to supply disruptions impacting reliability. In the mobility sector, California has previously experienced hydrogen supply disruptions (e.g., lack of availability of gaseous hydrogen) to serve the existing hydrogen refueling stations for the light duty FCEV sector.[96]

Liquid Hydrogen Trucking

Assessment: Hydrogen supply disruptions can be lessened (albeit not eliminated) due to adaptability to mitigate the duration/magnitude of disruptive events.

- ✓ Hydrogen in its liquid form has a much higher energy density compared to its gaseous form, meaning fewer LH_2 trucks and deliveries are needed for the same energy content, which reduces exposure to potential disruptions.
- × Even with the benefit of a smaller fleet and fewer deliveries, LH_2 trucks still face higher potential for supply disruptions when transporting over long distances than pipelines.

Shipping (General)

- ✓ Hydrogen demand located near delivery hubs and ports would benefit from close proximity to supply produced at the port or delivered via ships.
- × Shipped hydrogen may offer limited access to certain demand centers and/or may require additional infrastructure to reach demand centers not located near ports.

[96] Retail Hydrogen Station Network Status in California.

- × Delivery via ship exposes hydrogen supply to port congestion, weather disruptions, and supply chain constraints as seen during events like the COVID-19 pandemic, Russia's war in Ukraine,[97] and the Suez Canal blockage,[98] potentially diminishing reliability.

Liquid Hydrogen Shipping

Assessment: Expected and unavoidable hydrogen supply disruptions and limited adaptability to manage disruptive events.

- ✓ Liquid hydrogen can be re-gasified and consumed as a gaseous fuel, which is a relatively less complex, costly, and energy intensive process than reconverting ammonia or methanol to hydrogen.
- × With current liquified hydrogen shipping technology, more ships and deliveries are required for the same energy content as ammonia and methanol, creating more opportunity for disruption.

Methanol Shipping

Assessment: Expected and unavoidable hydrogen supply disruptions and limited adaptability to manage disruptive events.

- ✓ Methanol can be more easily stored than hydrogen and used directly as a fuel or converted back to hydrogen if necessary, providing flexibility via multiple pathways to energy utilization.
- × The extra steps in the value chain process to transform hydrogen into methanol and reconvert methanol to hydrogen would create more opportunities for disruption.

Ammonia Shipping

Assessment: Constant hydrogen supply disruptions and limited adaptability to manage disruptive events.

- ✓ Ammonia can be easily stored and used directly as a fuel or converted back to hydrogen if necessary, providing flexibility via multiple pathways to energy utilization.

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[97] LNG Shipping as a Diversification Tool for Energy Security: The Impact of the Ukraine-Russia War on LNG Ship Orders, Journal of ETA Maritime Science 2024.
[98] Blockage of the Suez Canal, March 2021.

- × The process for ammonia production (i.e. Haber-Bosch) requires a 24/7 stream of electricity, hydrogen, and nitrogen as feedstocks.[99] Clean renewable electricity and hydrogen produced via solar generation face challenges in this process due to the intra-day production profile of solar. This incompatibility could create reliability challenges for ammonia as a hydrogen transportation pathway.

In-Basin Production with Power T&D

Assessment: Infrequent hydrogen supply disruptions due to adaptability to mitigate the duration/ magnitude of disruptive events.

- ✓ In-basin production is closer to demand, supporting market access and reducing risk of disruption to delivery infrastructure.
- ✓ Additional transmission lines contribute to the system's reliability.
- × In-basin above-ground storage capacity may not be sufficient to provide hydrogen supply reliability for the scale of hydrogen demand projected long-term.
- × Due to the significant transmission mileage required to support in-basin hydrogen production[100], this alternative is at higher risk of interruption for Power Safety Public Shut-off (PSPS)[101] events, which could result in system reliability impacts.
- × Development timelines for new transmission and distribution infrastructure may create limitations to respond to growing hydrogen demand and to deliver on production resiliency needs.[102]

[99] Refer to Appendix 7.3.1; the process of converting hydrogen to ammonia (known as Haber Bosch ammonia synthesis) requires constant input of hydrogen and power, which is not conducive with non-grid interconnected clean renewable hydrogen production from solar facilities.

[100] The scope configuration for In-Basin Hydrogen Production with T&D requires 400 miles of electricity transmission corridor to connect solar generation capacity locations in San Joaquin Valley, Lancaster, and Blythe to hydrogen production in the L.A. Basin. Refer to Table 3, Appendix 7.2.2.2, and Appendix 7.3.1.2.4 in the Cost Effectiveness Study.

[101] The In-Basin Production with Transmission and Distribution alternative requires over 400 miles of transmission line corridor, making it more likely to face Public Safety Power Shut-Offs than other alternatives. See Public Safety Power Shutoffs (ca.gov).

[102] Transmission Project Development Timelines in California.

Localized Hub

Assessment: Infrequent hydrogen supply disruptions due to the adaptability to mitigate the duration/ magnitude of disruptive events.

- ✓ Avoiding the need to transport hydrogen from external sites to demand centers minimizes the risks of transport disruptions.
- × In-basin above-ground storage capacity may not be sufficient to provide hydrogen supply reliability for the scale of hydrogen demand projected long-term.
- × The ability to flexibly serve demand outside of the localized hub would be limited due to limited renewable and hydrogen production capacity in-basin.
- × Limited in-basin electricity and hydrogen production capacity could impact reliability for power needs and, in the long-term, the mobility sector.

Intermodal Transport (Liquid Trucking and Rail)

Assessment: Constant hydrogen supply disruptions and limited adaptability to manage disruptive events.

- × Integration of truck and train transport, each with its own infrastructure needs, shipping sizes, schedules, and regulatory requirements, adds complexity that can lead to challenges and disruptions.
- × Reliability is limited by the challenges associated with all the individual delivery methods outlined previously for trucking and shipping.

4.3.1.1.4. Ease of Implementation

Ease of implementation evaluates how readily each Hydrogen Delivery Alternative can be implemented, considering technical and commercial maturity, the availability of existing and complementary infrastructure, construction time, and regulatory frameworks in place to support the implementation of each delivery alternative. The assessment follows the 4-point scale to categorize the ease of implementation for each alternative as defined in Table 9. To assess technical and commercial maturity, Technology Readiness Levels (TRL) were evaluated to further assess the ease of implementation of each Hydrogen Delivery Alternative. TRLs measure the operational readiness of a technology, providing insights into its commercial viability, and are defined in the International Energy Agency's (IEA) Clean

Tech Guide. A detailed description of each TRL score can be found in Appendix 7.4.1.[103] Technologies rated with a TRL of 9 or above are considered technically and commercially mature technologies that are operational at-scale in the U.S. or in other markets globally.

Gaseous and liquid hydrogen trucking, along with ammonia shipping, are assessed at a TRL of 11, indicating technical and commercial maturity has been demonstrated in multiple market environments. Hydrogen pipelines, such as Angeles Link, are the primary method used to transport hydrogen over short and long distance to large scale consumers.[104] Hydrogen pipelines are assessed at a TRL of 9, with demonstrated technical and commercial maturity in relevant environments. In the U.S. the largest pipeline systems are in the Gulf Coast region, where 1,500 miles of pipeline have been developed to serve large consumers such as refineries, ammonia and methanol production facilities.[105] Liquid hydrogen shipping is assessed at a TRL of 7 and is currently in the pre-commercial demonstration phase. Methanol and ammonia shipping is assessed at a TRL of 11, with traditional methanol and ammonia shipped commercially as a global commodity.[106]

Figure 9 below summarizes the degree to which each potential delivery alternative may have ease of implementation, followed by a summary of the advantages and challenges for each alternative associated with ease of implementation.

Figure 9: Ease of Implementation Across H_2 Delivery Alternatives

Angeles Link Pipeline System	Gaseous Hydrogen Trucking	Liquid Hydrogen Trucking	Liquid Hydrogen Shipping	Methanol Shipping	Ammonia Shipping	Power T&D With In-Basin Production	Localized Hub	Intermodal Transport (Liquid Trucking and Rail)

High Good Moderate Low

103 Appendix 7.4.1 Technology Readiness Levels for Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives
104 The U.S. has ~1,600 miles of dedicated hydrogen pipelines network (with varying pipeline mileage), connecting multiple production and demand centers. See National Petroleum Councill, Harnessing Hydrogen – A Key Element of the US Energy Future, Appendix J, table 3-6.
105 Department of Energy Hydrogen Fuel Cell and Technology Office, Hydrogen Pipelines
106 The TRL for cracking of methanol of Ammonia (at-scale) back to hydrogen or regasification of liquid hydrogen (at scale) may be at the pre-commercial phase.

Angeles Link

Assessment: Feasible technology readiness with some complementary infrastructure, however, implementation faces possible entry barriers and longer time for construction.

- ✓ Gaseous pipeline implementation is understood and mature at scale throughout the U.S. and globally, which can support hydrogen pipeline development.
- ✓ Angeles Link will seek to leverage existing land rights for pipeline infrastructure throughout Central and Southern California to the extent this is feasible, potentially reducing development timelines.
- × New pipeline construction requires planning and coordination with hydrogen production and demand components of the developing hydrogen value chain, which may require a longer development timeline.
- × Long-haul pipelines require an extensive development lifecycle.[107]

Trucking (General)

- ✓ California has an existing supply chain for hydrogen compression and liquefaction technology and delivery trucks which currently serve refueling stations and the growing FCEV fleet.
- ✓ Existing highway infrastructure minimizes the need for new construction.
- ✓ Truck fleet additions, and development of new liquefaction/compression and loading terminals can be phased to match demand growth.

Gaseous Hydrogen Trucking

Assessment: Mature technology readiness, existing complementary infrastructure, and limited entry barrier and lowest construction time.

- ✓ Gaseous hydrogen compression and trucks are relatively straightforward to implement in comparison to the liquid value chain.
- × There are limits to the implementation of gaseous hydrogen trucking to serve demand once it grows past consumption of approximately 500-600 kg/d due to the capacity limit of current truck and tank technology.[108]

[107] Phases of Pipeline Construction
[108] U.S. DOE, Hydrogen Delivery Technical Team Roadmap

Liquid Hydrogen Trucking

Assessment: Mature technology readiness, existing complementary infrastructure, and limited entry barrier but requires more complex infrastructure.

- × Liquid hydrogen trucking requires more specialized infrastructure compared to gaseous transportation, to handle the conversion between gaseous and liquid states.

Shipping (General)

- ✓ Hydrogen and its carriers have the potential to leverage existing port locations and infrastructure currently in use for traditional ammonia, methanol, or liquefied natural gas (LNG).
- × New facilities required to handle hydrogen or its carriers inside ports with geospatial limitations may complicate the implementation of hydrogen or carrier shipping in some locations.

Liquid Hydrogen Shipping

Assessment: Feasible technology readiness, with some complementary infrastructure, possible entry barriers, and longer time for construction.

- ✓ Liquid hydrogen transportation does not require an additional feedstock (i.e., nitrogen for ammonia or anthropogenic CO_2 for low-carbon methanol) or additional chemical processing facilities for conversion into a hydrogen carrier.
- ✓ Shipping of liquified gases has developed into a commercially viable global market for commodities such as Liquified Natural Gas (LNG).
- × Liquid hydrogen shipping is in the very early stages, with only one prototype ship that has completed a successful voyage in the market and faces technical challenges to reduce boil off and losses.[109]
- × Liquid hydrogen import and export terminals will require retrofits to existing pipeline and storage, liquefaction/regasification infrastructure or new infrastructure that can handle the unique characteristics of hydrogen.

[109] World's First Hydrogen Carrier Departs Japan on Maiden Voyage, The Maritime Executive.

Methanol Shipping

Assessment: Feasible technology readiness with some complementary infrastructure; however, implementation faces possible entry barriers and longer time for construction.

- ✓ Methanol has the potential to leverage existing port infrastructure for traditional methanol, without reconversion to hydrogen, in limited applications such as for use as a shipping fuel.
- × Implementing reconversion infrastructure required to "crack" methanol back to its chemical components as a method for hydrogen production is highly energy intensive, releases CO_2, and is not yet demonstrated at scale, limiting methanol's potential use as a hydrogen carrier for other demand applications.

Ammonia Shipping

Assessment: Challenged by technology readiness, operational challenges, or entry barriers.

- ✓ Ammonia has the potential to leverage existing port infrastructure for traditional ammonia, without reconversion to hydrogen, in limited applications such as for green fertilizer production, and blending with coal, to reduce the carbon intensity of dispatchable power generation. [110]
- × Implementing reconversion infrastructure required to crack ammonia back to its chemical components as a method for hydrogen production is highly energy intensive and is not yet demonstrated at scale, limiting ammonia's potential use as a hydrogen carrier for other demand applications.
- × The operational requirements of ammonia production through the Haber-Bosch process mean a reliable and continuous supply of hydrogen, nitrogen, and low-carbon electricity are critical for continuous operation. Continuous access to electricity and hydrogen may be challenging if solar generation is the main source of power.

[110] National Petroleum Council. Harnessing Hydrogen: A Key Element of the U.S. Energy Future, see: HARNESSING HYDROGEN - A Key Element of the U.S. Energy Future (npc.org).

In-Basin Production with Power T&D

Assessment: Feasible technology readiness with some complementary infrastructure; however, implementation faces possible entry barriers, and longer time for construction.

- ✓ Power transmission buildout is understood and mature at scale throughout the U.S.
- × Existing rights of way likely could not be fully leveraged for new power transmission lines as a reliable system would likely require the development of multiple parallel lines.
- × Power transmission development has an extensive development lifecycle.[111]
- × Construction involves building new transmission lines with multiple substations.[112]

Localized Hub

Assessment: Feasible technology readiness for a limited scale of supply, with some complementary infrastructure; however, implementation faces possible entry barriers and longer time for construction.

- ✓ The development of major transmission infrastructure is not required, as production is near end users. Infrastructure development is limited to in-basin delivery infrastructure.
- × Solar generation capacity is constrained by land availability, which in turn limits the scale of hydrogen production that can be developed to meet demand. The supply-demand gap is likely to be substantial in the longer term.
- × Land availability for solar generation in L.A. Basin is not contiguous, likely requiring complex integration of electricity production from numerous scattered sites.

Intermodal Transport (Liquid Trucking and Rail)

Assessment: Feasible technology readiness, with some complementary infrastructure; however, implementation faces possible entry barriers and longer time for construction.

- ✓ Trucking and train can both leverage existing infrastructure for more straightforward implementation.

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[111] Transmission Project Development Timelines in California.

[112] The In-Basin Hydrogen Production with Power T&D alternative requires the development of four substations and 308 transformers (Refer to Appendix 7.3.1.2.4 in the Cost Effectiveness Study). In comparison, the Angeles Link scope configuration for Scenario 7 requires the development of two compressor stations (Refer to Appendix 7.3.1.2.1 in the Cost Effectiveness Study).

- × Intermodal transport requires many liquefaction/compression terminals to handle the conversion between gaseous and liquid states, to load trains in a timely manner, and to avoid logistical challenges with loading times.
- × More storage infrastructure is required to support intermodal transport to offset the lack of flexibility in train shipment capacity.

4.3.1.1.5. Scalability

Scalability is assessed on each alternative's potential to support increasing throughput volumes along a conceptual route serving 1.5 Mtpa into L.A. Basin and Central California through third-party production sites such as via SJV, Lancaster, and Blythe. The scale of 1.5 Mtpa and associated delivery routes are defined by Scenario 7 in the Preliminary Routing/Configuration Analysis and the Design Study. Scalability is assessed on a 4-point scale, following the ranking defined in Table 9. This criterion is evaluated for each delivery alternative.

Figure 10 below summarizes each alternative's scalability, followed by a summary of the advantages and challenges for each delivery alternative associated with scalability.

Figure 10: Scalability Assessment Across H_2 Delivery Alternatives

Angeles Link Pipeline System	Gaseous Hydrogen Trucking	Liquid Hydrogen Trucking	Liquid Hydrogen Shipping	Methanol Shipping	Ammonia Shipping	Power T&D With In-Basin Production	Localized Hub	Intermodal Transport (Liquid Trucking and Rail)

High Good Moderate Low

Angeles Link

Assessment: Supports at least 1.5 Mtpa, adaptable to expand volume or extend footprint.

- ✓ Pipelines are highly scalable as they can serve different volumes, with economies of scale, using relatively the same infrastructure.
- ✓ Pipeline delivery fully supports the specified scale of 1.5 Mtpa and is adaptable for expansions or extensions, as hydrogen can be further compressed to increase throughput or transported through a pipeline with a larger diameter.

- × Hydrogen pipelines require large-scale construction from the onset compared to more modular solutions.

Infrastructure key metrics: Refer to the project description in Section 3.1.

Trucking (General)

- × Achieving scale requires significant infrastructure development, including the development of liquefaction/compression terminals, and truck manufacturing capacity.
- × To meet peak power demand, the truck fleet and associated liquefaction/compression infrastructure will need to be oversized, resulting in underutilized infrastructure and many vehicles being parked and idle for much of the year to ensure availability during those peak periods.

Gaseous Hydrogen Trucking

Assessment: Challenging or impractical to scale to 1.5 Mtpa due to infrastructure requirements.

- × Gaseous hydrogen trucking may be a solution for smaller volumes. However, as throughput increases to 1.5 Mtpa, infrastructure and implementation challenges increase due to the number of trucks and the associated compression/loading infrastructure required.

Infrastructure key metrics: To meet maximum daily production, storage and demand requirements for the delivery of 1.5 Mtpa of clean renewable hydrogen, there is a requirement for approximately 12,700 trucks and 3,400 compression and loading terminals across transportation corridors connecting various parts of the value chain: (1) hydrogen production sites; (2) underground storages sites; and (3) demand sites in L.A. Basin and Central California.[113] For reference, 12,700 trucks on the road translates to a chain of trucks that extends

[113] A portion of the clean renewable hydrogen is envisioned to support demand in other parts of Central and Southern California.

127 miles.[114] As demand scales, the need for more trucks and associated infrastructure escalates, impacting traffic routes and making this alternative challenging to scale.

Liquid Hydrogen Trucking

Assessment: Feasible at 1.5 Mtpa but severely challenged by land or other constraints.

- ✓ Liquid hydrogen trucking has a higher capacity to scale than gaseous hydrogen trucking as liquified gas is more energy-dense, requiring a smaller fleet of trucks and loading terminals.
- × Liquid trucking still encounters traffic and infrastructure constraints at higher volumes due to the number of trucks on the road and associated liquefaction infrastructure required.

Infrastructure key metrics: To meet maximum daily production, storage, and demand requirements for the delivery of 1.5 Mtpa of clean renewable hydrogen, there is a requirement for 3,200 trucks and 700 liquefaction and loading terminals[115] across transportation corridors connecting various parts of the value chain: (1) hydrogen productions sites; (2) underground storage sites; and (3) demand sites in L.A. Basin and Central California. For reference, 3,200 trucks on the road translates to a chain of trucks that extends 32 miles.[116] As demand scales, the need for more trucks and associated infrastructure escalates, impacting traffic routes and making this alternative challenging to scale.

Shipping (General)

- ✓ Can be a good large-scale solution for long distance hydrogen delivery.

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[114] The number of loading terminals and trucks required were estimated to meet the maximum daily requirement of hydrogen over a one-year period considering truck capacity, loading bay capacity, loading time, and truck mileage (refer to Appendix 7.3.1.2.2 in the Cost Effectiveness Study for technoeconomic assumptions and Appendix 7.3.1.6 for details on the rationale for above ground storage).
[115] The number of loading terminals and trucks required were estimated to meet the maximum daily requirement of hydrogen over a one-year period considering truck capacity, loading bay capacity, loading time, and truck mileage (refer to Appendix 7.3.1.2.2 in the Cost Effectiveness Study for technoeconomic assumptions and Appendix 7.3.1.6 for details on the rationale for above ground storage).
[116] Ibid

- × Shipping alternatives face land constraints near associated port/terminal locations due to the need for specialized handling facilities and as above-ground storage needs increase in tandem with project scale.

Liquid Hydrogen Shipping

Assessment: Feasible at 1.5 Mtpa but severely challenged by land or other constraints.

- ✓ Liquid hydrogen production can be scaled to the assumed throughput levels to meet projected demand.
- × Liquid hydrogen shipping requires more trips than methanol or ammonia due to lower energy density, making scalability more logistically complex.
- × The development of specialized handling facilities and storage infrastructure is likely to face constraints due to land availability near ports as scale approaches 1.5 Mtpa of throughput.

Infrastructure key metrics: To ship 1.5 Mtpa of liquid hydrogen from Northern California to LA ports, approximately 27 ships making 2,100 round trips a year and more than 600 liquid hydrogen storage vessels (700 tH_2) would be required.[117] Additionally, specialized handling infrastructure such as liquefaction and regasification facilities would be needed for this option.

Methanol Shipping

Assessment: Feasible at 1.5 Mtpa but severely challenged by land or other constraints.

- ✓ Shipping hydrogen as methanol is more efficient than liquid hydrogen, given methanol's higher energy density, in terms of the number of trips and ships required to transport the same quantity of liquid hydrogen.
- × This delivery alternative requires additional infrastructure to convert hydrogen into methanol and revert it back to hydrogen upon delivery.

[117] The number of ships required were estimated to meet the maximum daily requirement of hydrogen over a one-year period considering vessel capacity and distance traveled (refer to Appendix 7.3.1.2.3 in the Cost Effectiveness Study and Appendix 7.3.1.6 for details on the rationale for above ground storage).

- × The development of specialized handling facilities and storage infrastructure is likely to face constraints due to land availability near ports as scale approaches 1.5 Mtpa of throughput.

Infrastructure key metrics: To ship 1.5 Mtpa of hydrogen in the form of methanol requires two tanker ships making 60 round trips a year and more than 600 liquid hydrogen storage facilities (700 tH_2) at the destination terminal.[118] Specialized handling infrastructure like methanol conversion and re-conversion facilities would also be required for this option. Additionally, the need to develop specialized handling infrastructure needed for methanol conversion and reconversion (reforming or cracking) back to hydrogen could complicate the scalability of this alternative.

Ammonia Shipping

Assessment: Challenging or impractical to scale to 1.5 Mtpa due to infrastructure requirements.

- ✓ Similar to the methanol shipping delivery alternative, ammonia benefits from a higher energy density than liquid hydrogen and offers more efficiency in terms of trips, requiring around 100 trips annually[119].
- × This delivery alternative requires additional infrastructure to convert hydrogen into ammonia and revert it back to hydrogen upon delivery.
- × Facilities to synthesize ammonia (as a hydrogen carrier) require continuous operations, which may become challenging as demand scales and because of the constraints of solar power generation as the key resource for power and hydrogen supply for synthesizing ammonia.
- × The development of specialized handling facilities and storage infrastructure is likely to face constraints due to land availability near ports as scale approaches 1.5 Mtpa of throughput.

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[118] The number of trips and ships required were estimated to meet the maximum daily requirement of hydrogen over a one-year period considering vessel capacity and distance traveled (refer to Appendix 7.3.1.2.3 in the Cost Effectiveness Study and Appendix 7.3.1.6 for details on the rationale for above ground storage).

[119] The number of trips required were estimated to meet the average requirement of hydrogen over a one-year period considering vessel capacity and distance traveled (refer to Appendix 7.3.1.2.3 in the Cost Effectiveness Study).

Infrastructure key metrics: To ship 1.5 Mtpa of hydrogen as ammonia would require three ships making 150 round trips a year and more than 600 liquid hydrogen storage vessels (700 tH_2).[120, 121] Additionally, the need to develop specialized handling infrastructure like ammonia conversion and re-conversion (reforming or cracking) back to hydrogen could complicate the scalability of this alternative.

In-Basin Production with Power T&D

Assessment: Challenging or impractical to scale to 1.5 Mtpa due to infrastructure requirements.

- × The lead-time for developing electric system infrastructure could limit the ability to develop infrastructure at the pace required to keep up with demand growth.[122]
- × When scaling to 1.5 Mtpa, significant new electric system infrastructure and land access (18-20 ft width per line)[123] is required to meet power demand.

Infrastructure key metrics: A 500kV AC transmission system was selected in order to meet the capacity requirements for the Delivery Alternative. The 500kV system is largely compatible with the CAISO grid, which is mostly AC. As discussed in the Cost Effectiveness Study (Appendix 7.3.1.2.4), the effective load carrying capacity for a typical 500kV AC transmission system does not exceed 3GW, rapidly declining with the transmitting distance. Hence, supporting 26.6 GW of electricity load requirement (in addition to the 1.8 GW of transmission load losses) for hydrogen production would require multiple transmission lines consisting of 10 double circuit and 1 single circuit transmission system (for a total of 21 circuits) across a 400-mile transmission corridor (accounting for a total of 2,500 miles of transmission). Refer to Appendix 7.2.2 and 7.3.1 (Cost Effectiveness Study) for additional details. In-basin production with power T&D would also require more than 600 liquid hydrogen storage vessels (700 tH_2) for above-ground storage.

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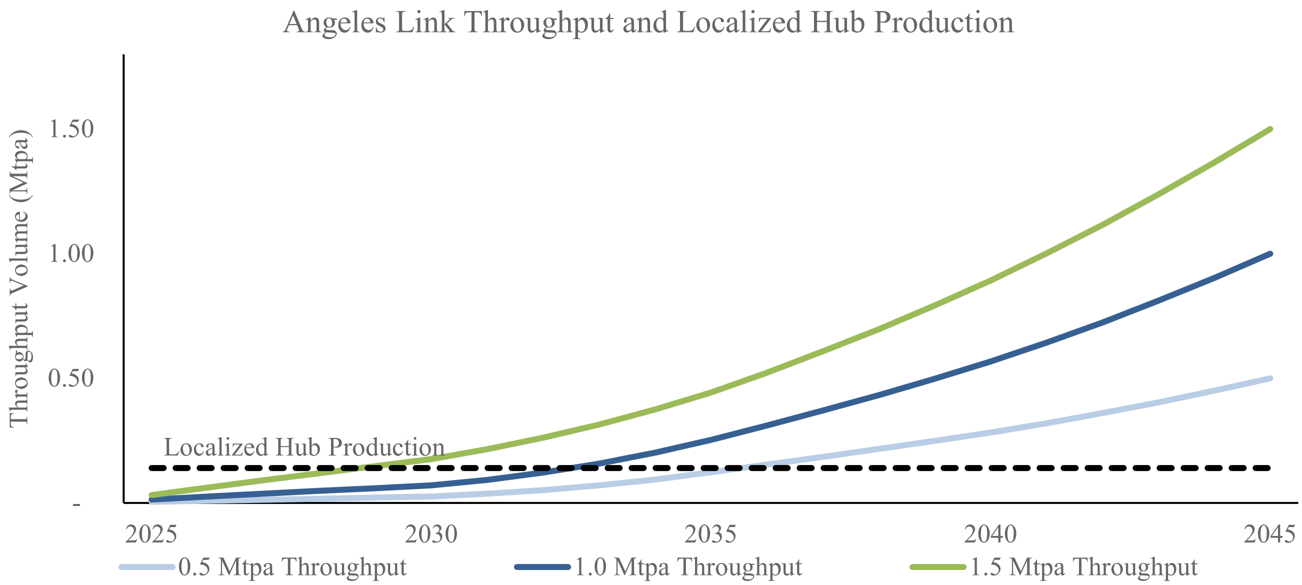
[120] The number of ships required were estimated to meet the maximum daily requirement of hydrogen over a one-year period considering vessel capacity and distance traveled (refer to Appendix 7.3.1.2.3 in the Cost Effectiveness Study and Appendix 7.3.1.6 for details on the rationale for above ground storage).
[121] See the Cost Effectiveness Study for more details on the Methanol Shipping infrastructure requirements.
[122] Transmission Project Development Timelines in California.
[123] Assumes 60 meters (~18 ft) is required for double circuit 500 kV lines and 65 meters (~20 ft) for single circuit 500 kV lines. See Pipelines vs Powerlines: A Technoeconomic Analysis in the Australian Context, Figure 10.

Localized Hub

Assessment: Challenging or impractical to scale to 1.5 Mtpa due to infrastructure requirements.

- × The utility-scale solar potential in the area is 4.4 GW,[124] equating to 0.14 Mtpa of hydrogen production (as shown on Figure 11 below), which is insufficient compared to the throughput range of 0.5-1.5 Mtpa to serve California's decarbonization needs.

Figure 11: Angeles Link Throughput and Localized Hub Production[125]



Infrastructure key metrics: To develop the potential 4.4 GW of solar capacity in L.A. Basin, an estimated 26,400 acres of land is required, which equates to 8% of the LA area.[126] In a case where this land could be acquired and the 4.4 GW of solar generation could be developed, the hydrogen production potential is sub-optimal, reaching just 0.14 Mtpa of hydrogen. Additionally, in-basin hydrogen

[124] Los Angeles Department of Water & Power, Los Angeles 100% Renewable Energy Study (LA100), see: LA100 Study. P.26 "A site development cost ranking analysis of this potential indicates that about 4,400 MW or about 80% of the non-rooftop local solar potential can be built at or below $100/megawatt-hour (MWh) based on 2019 capital costs"

[125] For additional context, please refer to Figure 28: Localized Hub Area Map in Appendix 7.1.1.

[126] Considering 6 acres per MW, see: Land-Use Requirements for Solar Power Plants in the United States (nrel.gov).

production also requires 60 liquid hydrogen storage vessels for the production of 0.14 Mtpa[127] due to the lack of underground storage available in the L.A. Basin.

Intermodal Transport (Liquid Trucking and Rail)

Assessment: Challenging or impractical to scale to 1.5 Mtpa due to infrastructure requirements.

- × As volumes approach 0.5 Mtpa, delivery by train encounters logistical impasses, as hydrogen rail cars would occupy 66%-95%[128] of the on-dock rail available space in the Port of L.A., deeming the port unusable for other commercial activities.
- × This setup demands substantial time to load each tank car. As volumes increase, the necessity for more tank cars grows, making the option impractical at larger volume sizes.

Infrastructure key metrics: The delivery of 1.5 Mtpa of hydrogen by rail would require 900 tank cars daily. [129] Additionally, specialized infrastructure would be required to fill multiple sequentially placed railroad cars with hydrogen at each production location.

4.3.1.2. Dismissed Hydrogen Delivery Alternatives

Ammonia shipping and intermodal transport (liquid trucking and rail) ranked the lowest in the evaluation of alternatives based on the criteria analyzed above, and therefore they were not carried forward for further analysis.

4.3.1.2.1. Ammonia Shipping

Ammonia shipping was initially evaluated but not carried forward for analysis in the Cost Effectiveness Study or Environmental Analysis due to incompatibility with the criteria discussed above. The Haber-Bosch process requires a reliable and continuous supply of electricity and power which is incompatible with the intra-day profile for solar availability as elaborated below:

- **Hydrogen-to-ammonia process requirements:** The process of converting hydrogen to ammonia (known as Haber Bosch ammonia synthesis) requires constant input of hydrogen and power. Ammonia units require several days to start up to reach 250-350 bar of pressure and 450-

[127] Please refer to the Angeles Link High-Level Economic Analysis & Cost Effectiveness Report for more details on the Localized Hub infrastructure requirements.
[128] See 4.3.1.2.2 for additional context.
[129] High-level analysis considering an average day using train cars of 4.5 tons of liquified hydrogen.

600°C of temperature. Once the units are turned on, they have a limited operating utilization range between 60-80%. Large fluctuations in temperatures impact performance and damage the integrity of the catalyst.

- **Project technical parameters:** The Production Study identified solar generation as the most likely power source to meet the CPUC's definition for clean renewable hydrogen production and to serve demand in California.
- **Challenges for solar-to-ammonia production:** Solar power generation is especially incompatible with the ammonia production process due to the intra-day intermittency of its availability (even for solar plus battery energy storage system (BESS) facilities). To meet the constant power input needs of the Haber-Bosch process, it is likely that higher carbon intensity power grid access would be required during the hours when solar or BESS resources are not available. This system configuration is inconsistent with non-grid interconnected renewable power that would be aligned with the CPUC's definition of clean renewable hydrogen.

The incompatibility between the operational requirements of the Haber-Bosch process and the assumption that solar generation would serve as the primary electricity input for clean renewable hydrogen production[130], meant the ammonia shipping alternative was not well suited to meet the criteria for state policy, reliability and resilience, ease of implementation, and scalability. Therefore, this alternative was excluded from further analysis in the Cost Effectiveness Study and the Environmental Analysis.[131]

4.3.1.2.2. Intermodal Transport (Liquid Trucking and Rail)

Rail as a delivery alternative has unique logistical challenges as described below, which deem it incompatible with the criteria applied in this study for the evaluation of delivery alternatives.

[130] The Production Study found that solar capacity was the best resource for renewable electricity generation within the state of California for the production of clean renewable hydrogen. The intra-day availability of solar poses a challenge for the ammonia production process.
[131] Additional considerations regarding ammonia as an alternative can be found in Appendix 7.3.

- **Loading infrastructure requirements:** The system would need between 200-300 loading terminals running 24/7 to fill the rail cars required to deliver 1.5 Mtpa of clean renewable hydrogen.[132]
- **Infrastructure challenges:** On an average day, the system would need to transport approximately 900 rail cars per day, and on a peak production day approximately 1,300, which is equivalent to 7.5 to 10.5 miles of rail cars on the tracks daily.
- **Unloading constraints:** The Port of L.A. consists of approximately 65 miles of on-dock track and has an average dwell time for on-dock rail containers of 5.8 days.[133] This means hydrogen containers would occupy 43-62 miles of the 65 miles available for on-dock rail containers. Hydrogen rail cars would occupy 66%-95% of the on-dock rail available space in the Port of L.A., deeming the port unusable for other commercial activities.

As a result of rail infrastructure constraints described above, and the high emissions associated with the fuels currently used to power trains and trucks, the intermodal transport alternative was not well suited to meet the criteria as defined for state policy, reliability and resilience, ease of implementation, and scalability and was therefore excluded from further analysis in the Cost Effectiveness Study and the Environmental Analysis.

4.3.1.3. Hydrogen Delivery Alternatives Advanced

The Hydrogen Delivery Alternatives noted below were advanced for evaluation in the Cost Effectiveness Study and the Environmental Analysis, as they were determined to meet at least a minimum level of the evaluation criteria.

- Angeles Link Pipeline System
- Liquid Hydrogen Trucking
- Gaseous Hydrogen Trucking
- Liquid Hydrogen Shipping
- Methanol Shipping

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[132] Average and peak day rail car requirements are 900-1300 rail cars. Each bay can load 20 tonnes per day, and a rail car can transport 4.5 tonnes. Accordingly, the loading bays required would be 200 on an average and 300 on a peak day (calculation: 900*4.5/20 to 1,300*4.5/20).
[133] Port of L.A. Operations Reports.

- In-Basin Production with Power T&D
- Localized Hub

4.3.2. Evaluation of Non-Hydrogen Alternatives

Five assessment criteria were applied to evaluate the Non-Hydrogen Alternatives relative to Angeles Link for their suitability to serve as decarbonization pathways for each use case in California and to determine their advancement to the next steps in the analysis: (i) state policy; (ii) reliability and resiliency; (iii) technical maturity; (iv) scalability; and (v) end user requirements, summarized in Table 10 below. A 4-point assessment rubric (high, good, moderate, low) was used to evaluate the extent to which each Non-Hydrogen Alternative may achieve or be consistent with each criterion.

Table 10: Non-Hydrogen Alternatives Assessment Criteria

Criteria Selected for Screening	Definition	High	Good	Moderate	Low
State Policy	Level of alignment with California's clean energy and environmental policies	Alignment with state policy, including specific mandates or incentives	Alignment with state policy but potential conflicts with decarbonization goals	No alignment with state policy and potential conflicts with decarbonization goals	Explicit misalignment with state policy and conflicts with decarbonization goals
Reliability & Resiliency	Contribution to both use case-level and energy system-level reliability and resiliency	Notable improvement of user and/or system reliability and resiliency.	No/minimal benefits/risks relative to business as usual (BAU) user and/or system reliability and resiliency	Unclear or moderate risk of disruption to user and/or system reliability and resiliency	Likely disruption to user and/or system reliability and resiliency
Technical Maturity	Likelihood of achieving widespread commercial availability by 2030[134]	Commercially available and widespread	Commercially available but limited in deployment	Pilot stage	Lab stage
Scalability	Likelihood of full value chain ability to support large-scale deployment by 2030 (up/mid/downstream)	Robust current value chain; minimal risks to scalability	Minimal potential risks to scalability in the value chain	Multiple potential risks to scalability in the value chain (but addressable)	High risk somewhere in the value chain to prevent scalability
End-User Requirements	Ability to support the full set of end-user requirements in a way that supports decarbonization with minimal impact on operations and business models	Strong ability to serve end-user requirements; clear path to implement	Minimal disruption to operations and/or business models	Material disruption to operations and/or business models (but addressable)	High risk in serving a key end-user requirement

Because the use cases relevant to electrification and CCS differ, each alternative is evaluated below in comparison to Angeles Link across relevant sectors and use cases.

[134] 2030 is used as technology development beyond this date is difficult to predict. This is partly informed by the Technology Readiness Levels (TRLs) published by the International Energy Agency. See Appendix 7.4.1 for additional detail on the TRL scores.

4.3.2.1. Electrification

For the electrification use cases, analysis was conducted to understand where it may be possible for end users to electrify in lieu of using clean renewable hydrogen or traditional fuels and what changes end users might have to implement to make that change. The assessment of electrification was conducted primarily on a use case level (e.g., FCEV vs. BEV for heavy-duty vehicles (HDVs)), and certain system-level considerations and assumptions, such as the T&D infrastructure required to deliver the electricity for consumption by the end user, are incorporated into the use case level assessments where relevant. A broader analysis of system-level electrification considerations was also conducted based on a high-level review of existing research, third-party studies, and California policy. These system-level electrification considerations are summarized below, with additional details in Appendix 7.3.3.

4.3.2.1.1. System-Level Electrification Considerations

System-level electrification considerations include impacts across the electricity system value chain, such as electricity demand, generation supply to meet the demand, and supporting electric transmission and distribution infrastructure. Appendix 7.3.3 provides an in-depth exploration of system electrification, presenting literature reviews, examining critical implications throughout the electrification value chain, and discussing key findings. Key findings from the high-level review of these considerations include the following:

- **Demand considerations**: Electrification is widely recognized as a primary decarbonization pathway for many sectors, including light-duty vehicles and residential and commercial heating, but it is also known to be less technically feasible in hard-to-electrify sectors like heavy-duty transportation and high-heat industrial processes.[135]
- **Supply considerations**: Wind, solar, and battery storage are being deployed at scale, but there remains a need for clean firm generation and long duration storage in the power system to ensure reliability.[136] The industry-accepted approach to determine how supply portfolios meet demand and ensure power system reliability is power flow modelling analysis to determine the necessary infrastructure capacity expansion, system interconnections, and system operational requirements.

[135] Discussed in the demand section of Appendix 7.3.3.
[136] EDF, California needs clean firm power, and so does the rest of the world.

- **Electric T&D infrastructure considerations**: The electricity system requires substantial investment in new T&D infrastructure to accommodate planned increases in electric generation and load growth. The additional infrastructure needed to support a higher level of electrification of the use cases supported by Angeles Link would be incremental and would increase the burden on already ambitious power T&D investment plans as detailed by the CPUC Integrated Resource Plan (IRP)[137] and CAISO.[138]

4.3.2.1.2. Use Case Level Electrification Evaluation

Angeles Link is assessed relative to electrification in specific use cases across the priority sectors identified in the Demand Study. Details of the four use case assessments are below, comparing Angeles Link to electrification across the following applications:

- **Mobility**: FCEV as compared to BEV for long-haul, heavy-duty applications
- **Power**: Hydrogen-fueled combustion plant as compared to battery energy storage facility for peaking and reliability needs
- **Food & Beverage**: Hydrogen-fueled ovens/fryers as compared to electric ovens/fryers
- **Cement**: Hydrogen-fueled kilns as compared to electric kilns

4.3.2.1.2.1. Mobility

In the mobility sector, FCEVs were identified as the end use application for hydrogen supplied by Angeles Link, while BEVs were identified as the end use application for electrification. Specifically, both FCEVs and BEVs were evaluated for the four primary long-haul, heavy-duty applications described in the Demand Study as having the greatest hydrogen adoption potential due to their operational requirements: transit buses, sleeper cabs, day cabs and drayage trucks. Figure 12 shows an assessment of FCEVs and BEVs in the mobility sector.

[137] California Public Utilities Commission IRP.
[138] California ISO. (2023). CAISO 2022-2023 Transmission Plan.

Figure 12: Evaluation: Mobility (FCEV and BEV)

Alternative	Technology Application	Mobility Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements
Angeles Link	Fuel Cell Electric Vehicle	• Transit Bus • Drayage • Sleeper Cab • Day Cab					
Electrification	Battery Electric Vehicle						

High Good Moderate Low

- **State Policy. Both clean renewable hydrogen and electrification are strongly aligned with state policy supporting mobility decarbonization.**
  Adoption of FCEVs and BEVs is strongly aligned with California regulations and incentives targeting the decarbonization of HDVs and fleets by 2045. The primary state policy drivers for HDV decarbonization are the Advanced Clean Fleet and the Advanced Clean Trucks regulations, which mandate transitioning to zero emission vehicles (ZEVs), for which both FCEVs and BEVs qualify.[139]
- **Reliability & Resiliency. Clean renewable hydrogen is advantaged due to long-duration molecule storage.**
  FCEVs offer a reliability and resiliency advantage compared to BEVs due to the advantage molecules have over electrons to meet long-term storage requirements.[140] Fleet-based BEVs face a disadvantage in siting charging stations due to the importance of locating stations in areas that have enough electrical distribution capacity. BEVs may also face demand response actions (such as those under the CPUC's Emergency Load Reduction Program for EVs) that restrict charging during peak demand periods, unlike FCEVs which are exempt from such constraints.
- **Technical Maturity. Though not yet widespread currently, both clean renewable hydrogen and electrification technologies are ready to serve the heavy-duty transport sector.**

[139] California Air Resources Board Advanced Clean Fleet and Advanced Clean Truck regulations.
[140] Typically 2-4 days of hydrogen is stored onsite at refueling stations (according to a pilot project run in Kentucky), while typical battery durations last between 4-8 hours.

On the IEA's technology readiness scale,[141] FCEVs and BEVs score nine, indicating both technologies are in commercial deployment in select markets. However, FCEVs and BEVs have not yet achieved widespread adoption to serve the heavy-duty vehicle segment, with BEV adoption outpacing FCEVs due to the more prevalent charging infrastructure available today. According to the California Energy Commission (CEC), there are over 100 FCEV buses and Class 8 trucks on the road as of 2023, while the number of BEV buses and Class 8 trucks operating on California roads exceeds 1,200.[142]

- **Scalability. Although clean renewable hydrogen and electrification are scalable solutions in the mobility sector, both face important challenges across the value chain which must be addressed to achieve scale.**
  While there is interest among original equipment manufacturers (OEMs) to scale FCEV and BEV manufacturing, scalability challenges for these solutions are primarily due to the availability of supporting infrastructure. Hydrogen requires key elements across the value chain to scale, including water availability, electrolyzer supply, and new delivery and storage infrastructure. BEV requirements to scale include strengthening transmission and distribution infrastructure, supply chain risks around vehicle battery raw materials, transformers and other charging infrastructure equipment, and land availability for siting of new electrical capacity.
- **End-User Requirements. Clean renewable hydrogen is advantaged due to the operational requirements met by FCEV technology for heavy-duty, long-range, fast-refueling applications.**
  FCEVs offer a natural advantage to fleet operators as drivers spend comparable times to refuel relative to current technology.[143] For BEVs, fleet operators may need to accommodate new business models, new charging/refueling patterns, longer charging/refuelling times, and potentially increased investment in additional vehicles due to decreased payload.[144] These issues are discussed in greater detail in the Demand Study.

[141] IEA's framework identifies the solutions that exist today and rank their readiness along an extended "Technology Readiness Level" (TRL) scale covering concept stage to scaling up the technology solution.
[142] California Energy Commission – Zero Emission Vehicle and Infrastructure Statistics.
[143] UC Davis, ITS Hydrogen Study: California FCEV and Hydrogen Refueling Station Deployment: Requirements and Costs to 2050 (escholarship.org).
[144] Payload refers to the maximum amount of weight that can be safely added to a truck's cargo area in addition to its own weight with no cargo.

4.3.2.1.2.2. Power

Both clean renewable hydrogen and electrification are potential alternatives to support power generation. Hydrogen can be used in fuel cells or combusted using a turbine. For the purpose of this study, hydrogen-fueled combustion plants were identified as the end use application for hydrogen supplied by Angeles Link. Batteries are typically used to store electricity for discharge at a later time of need. For the purpose of this study, lithium-ion battery energy storage facilities were identified as the end use application for electrification.

With an increasing share of renewables displacing gas generation in California, clean firm generation and LDES resources are needed to balance the shortfall in renewables output. As a result, this study considered a 12-hour Lithium-ion battery storage "stack" as the most reasonable comparison to a hydrogen-fueled power plant.[145] Other LDES technologies, like compressed air energy storage (CAES) and vanadium redox flow batteries (VRFB), are emerging and may serve as better candidates for LDES than lithium-ion in the long run, but they were not deemed mature enough for further discussion in this study.

There are few decarbonization options that can play the diversity of roles that hydrogen can in the power system. This is discussed further in Appendix 7.3.3 and 7.3.4 on system-level electrification and the selection of 12-hour lithium-ion battery storage for the power use case. Figure 13 shows an assessment of hydrogen power plants and battery energy storage facilities in the power sector.

Figure 13: Evaluation: Power (Hydrogen Combustion Plants and Battery Storage)

Alternative	Technology Application	Power Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements
Angeles Link	Hydrogen Combustion Turbine	Low Capacity Factor / Reliability Units	High	High	Moderate	Moderate	Good
Electrification	12-hr Battery Storage		High	Good	Good	Good	Moderate

High Good Moderate Low

- **State Policy. Clean renewable hydrogen and electrification are strongly aligned with state and local policies driving decarbonization of the power sector.**

[145] See Appendix 7.3.4 for the rationale for selection of 12-hour Lithium-ion battery storage as a reasonable comparison.

Both clean renewable hydrogen to support power generation and battery storage resources help advance California's key policy goals, including SB 100, California's landmark policy requiring renewable energy and zero-carbon resources supply 100 percent of electric retail sales to end-use customers by 2045, and LA100, L.A.'s plan to transition to 100% clean energy by 2035.[146] Standalone battery storage does not qualify for the State's renewables portfolio standard (RPS) targets due to the inability to determine the power stored and dispatched is renewable unless directly connected to an otherwise qualifying renewable facility.[147]

- **Reliability & Resiliency. Hydrogen turbines supplied by Angeles Link are advantaged due to their ability to address seasonal and multi-day power system needs.**
  Hydrogen has a natural advantage over battery storage due to its ability to store energy and use it to generate firm dispatchable electricity, including seasonal balancing and multi-day dispatch (e.g., during extreme weather).[148] Current battery technologies have a storage duration of 2-4 hours or up to 8 hours when stacked. While battery storage has a role to play in power system reliability and can address shorter duration events, to meet needs of long duration storage, lithium-ion facilities would have to be significantly oversized. Hydrogen and battery storage can play important but likely distinct roles to provide grid services and support reliability of the California power system.
- **Technical Maturity. Clean renewable hydrogen is less technically mature compared to electrification as lithium-ion battery technology is currently more mature than 100% hydrogen-capable turbines.**
  Lithium-ion technology scores 10 on the IEA technology readiness scale, representing commercial deployment at scale. Lithium-ion battery storage offers a commercially available and mature solution that can be stacked, however uneconomically, to achieve longer durations of storage (e.g., up to 12 hours).[149] Turbines that run on unblended hydrogen score seven, indicating pre-commercial demonstration.[150] 100% hydrogen-capable turbines are under

[146] Although renewable hydrogen and battery storage do not qualify under the list of "eligible fuels" under SB 100, the policy leaves a provision for 40% of CA's generation to come from other "zero-carbon polluting resources."
[147] RPS Guidebook.
[148] EDF, California needs clean firm power, and so does the rest of the world.
[149] California Energy Commission. Retrieved from Assessing the Value of Long-Duration Energy Storage in California.
[150] This is partly informed by the Technology Readiness Levels (TRLs) published by the International Energy Agency. See Appendix 7.4.1 for additional detail on the TRL scores.

development globally with Tier 1 OEMs and are expected to be commercially available by 2030.[151]

- **Scalability. Clean renewable hydrogen is less scalable versus electrification since battery energy storage is a modular technology, meaning there are fewer challenges to scale across the value chain.**
  From an end-use case perspective, hydrogen combustion plants require key elements across the value chain to scale, including water availability, electrolyzer supply, and new transport and storage infrastructure. Battery storage could offer a modular solution to meet specific power system requirements, but it faces raw material supply chain constraints, siting and interconnection delays, and would require significant deployment to reach the scale possible with seasonal storage of hydrogen.
- **End-User Requirements. Clean renewable hydrogen is advantaged due to the unique set of roles it can play in the power system and the ability to retrofit existing gas plants.**
  Hydrogen turbines can play a strategic role in the power system as both clean firm generation and as a longer-duration reliability resource and can be dispatched like a baseload unit[152] or a peaker power plant[153] catering to peak loads. Hydrogen turbines can also be introduced as a retrofit to current natural gas power plants, like Los Angeles Department of Water and Power's (LADWP) Scattergood plant,[154] some of which are strategically located for local reliability. Battery storage can also play a diverse but different role (primarily grid services, shaping of renewables, and shorter-duration reliability needs), and would require new-build facilities.

4.3.2.1.2.3. Industrial – Food & Beverage

In the food & beverage (F&B) sector, clean renewable hydrogen-fueled or electrically powered ovens and fryers could be used to decarbonize operations. Both hydrogen delivered via Angeles Link, and electrification may be able to serve additional needs of the diverse food & beverage sector, however this

[151] Angeles Link Demand Study.
[152] The term "baseload power" refers to the minimum quantity of electricity required to supply the electrical grid at any given time, see: Baseload power - Energy Education.
[153] Supplement other types of power plants and operate during peak power demand periods, such as hot summer afternoons, see: Electricity: Information on Peak Demand Power Plants | U.S. GAO.
[154] LADWP Scattergood Modernization Project.

direct technology comparison was deemed most insightful for purposes of this Phase 1 study. Figure 14 compares hydrogen and electric ovens and fryers in the F&B sector.

Figure 14: Evaluation: Food & Beverage (Hydrogen-Fueled and Electric Ovens and Fryers)

Alternative	Technology Application	Food and Beverage Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements
Angeles Link	Hydrogen Ovens/Fryers	Low Process Heating Application					.
Electrification	Electric Ovens/Fryers						

High Good Moderate Low

- **State Policy. Clean renewable hydrogen must be able to address the regulation of NOx emissions in the F&B sector.**
  While there are few major state policies targeting decarbonization in the F&B sector, a rule by the South Coast Air Quality Management District (AQMD) subjects commercial food ovens to a future zero-emission standard, specifically targeting NOx.[155] Hydrogen combustion bears a greater compliance risk due to potential for NOx emissions. Additional details on NOx emissions can be found in the Angeles Link NOx Study.
- **Reliability & Resiliency. Clean renewable hydrogen is advantaged due to long-duration molecule storage.**
  From a use case level perspective, Angeles Link offers a reliability and resiliency advantage compared to electrification due to the advantage molecules have over electrons to meet long-term storage requirements. Electrification also faces a slight disadvantage of adding load to an already strained grid, although incremental electrification in the F&B sector is expected to be relatively small compared to other industrial loads.
- **Technical Maturity. Clean renewable hydrogen is less technically mature than electrification given the more widespread commercial availability of electric equipment in the F&B sector.**

[155] Rule-1153.1. South Coast Air Quality Management District NOx emissions regulation.

For low temperature heating applications that would be applicable in food and beverage equipment such as ovens and fryers, hydrogen and electrification have a TRL score of nine, representing different stages of market uptake in select environments.[156] For the food and beverage industry particularly, a wide range of electric equipment, including fryers and ovens, are commercially available in the market today. However, hydrogen fueled equipment, while commercially available for certain applications such as baking ovens, is not widespread enough to cover the diverse set of equipment needed to fully decarbonize the sector.

- **Scalability. Clean renewable hydrogen is disadvantaged as electrification can leverage existing electric grid infrastructure.**
  Scaling hydrogen equipment in the F&B sector would require a robust hydrogen delivery infrastructure that sustains reliable hydrogen supply to food and beverage facilities. Obstacles to scale for electrification in the F&B sector could be influenced by the need to strengthen transmission and distribution infrastructure to accommodate any increased electricity demand.
- **End-User Requirements. Both clean renewable hydrogen and electrification require new equipment but can meet end-users' needs.**
  Hydrogen and electrification require new equipment investment from facility owners to upgrade their ovens and fryers, potentially resulting in temporary business disruptions. However, these challenges are considered minor.

4.3.2.1.2.4. Industrial – Cement

Clean renewable hydrogen and electrification can support decarbonization of high process heating associated with cement kilns, which are typically the second-largest source of cement facility emissions following clinker production. Clinker production emissions are intrinsic to the chemical calcination process and are not addressable by hydrogen or electricity. For the purpose of this study, hydrogen-fueled kilns were identified as the use case application for Angeles Link, while electric kilns were identified as the use case application for electrification. Figure 15 compares hydrogen and electric kilns in the cement sector.

[156] This is partly informed by the Technology Readiness Levels (TRLs) published by the International Energy Agency. See Appendix 7.4.1 for additional detail on the TRL scores.

Figure 15: Evaluation: Cement (Hydrogen-Fueled and Electric Kilns)

Alternative	Technology Application	Cement Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements
Angeles Link	Hydrogen Kiln	High Process Heating Application					
Electrification	Electric Kiln						

High Good Moderate Low

- **State Policy. Both clean renewable hydrogen and electrification are strongly aligned with state policy driving decarbonization of the cement industry.**
  Hydrogen-fueled and electric kilns can support the cement industry's decarbonization in line with SB 596, which requires cement producers to reduce their GHG emissions by 40% below 1990 levels by 2030, achieving net-zero by 2045.[157]
- **Reliability & Resiliency. Clean renewable hydrogen is advantaged due to long-duration molecule storage.**
  Clean renewable hydrogen offers a reliability and resiliency advantage compared to electrification due to the advantage molecules have over electrons to meet long-term storage requirements. Electrification also adds load to an already strained grid, and this could be a concern for large loads running at high load factors like electric kilns.
- **Technical Maturity. Both clean renewable hydrogen and electric kilns are in the large-scale pilot stage.**
  Hydrogen-fueled and electric kilns have achieved a rating of five on the IEA's TRL scale, signifying that both options are presently undergoing pilot testing.[158] Four hydrogen kiln projects were recently announced by Cemex in Mexico.[159] Several kiln manufacturers are also exploring electrification, with Coolbrook's RotoDynamic Reactor technology being used in several large-scale pilot projects.[160]

[157] Net-Zero Emissions Strategy for the Cement Sector | California Air Resources Board.
[158] This is partly informed by the Technology Readiness Levels (TRLs) published by the International Energy Agency. See Appendix 7.4.1 for additional detail on the TRL scores.
[159] Cemex Mexico Future in Action Program.
[160] CoolBrook Electric cracking.

- **Scalability. Clean renewable hydrogen and electric kilns are scalable solutions for the cement sector, but both also face challenges to achieve that scale.**
  Scaling hydrogen equipment in the cement sector will require a robust hydrogen infrastructure that maintains reliable hydrogen supply to cement facilities. Requirements for scale for electrification in the cement sector include the need to strengthen power distribution infrastructure to accommodate any increased electricity demand, which could be significant for large loads running at high load factors like electric kilns.
- **End-User Requirements. Cement kilns driven by clean renewable hydrogen and electrification both require new equipment but can meet end-users' needs.**
  Both hydrogen kilns and electric kilns require investment in new equipment from facility owners to transition to zero-carbon cement processing, which could result in business disruptions.

4.3.2.2. CCS

CCS is an alternative decarbonization pathway across several sectors and can be applied where natural gas is used today. Assessment of CCS was conducted on a use case level (e.g., hydrogen combustion turbines vs. gas combustion turbines with CCS for the power generation sector), and certain system-level considerations and assumptions, such as the CO_2 transport and sequestration infrastructure required to enable carbon management for end users, are incorporated into the use case level assessments.

4.3.2.2.1. Use Case Level CCS Evaluation

Angeles Link is assessed relative to CCS based on specific use cases across the priority sectors identified in the Demand Study. A comparison of Angeles Link and CCS across the four use case assessments is provided below.

- **Power**: Hydrogen-fueled combustion plant vs. natural gas-fueled combustion plant with CCS
- **Cogeneration**: Hydrogen-fueled cogeneration facility vs. natural gas-fueled cogeneration facility with CCS
- **Cement**: Hydrogen-fueled kilns vs. natural gas-fueled kilns with CCS
- **Refineries**: Angeles Link-delivered clean renewable hydrogen for refinery process needs vs. conversion of current unabated hydrogen (derived from fossil fuels), supply to abated hydrogen

(low-carbon) via addition of CCS to existing natural gas-fueled steam methane reformers (SMRs)

4.3.2.2.1.1. Power and Cogeneration

Given similarities in applications and considerations, the power and cogeneration sectors are presented together. The existing natural gas power and cogeneration fleet presents an opportunity for decarbonization through either hydrogen turbine retrofits or carbon capture retrofits. In both sectors, a hydrogen-fueled combustion facility is assumed to utilize the hydrogen delivered from Angeles Link, and CCS is assessed based on a natural gas-fueled combustion facility retrofitted with CCS. Figure 16 compares Angeles Link with CCS in the power and cogeneration sectors.

Figure 16: Evaluation: Power and Cogeneration (Hydrogen Combustion Plants and Natural Gas Plants with CCS)

Alternative	Technology Application	Power Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements
Angeles Link	Hydrogen Combustion Turbine	High Capacity Factor / Baseload Units	High	High	Moderate	Moderate	Good
CCS	Gas Turbine with CCS		Good	Good	Moderate	Moderate	Moderate

High Good Moderate Low

Alternative	Technology Application	Cogeneration Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements
Angeles Link	Hydrogen Combustion Turbine	Cogen Units (Typically Dispatched as Baseload)	High	High	Moderate	Moderate	Good
CCS	Gas Turbine with CCS		Good	Good	Moderate	Good	Good

High Good Moderate Low

- **State Policy. Hydrogen turbines are advantaged due to more specific incentives.** Both Angeles Link and CCS meet key California and local policy goals. Although neither hydrogen nor CCS are considered under the list of eligible fuels for SB 100, the policy leaves a provision for 40% of California's generation to come from "zero-carbon polluting resources," where hydrogen and CCS can play a role.[161] CCS facilities do not qualify for the State's RPS targets as they are not considered renewable.

- **Reliability & Resiliency. Hydrogen turbines are advantaged due to having a single energy ecosystem (hydrogen) vs. two (gas and CO_2) plus the complexity of multiple system integrations.**
  Angeles Link can enable the development of a long-duration storage capability to support reliability and resiliency of the power and cogeneration sectors. When compared to clean renewable hydrogen, CCS could potentially introduce additional infrastructure development and operational challenges when tasked with capturing and aggregating point source CO_2 emissions from power generation facilities dispersed throughout Central and Southern California.
- **Technical Maturity. Both hydrogen turbines and CCS solutions are in similar stages of technology readiness.**
  On the IEA's TRL scale, hydrogen turbines score seven, while CCS scores eight, which signifies that both technologies are close to commercial operations.[162] 100% hydrogen-capable turbines are under development with Tier 1 OEMs and are expected to be commercially available by 2030.[163] CCS solutions are in various stages of demonstration globally and are expected to be commercially available in a similar time frame as hydrogen turbines.
- **Scalability. Both hydrogen turbines and CCS face similar scaling challenges in the power sector, while proximity to industrial clusters offers CCS an advantage in cogeneration applications.**
  From an end-use case perspective, hydrogen combustion plants require key elements across the value chain in order to scale, including water availability, electrolyzer supply, and permitting of new transport and storage infrastructure. Requirements to scale for CCS solutions include the integration of multiple point sources for large scale CO_2 transport and sequestration infrastructure buildout particularly in the power sector (as gas power plant capacity factors are expected to decline over time, this reduces the scale benefits of CO_2 infrastructure).

[161] SB100 Joint Agency Report.
[162] This is partly informed by the Technology Readiness Levels (TRLs) published by the International Energy Agency. See Appendix 7.4.1 for additional detail on the TRL scores.
[163] Angeles Link Demand Study.

Cogeneration facilities operate at high capacity factors and are typically co-located with industrial clusters where they can benefit from the scale of CCS opportunities at these clusters.

- **End-User Requirements. Hydrogen turbines are advantaged in the power sector due to the relative ease of turbine retrofits vs. CCS retrofits, while proximity to industrial clusters brings CCS back to parity in cogeneration applications.**
  In the power sector, existing gas plants can be retrofitted with either new hydrogen turbines or carbon capture equipment, although the impact on operations and business disruption risk is significant for the balance of plant and operational changes required for carbon capture and integration with CO_2 transport infrastructure. In the cogeneration sector, the operational and business disruption risk is mitigated by the proximity of most cogeneration units in the region to refineries, where the cogeneration units can benefit from the larger scale and diversity of opportunities for CCS in the refinery sector.

4.3.2.2.1.2. Industrial – Cement

Cement facilities can be decarbonized through (among other solutions) hydrogen kiln retrofits or carbon capture retrofits. For the purpose of this study, a hydrogen-fueled kiln is assumed to utilize clean renewable hydrogen delivered from Angeles Link, and CCS is assessed based on a natural gas-fueled kiln retrofitted with CCS. This assessment is primarily focused on decarbonization of the kiln, which is the portion of the cement process for which hydrogen is best suited and is typically the second-largest source of emissions in a cement facility. CCS has the potential to address a range of emissions sources within a cement facility, including clinker production, which is the largest contributor to cement emissions. Figure 17 compares Angeles Link with CCS in the cement sector.

Figure 17: Evaluation: Cement (Hydrogen-Fueled Kilns and Gas Kilns with CCS)

Alternative	Technology Application	Cement Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements
Angeles Link	Hydrogen Kiln	High Process Heating Application					
CCS	Gas Kiln with CCS						

High Good Moderate Low

- **State Policy. Hydrogen kilns and gas kilns with CCS are both well-equipped to support decarbonization of the cement sector.**

  Both Angeles Link and CCS can support cement producers in meeting SB 596 targets, which require cement producers to reduce GHG emissions by 40% below 1990 levels by 2030, achieving net-zero by 2045. However, there is ongoing work at the federal and state level[164] to develop safety regulations regarding the transport and sequestration of CO_2, which presents temporary policy uncertainty for the development of a broader CO_2 infrastructure in California. CCS retrofits have the potential to address a larger share of facility emissions beyond the kiln.

- **Reliability & Resiliency. Hydrogen kilns are advantaged due to having a single system (hydrogen) vs. two (gas and CO_2) with the complexity of multiple system integrations.**

  Angeles Link can enable the development of a long-duration storage capability to support reliability and resiliency of supply to the cement sector. CCS could introduce infrastructure development and operational challenges associated with the integration of both gas and CO_2 transportation and storage networks.

- **Technical Maturity. Hydrogen kilns and gas kilns with CCS are in the same stage of technology readiness.**

  According to the IEA's TRL scale, hydrogen kilns achieve a score of five, while various capture technologies in the cement industry range between five and seven, indicating their respective stages of demonstration projects.[165] Hydrogen combustion kilns are currently in pilot stage as of the date of this study, with four projects recently announced by Cemex in Mexico. A CCS project is also in pilot stage in Canada demonstrating the first full-scale application of CCS for the cement sector, a joint venture between Heidelberg and Mitsubishi.[166]

- **Scalability. Hydrogen kilns face greater scaling challenges in the cement sector.**

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[164] See SB 905, which directs CARB to establish a regulatory framework for the deployment of CCS in California, and new CO_2 pipeline safety measures under development by the Pipeline and Hazardous Materials Safety Administration (PHMSA). More information available at PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak | PHMSA (dot.gov).

[165] This is partly informed by the Technology Readiness Levels (TRLs) published by the International Energy Agency. See Appendix 7.4.1 for additional detail on the TRL scores.

[166] Mitsubishi Heavy Industries – Edmonton CCUS Project

From an end-use case perspective, hydrogen kilns require key elements across the value chain in order to scale, including water availability, electrolyzer supply, and permitting of new transport and storage infrastructure. Requirements to scale for CCS solutions include similar considerations for transport and sequestration infrastructure; however, the proximity of many cement facilities in Kern County to the refinery ecosystem and potential CO_2 storage sites that have been announced may mitigate integration concerns as the connective carbon management infrastructure is developed.

- **End-User Requirements. CCS offers the potential to address a larger share of cement facility emissions.**
  Both hydrogen and CCS retrofits require investment in new equipment, which comes with some operational and business disruption risk. CCS retrofits have the potential to address a larger share of facility emissions beyond the kiln.

4.3.2.2.1.3. Industrial – Refineries

The refineries operating in Central and Southern California are concentrated near the Port of Los Angeles and in the SJV. These refineries currently use unabated hydrogen for operations like hydrocracking and sulphur removal. The advancement of the energy transition and demand for fossil fuels and clean alternatives like renewable diesel will determine the future utilization rates of refineries and their decarbonization efforts. In the refinery sector, clean renewable hydrogen is assumed to be delivered by Angeles Link for the refinery process needs mentioned above, and CCS is evaluated based on the conversion of current unabated hydrogen supply[167] to abated hydrogen (decarbonized hydrogen) via the addition of CCS to existing natural gas-fueled SMRs. The Alternatives Study does not address other refinery emission sources. Figure 18 compares Angeles Link with CCS in refineries.

[167] Unabated hydrogen supply refers to hydrogen produced using natural gas-fueled steam methane reformers, which produce CO_2 emissions.

Figure 18: Evaluation: Refineries (Clean Renewable Hydrogen and Low-Carbon Hydrogen with CCS)

Alternative	Technology Application	Refinery Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements
Angeles Link	Clean Renewable Hydrogen	Fuel Switching					
CCS	Low-Carbon Hydrogen						

High Good Moderate Low

- **State Policy. Both clean renewable hydrogen and CCS score the same due to the absence of refinery-specific decarbonization policies.**
  While there are no refinery-specific decarbonization targets in California policy, both Angeles Link and CCS can support refinery participation in other incentives like the Low-Carbon Fuel Standard. There is ongoing work at the federal and state level to develop safety regulations regarding the transport and sequestration of CO_2,[168] which presents temporary policy uncertainty for the development of a broader CO_2 infrastructure in California.
- **Reliability & Resiliency. Clean renewable hydrogen benefits due to the advantage of having a single system (hydrogen) vs. two (gas and CO_2) with the complexity of multiple system integrations.**
  Angeles Link is intended as an integrated, open access system, providing an inherent long-duration storage capability to support reliability and resiliency of supply to the refinery sector. CCS could introduce infrastructure development and operational challenges associated with the integration of both natural gas and CO_2 transportation and storage networks.
- **Technical Maturity. Clean renewable hydrogen and CCS in refineries are in the same stage of technology readiness.**

[168] See SB 905, which directs CARB to establish a regulatory framework for the deployment of CCS in California, and new CO_2 pipeline safety measures under development by the Pipeline and Hazardous Materials Safety Administration (PHMSA). More information available at PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak | PHMSA (dot.gov).

Both hydrogen and CCS in the refinery sector are in small-scale pilot/demonstration stage (CCS scores four on the IEA TRL scale).[169] Clean renewable hydrogen projects are in pilot/demonstration stages at refineries in China, and CCS solutions are being demonstrated at refineries in Sweden and Norway.[170]

- **Scalability. Clean renewable hydrogen is at a slight disadvantage due to the role of the refinery ecosystem in driving scale needed for higher utilization of CO_2 transport and sequestration infrastructure.**
  Hydrogen requires key elements across the value chain to scale, including water availability, electrolyzer supply, and permitting of new transport and storage infrastructure. Requirements to scale for CCS solutions include similar considerations for transport and sequestration infrastructure, but refineries can serve as anchor customers to provide scale needed to drive utilization of CO_2 transport and sequestration infrastructure.
- **End-User Requirements. Clean renewable hydrogen faces challenges due to the ability of CCS to integrate with existing unabated hydrogen supply.**
  CCS retrofits require investment in new equipment for unabated hydrogen suppliers, which comes with some operational and business disruption risk. Angeles Link could displace existing onsite and/or near site grey hydrogen supply, but adoption may be limited by the ability to replace existing long-term supply contracts in place with refineries.

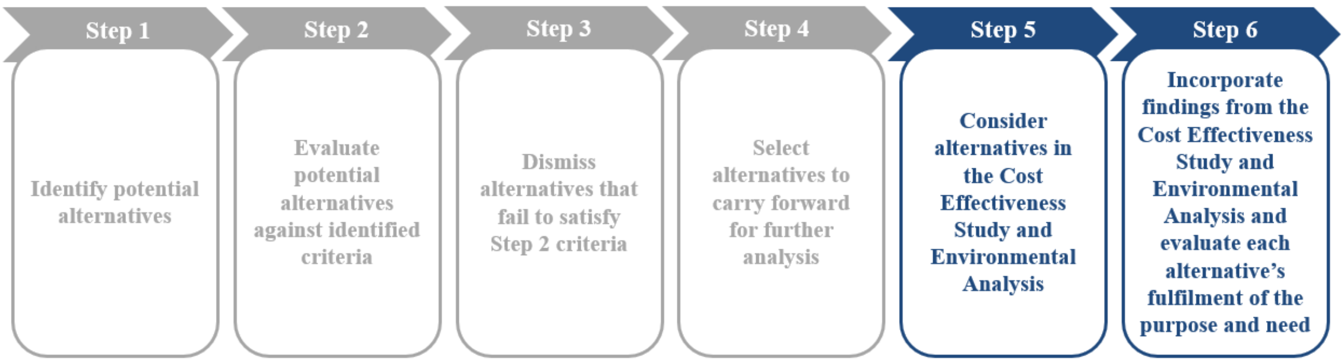
4.3.2.3. Non-Hydrogen Alternatives Advanced

After applying the evaluation criteria described above, both electrification and CCS were deemed appropriate to move forward to the Cost Effectiveness Study and the Environmental Analysis.

[169] This is partly informed by the Technology Readiness Levels (TRLs) published by the International Energy Agency. See Appendix 7.4.1 for additional detail on the TRL scores.
[170] Ibid.

4.4. Cost Effectiveness, Environmental Analysis, and Purpose and Need Assessment

Figure 19: Six-Step Evaluation Process: Cost-Effectiveness and Environmental Analysis Findings and Purpose and Need Assessment



This section summarizes the incorporation of findings from the Cost Effectiveness Study and Environmental Analysis and evaluates the alternatives' fulfillment of Angeles Link's purpose and need as part of the six-step process.

4.4.1. Potential Environmental Impacts

A high-level analysis of the potential environmental impacts of the alternatives selected for further analysis is included in the Environmental Analysis being prepared as a separate Phase 1 Angeles Link feasibility study. This desktop analysis was prepared to identify and evaluate potential environmental impacts that could result from construction and operation and maintenance (O&M) of Angeles Link and from the alternatives to Angeles Link. The Environmental Analysis relies on the potential pipeline routes identified in the Preliminary Routing/Configurations Analysis and relies on assumptions related to conventional pipeline construction and O&M for the desktop analysis. Results and impact analysis are based upon publicly available datasets and information.

in Appendix 7.4.3 provides a high-level summary of the assessment completed in the Environmental Analysis.[171]

[171] Refer to the Environmental Analysis for more detailed information.

4.4.2. Cost Effectiveness Findings

Considering the criteria and cost methodology are distinct to each category of alternatives, the findings from the Cost Effectiveness Study are categorized into two sections—Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives.

4.4.2.1. Hydrogen Delivery Alternatives

Findings from the Cost Effectiveness Study were incorporated into this study to compare the cost-effectiveness of the Hydrogen Delivery Alternatives in relation to Angeles Link. Like the Step 2 criteria, cost effectiveness for each alternative was evaluated based on a 4-point scale ranked from high to low using the rubric detailed in Table 11.

Table 11: Cost Effectiveness Assessment Rubric (Hydrogen Delivery Alternatives)

Criteria Selected for Screening	Definition	High	Good	Moderate	Low
Cost Effectiveness	The degree to which the costs[172] associated with the delivery method are competitive relative to alternatives	Below or at $6/kgH_2$	More than $6 and below or at $8/kgH_2$	More than $8 and below or at $10/kgH_2$	More than $10/kgH_2$

Cost-effectiveness assesses the total cost of delivered hydrogen ($/kg), including production, transportation, storage, and delivery to end users. This analysis compares the alternatives using the Levelized Cost of Delivered Hydrogen (LCOH) as the unifying metric. LCOH has the advantage of being an objective and comparable metric across different technologies delivering the same product. The costs are estimated in the Cost Effectiveness Study, where the methodology is explained in detail, along with additional cost-related results.

Cost-effectiveness analysis examines the economic feasibility of each option and follows the 4-point scale ranking defined in Table 9. Table 12 summarizes the results for each delivery mode.

[172] Real 2024 Levelized Cost of Delivered Hydrogen.

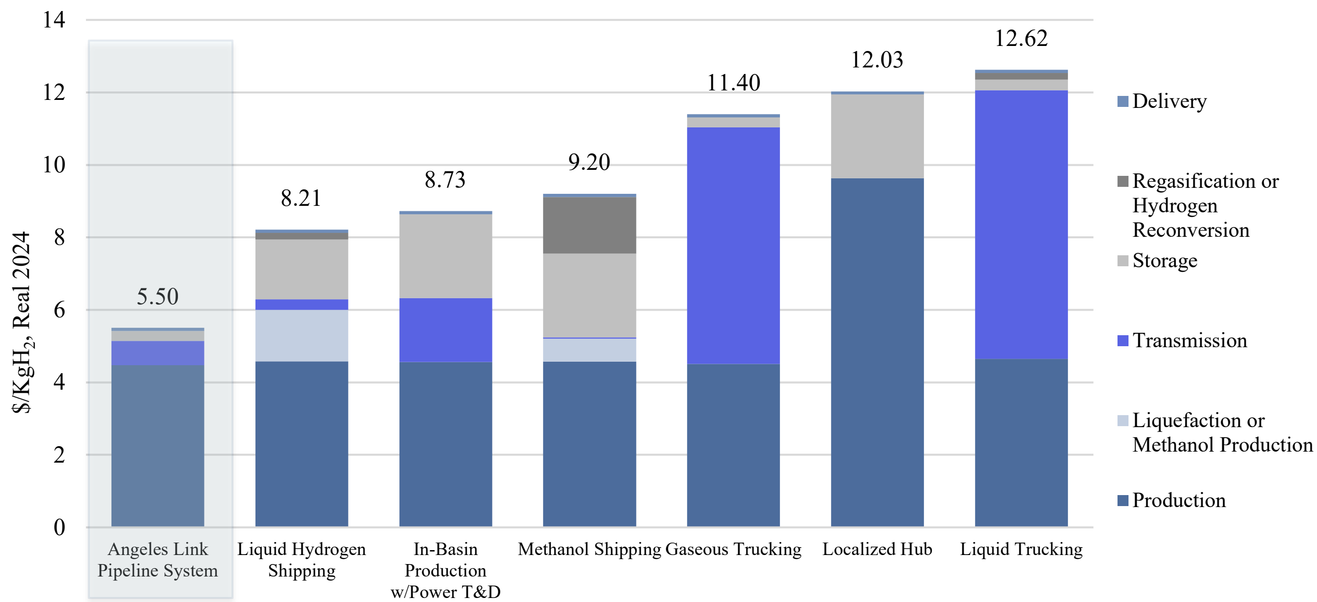
Table 12: Cost Effectiveness

Angeles Link	Gaseous Hydrogen Trucking	Liquid Hydrogen Trucking	Liquid Hydrogen Shipping	Methanol Shipping	In-Basin Production with Power T&D	Localized Hub

High Good Moderate Low

The results shown in Figure 20 correspond to Angeles Link transporting 1.5 Mtpa to connect to third-party production sites such as SJV and Lancaster areas to end users. The component values are included in Appendix 7.2.1.

Figure 20: Cost Effectiveness of Angeles Link vs. Hydrogen Delivery Alternatives[173]



Notes: Reflects costs from Scenario 7 (corresponding to Design Study, Configuration A, single run scenario) for 1.5 Mtpa. Production is assumed to begin in 2030 to take advantage of tax incentives, including Production Tax Credits (PTC) for hydrogen (45V)[174] and power (45Y)[175], which provide \$3 per kgH_2 and \$0.028 per kWh for ten years. Storage assumptions were based on proximity to production sites, and the geographic footprint under consideration for storage in the Production Study. [176] For Angeles Link and the trucking alternatives (gaseous and liquid), identified routes allowed for access to underground storage sites, therefore, underground storage costs were assumed. Delivery alternatives with production sites that did not overlap with the identified geological storage sites, were assumed to rely on above ground storage. These alternatives include shipping, in-basin production with T&D, and localized hub. The shipping solutions include the costs of specialized handling required to deliver methanol and liquid hydrogen. The cost for liquefaction in the liquid hydrogen trucking alternative is included as a part of transmission costs.

Results from the cost effectiveness assessment indicate the following:

1. **Angeles Link Pipeline System** was found to be the most cost-effective method when comparing Angeles Link to the identified Hydrogen Delivery Alternatives for delivering hydrogen at scale across Central and Southern California, at a cost of \$5.50/kgH_2. As with almost every delivery alternative, third-party production cost of the clean renewable hydrogen is the single greatest

[173] See Cost Effectiveness Study 6.3.1 Delivery Alternatives Assumption Tables Delivery Alternatives Assumption Tables and 6.2.2 Delivery Alternatives Descriptions for additional details.
[174] Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property.
[175] Section 45Y Clean Electricity Production Credit and Section 48E Clean Electricity Investment Credit.
[176] For additional details on the rationale for Storage assumptions for each alternative please refer to Cost Effectiveness Study Appendix 7.5.1. The storage solution selected reflects the best available for a like for like comparison.

contributor to total LCOH. The pipeline transmission system represents only 12% of the total LCOH, contributing to its lower costs when compared to other delivery alternatives for the assessed supply locations and volume requirements by 2045.

2. **Liquid hydrogen and methanol shipping alternatives,** though efficient for long-distance transport, are not cost-effective for intrastate needs, with a cost of \$8.21 and \$9.20/kgH_2, respectively. These solutions are expensive overall due to the specialized handling required to convert, reconvert, and store the hydrogen,[177] which incurs higher costs.
3. **In-basin production with power T&D**, while feasible, has a cost of \$8.73/kgH_2, as it would require extensive and costly infrastructure compared to pipelines, as multiple long-distance electric transmission lines are needed to bring the power to production centers and requires in-basin above-ground storage. Costs associated with long distance transmission complemented by above-ground storage can have a significant impact on the cost of delivered hydrogen, especially at scale.[178]
4. **Gaseous and liquid hydrogen trucking** alternatives could serve as interim solutions; however, with a cost of \$11.40 and \$12.62/kgH_2 respectively, they lack the scalability and cost-effectiveness of a pipeline system to support at-scale demand transported over longer distances in a cost-effective manner. Higher transportation costs are driven by the volumetric constraints of trucks, the long distances, and transport time required to connect hydrogen produced via high-quality renewable resources to demand, and additional expenses associated with liquefaction/compression, as well as loading and unloading at production and storage locations.
5. **Localized hub** was found to have the highest production costs, with over \$9.6 /kgH_2. Higher costs are driven by its in-basin location which limits scale and requires the aggregation of electricity from multiple scattered solar generation sites. It is also impacted by the need for above-ground storage costs, as underground storage options have not yet been identified in the localized hub area.

4.4.2.2. Non-Hydrogen Alternatives

Findings from the Cost Effectiveness Study were incorporated into this study to compare the cost-effectiveness of the Non-Hydrogen Alternatives in relation to Angeles Link. Like the Step 2 criteria,

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[177] Storage can occur as methanol as well, but it is assumed to be hydrogen to facilitate comparison between storage on the delivery alternatives. Additionally, it will ultimately be consumed as hydrogen.

[178] More details on storage assumptions can be found at Appendix 7.5.1 in the Cost Effectiveness Study.

cost effectiveness for each alternative was evaluated based on a 4-point scale ranked from high to low using the rubric in Table 13.

Table 13: Cost Effectiveness Assessment Rubric (Non-Hydrogen Alternatives)

Criteria Selected for Screening	Definition	High	Good	Moderate	Low
Cost Effectiveness	Economics relative to Angeles Link based on a common metric	Materially more economic compared to Angeles Link	At or near the cost of Angeles Link	Materially less economic than Angeles Link	Significantly less economic than Angeles Link

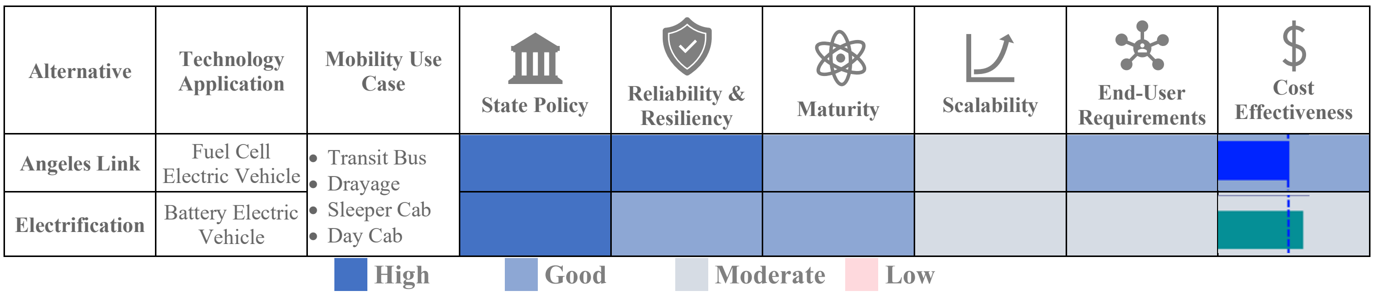
For the cost effectiveness criterion, the results of the Cost Effectiveness Study are summarized in a comparison chart for each use case to illustrate the cost effectiveness of the alternative relative to Angeles Link. See the Cost Effectiveness Study for additional details identifying the use case specific metrics and detailed breakdowns of cost analysis results for Non-Hydrogen Alternatives. This relative cost effectiveness measure was then translated into the 4-point scale for purposes of scoring the cost effectiveness criterion, as discussed in the sub-sections below. Because the use cases and considerations relevant to electrification and CCS differ, each alternative is presented below in direct comparison to end uses consuming hydrogen delivered by Angeles Link across the relevant sectors.

4.4.2.2.1. Electrification Cost Effectiveness Analysis

4.4.2.2.1.1. Mobility

As part of the cost effectiveness analysis for the mobility sector, the Cost Effectiveness Study evaluated FCEVs against BEVs across transit buses, sleeper cabs, day cabs and drayage trucks. Results of the analysis are illustrated in Figure 21, and the main cost are drivers discussed below.

Figure 21: Comparison of FCEVs and BEVs in the Mobility Sector



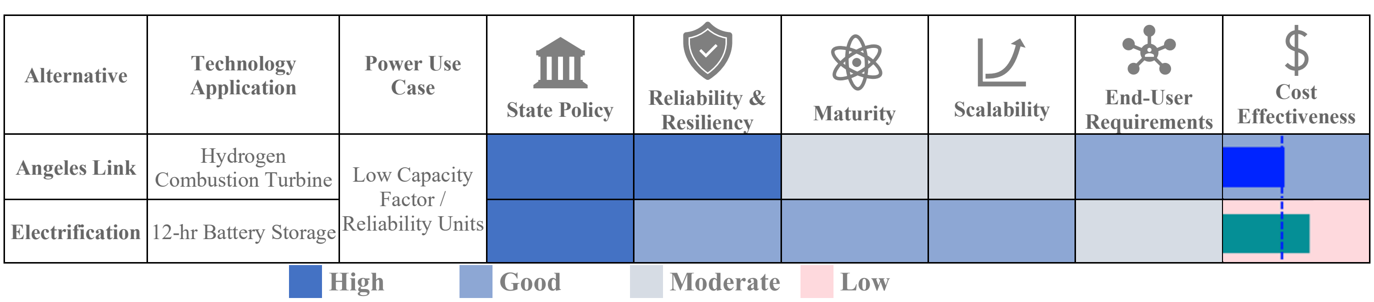
- **Cost Effectiveness. FCEVs are advantaged because of their reduced operational expenses and the comparative disadvantages of BEVs, such as longer charging durations and increased vehicle weight.**

  FCEVs have the potential to be more cost effective than BEVs, particularly in situations where HDVs have a higher payload and more frequent refueling stops. Detailed analysis and discussions of key drivers are provided in the Cost Effectiveness Study.

4.4.2.2.1.2. Power

As part of the cost effectiveness analysis for the power sector, the Cost Effectiveness Study evaluated hydrogen combustion turbines against a 12-hr battery storage unit that has a peaker/reliability dispatch profile. Results of the analysis are illustrated in Figure 22, with the main cost drivers discussed below.

Figure 22: Comparison of Hydrogen Combustion Plants and Battery Storage in the Power Sector



- **Cost Effectiveness. Hydrogen turbines are cost-advantaged due to the high cost of building battery energy storage in configurations sufficient to deliver longer duration capabilities.**

  A gas facility retrofitted with a hydrogen turbine operating as a peaker unit is more cost effective than a lithium-ion battery storage facility built with sufficient redundancy to achieve longer duration capability. The higher hydrogen fuel cost is outweighed by the high capital cost of oversized battery storage. Detailed analysis and discussions of key drivers are provided in the Cost Effectiveness study.

4.4.2.2.1.3. Industrial – Food & Beverage

As part of the cost effectiveness analysis for the F&B sector, the Cost Effectiveness Study evaluated hydrogen ovens and fryers against electric ovens and fryers for low process heating applications. Results of the analysis are illustrated in Figure 23, with the main cost drivers discussed below.

Figure 23: Comparison of Hydrogen and Electric Kilns in the Food & Beverage Sector

Alternative	Technology Application	Food and Beverage Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements	Cost Effectiveness
Angeles Link	Hydrogen Ovens/Fryers	Low Process Heating Application						
Electrification	Electric Ovens/Fryers							

High Good Moderate Low

- **Cost Effectiveness. Hydrogen kilns are advantaged due to the relatively high electricity rates in California.**
  While electrification of low to medium process heating applications is technically feasible, hydrogen ovens and fryers are more cost effective (on a fuel cost basis only) due to relatively high industrial electricity tariffs in California. For example, the weighted average retail rate for industrial customers in Pacific Gas & Electric's (PG&E) service territory is 21 cents per kWh or about $62 per MMBtu, which is about 53% higher than the delivered cost of hydrogen on a $/MMBtu basis.[179] Additional details are provided in the Cost Effectiveness Study.

4.4.2.2.1.4. Industrial – Cement

As part of the cost effectiveness analysis for the cement sector, the Cost Effectiveness Study evaluated hydrogen and electric cement kilns for high process heating applications. Results of the analysis are illustrated in Figure 24, with the main cost drivers discussed below.

[179] PG&E Industrial Tariffs – Industrial Service (B-20)

Figure 24: Comparison of Angeles Link and Electrification in the Cement Sector

Alternative	Technology Application	Cement Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements	Cost Effectiveness
Angeles Link	Hydrogen Kiln	High Process Heating Application						
Electrification	Electric Kiln							

High Good Moderate Low

- **Cost Effectiveness. Hydrogen kilns are advantaged due to high electricity rates in California.**

  While electrification of high process heating applications is becoming more technically feasible, Angeles Link is more cost effective (on a fuel cost basis only) due to relatively high industrial electricity tariffs in California. For example, the weighted average retail rate for industrial customers in PG&E service territory is 21 cents per kWh or about $62 per MMBtu, which is about 53% higher than the delivered cost of hydrogen on a $/MMBtu basis. Additional details are provided in the Cost Effectiveness study.

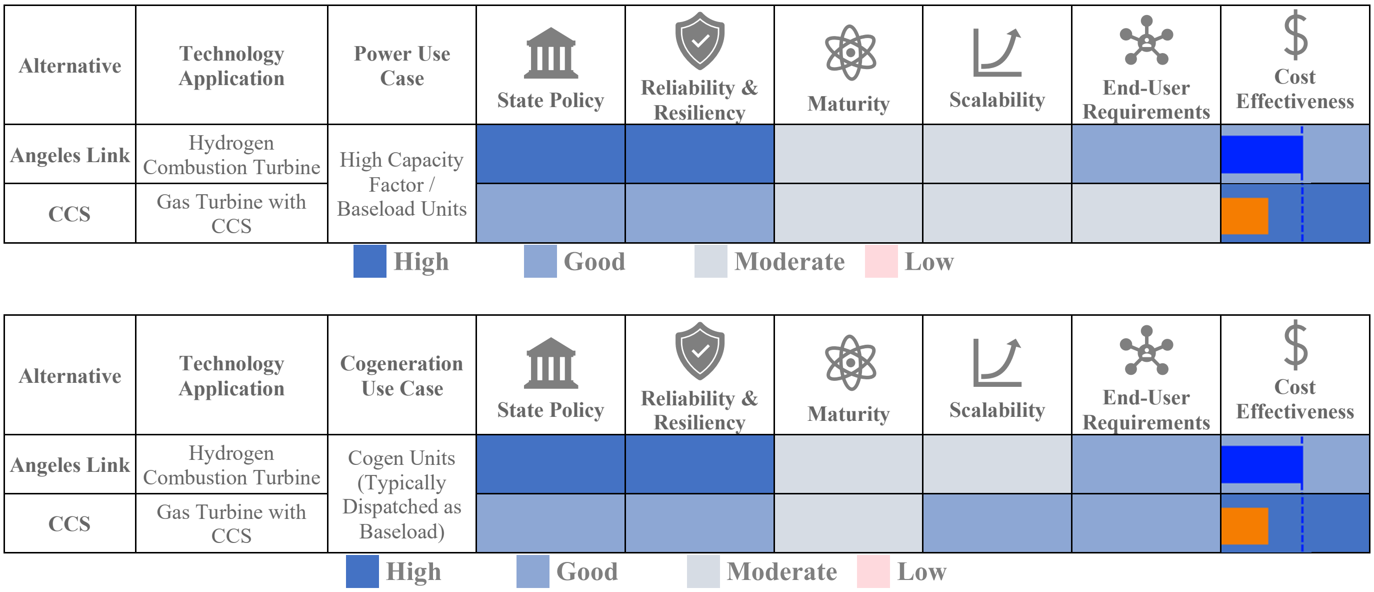
4.4.2.2.2. CCS Cost Effectiveness Analysis

4.4.2.2.2.1. Power and Cogeneration

Across the power and cogeneration use cases, the cost effectiveness analysis evaluated hydrogen turbines and natural gas turbines retrofitted with CCS equipment for a baseload dispatch profile. Results of the analysis are illustrated in Figure 25, with the main cost drivers discussed below.[180]

[180] The CCS cost analysis reflects several important assumptions, including sufficient space for capture equipment within the plant boundary, access to transport and sequestration infrastructure, transport and sequestration tariffs based on a commercially reasonable level of utilization, and no new carbon taxes. Refer to the Cost Effectiveness Study for additional details of assumptions, key drivers, and results of cost analysis. See Appendix 7.3.2 for additional CCS considerations.

Figure 25: Comparison of Hydrogen Turbines and Gas Turbines with CCS in the Power and Cogeneration Sectors



- **Cost Effectiveness. Hydrogen turbines are not at cost parity due to the lower cost of natural gas relative to hydrogen.**

  Under the assumptions considered for the purpose of this study, gas facilities retrofitted with carbon capture equipment are currently a more cost effective decarbonization solution than gas facilities retrofitted with a hydrogen turbine. The higher hydrogen fuel cost outweighs the higher capital expenditure of the carbon capture equipment, although the gap can narrow significantly depending on the CO_2 transport and sequestration cost, which is dictated by the integration of distributed point source CO_2 emitters for the development of large-scale CO_2 transport pipeline infrastructure. The integration of CO_2 point source emitters would increase if various sectors within California's economy were to implement CCS technology concurrently, which could drive costs down. In contrast, the emissions output from single industrial point sources might not be adequate to warrant the economic outlay for a CO_2 pipeline. The gap in cost parity between hydrogen turbines and gas turbines with CCS may decline over time as the cost of delivered hydrogen is expected to decline. For an in-depth analysis and exploration of the cost factors, refer to the Cost Effectiveness Study.

4.4.2.2.2.2. Industrial – Cement

As part of the cost effectiveness analysis for the cement sector, the Cost Effectiveness Study evaluated hydrogen kilns and kilns retrofitted with CCS for high process heating applications. Results of the analysis are illustrated in Figure 26, with the main cost drivers discussed below.

Figure 26: Comparison of Hydrogen Kilns and Gas Kilns with CCS in the Cement Sector

Alternative	Technology Application	Cement Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements	Cost Effectiveness
Angeles Link	Hydrogen Kiln	High Process Heating Application						
CCS	Gas Kiln with CCS							

High Good Moderate Low

- **Cost Effectiveness. Hydrogen kilns are currently not at cost parity due to the lower cost of natural gas relative to hydrogen.**
  Cost effectiveness in the cement sector was analyzed based on fuel cost and the cost of CO_2 transport and sequestration. For the cement sector analysis, the capital costs associated with hydrogen kiln retrofits and CO_2 capture equipment were not considered, nor were the costs of incremental energy to power the capture equipment. Hydrogen's current higher fuel cost vs. natural gas generally outweighs the anticipated cost of CO_2 transport and sequestration, making CCS the more cost-effective solution.[181] However, this gap could significantly narrow depending on the CO_2 transport and sequestration cost, which is dictated by the integration of distributed point source CO_2 emitters to the broader CO_2 transport infrastructure. The gap in cost parity between hydrogen kilns and gas kilns with CCS may decline over time as the cost of delivered hydrogen is expected to decline. For an in-depth analysis and exploration of the cost factors, refer to the Cost Effectiveness Study.

[181] The CCS cost analysis reflects several important assumptions, including sufficient space for capture equipment within the plant boundary, access to transport and sequestration infrastructure, transport and sequestration tariffs based on a commercially reasonable level of utilization, and no new carbon taxes. Refer to the Cost Effectiveness Study for additional details of assumptions, key drivers, and results of cost analysis. See Appendix 7.3.2 for additional CCS considerations.

4.4.2.2.2.3. Industrial – Refineries

In the refinery use case, the cost effectiveness analysis evaluated clean renewable hydrogen provided by Angeles Link and low-carbon hydrogen provided by existing unabated hydrogen supply with CCS for refinery process needs. Results of the analysis are illustrated in Figure 27, with the main cost drivers discussed below.

Figure 27: Comparison of Clean Renewable Hydrogen and Low-Carbon Hydrogen in the Refinery Sector

Alternative	Technology Application	Refinery Use Case	State Policy	Reliability & Resiliency	Maturity	Scalability	End-User Requirements	Cost Effectiveness
Angeles Link	Clean Renewable Hydrogen	Fuel Switching						
CCS	Low-Carbon Hydrogen							

High Good Moderate Low

- **Cost Effectiveness. Clean renewable hydrogen is currently not at cost parity due to the relatively lower cost of natural gas for unabated hydrogen with CCS.**
  Cost effectiveness in the refinery sector was analysed based on LCOH for hydrogen delivered via Angeles Link vs. near-site hydrogen retrofitted with CCS from SMRs, including the anticipated cost of CO_2 transport and sequestration. Near site hydrogen using CCS is currently expected to be more cost effective for refineries than clean renewable hydrogen.[182] However, this gap could narrow depending on the CO_2 transport and sequestration, which is dictated by the integration of distributed CO_2 point source emitters to the broader CO_2 transport infrastructure. The gap in cost parity between clean renewable hydrogen and abated hydrogen with CCS may decline over time as the cost of clean renewable hydrogen is expected to decline. For an in-depth analysis and exploration of the cost factors, refer to the Cost Effectiveness Study.

[182] The CCS cost analysis reflects several important assumptions, including sufficient space for capture equipment within the facility boundary, access to transport and sequestration infrastructure, transport and sequestration tariffs based on a commercially reasonable level of utilization, and no new carbon taxes. Refer to the Cost Effectiveness Study for additional details of assumptions, key drivers, and results of cost analysis. See Appendix 7.3.2 for additional CCS considerations.

4.4.3. Purpose and Need Assessment

As a final step in the evaluation of Angeles Link relative to Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives, this study performed a summary assessment based on the purpose and need for Angeles Link. This final step examines the criteria and analyses conducted in this study to allow for a comprehensive consideration of Angeles Link's purpose and need.

The nine elements of purpose and need are presented below.

1. **California-wide decarbonization.** To support the State of California's decarbonization goals, including the California Air Resources Board's (CARB) 2022 Scoping Plan for Achieving Net Neutrality, which identifies the scaling up of hydrogen for the hard-to-electrify sectors as playing a key role in the State achieving carbon neutrality by 2045 or earlier.[183]
2. **Mobility decarbonization.** To support the State of California's decarbonization goals in the mobility sector, including the Governor's Executive Order N-79-20, which seeks to accelerate the deployment of zero-emission vehicles;[184] CARB's implementation of the Advanced Clean Fleets regulation, which is a strategy to deploy medium- and heavy-duty zero-emission vehicles;[185] as well as the implementation of the March 15, 2021 Advanced Clean Truck regulation, which aims to accelerate a large-scale transition of zero-emission medium- and heavy-duty vehicles.[186]
3. **Open access.** To optimize service to all potential end-users in the project area by operating an open access, common carrier clean renewable hydrogen transportation system dedicated to public use.
4. **Air quality.** To support improving California's air quality by displacing fossil fuels for certain hard-to-electrify uses, including the mobility sector.
5. **Reliability.** To enhance energy system reliability, resiliency, and flexibility as California industries transition fuel usage to achieve the State's decarbonization goals.

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[183] California Air Resources Board's 2022 Scoping Plan for Achieving Carbon Neutrality, at pp. 9-10.
[184] Governor's Executive Order N-79-20, also CARB's Advanced Clean Fleets and Truck regulations.
[185] Advanced Clean Fleets Regulation – CARB.
[186] Advanced Clean Trucks – CARB.

6. **Long-duration storage.** To enable long-duration clean energy storage that can further accelerate renewable development, minimize renewable curtailments, and provide seasonal storage when renewable output is diminished.
7. **Cost.** To provide a cost effective and affordable open access clean renewable hydrogen transportation system at just and reasonable rates.
8. **Safety.** To provide efficient and safe clean renewable energy transportation in support of the State's decarbonization goals.[187]
9. **Reduce reliance on Aliso Canyon.** Over time and combined with other current and future clean energy projects and reliability efforts, to help support decreased reliance on Aliso Canyon natural gas storage facility, while continuing to provide reliable and affordable energy service to the region.

Each alternative's level of alignment with the applicable purpose and need elements was evaluated based on the findings of this study and other considerations where direct evidence from this study was not available. Table 14 summarizes the purpose and need evaluation, with additional context for the scoring provided below.

[187] California Air Resources Board's 2022 Scoping Plan for Achieving Carbon Neutrality, at pp. 9-10.

Table 14: High-Level Assessment of Alternatives' Alignment with Purpose & Need for Angeles Link

	Angeles Link	Trucking	Shipping	In-Basin Production with Power T&D	Localized Hub	Electrification	CCS
California-wide decarbonization					Sub-scale	Cannot serve all sectors	Cannot serve all sectors
Mobility decarbonization					Sub-scale		Cannot serve mobility[188]
Open access		N/A	N/A	If distribution is open access			If CO_2 pipeline is open access
Air quality							
Reliability		Lower dispatchability	Lower dispatchability		Sub-scale	Need clean firm	Secondary system alongside gas
Long-duration storage						LDES still emerging	Existing gas storage
Cost		Higher LCOH	Higher LCOH	Higher LCOH	Higher LCOH	High electricity tariffs	
Safety							
Reduce reliance on Aliso Canyon					Sub-scale		No reduction in gas

High alignment | Some alignment | Low or no alignment | Not applicable (N/A)

Trucking inherently has lower dispatchability than a pipeline system and is therefore less reliable. Trucking has low alignment with the air quality objective, given tailpipe emissions from trucks in the short to near term horizon. It requires extensive loading/offloading infrastructure, where safety incidents are more likely to occur[189]. Trucking also comes at a higher cost than a pipeline system based on the results of the Cost Effectiveness Study.

Shipping inherently has lower dispatchability than a pipeline system and is therefore less reliable. Shipping has low alignment with the air quality objective, given emissions from ocean vessels in the

[188] While direct air capture (DAC) is a form of carbon dioxide capture that could help address mobility emissions, this study was focused on point source carbon dioxide capture and its implications for end use emitters.
[189] Fraser Institute, Fraser Research Bulletin: Safety in the Transportation of Oil and Gas: Pipelines or Rail? (August 2015), at p. 3.

short to near term horizon and supporting facilities. While shipping is generally considered a safe method of transporting oil and gas, shipping alternatives would require extensive loading/offloading infrastructure, where safety incidents are more likely to occur. [190] While the shipping alternative has been assumed to be able to access storage sized to meet long-duration requirements, this storage is assumed to be solely above-ground, which comes with cost and feasibility challenges at the scale required.[191] Shipping also comes at a higher cost than a pipeline system based on the results of the Cost Effectiveness Study.

In-basin production with power T&D can be used as an open access solution dedicated to public use for the hydrogen produced and transported in-basin. This alternative has high alignment with the air quality objective because it can deliver the same volume of hydrogen for end users without increasing emissions from the mode of delivery. In-basin production with power T&D has potentially greater safety considerations than Angeles Link, as production would be in more urbanized areas compared to Angeles Link. While this alternative has been assumed to access hydrogen storage sized to meet long-duration requirements, storage is assumed to be solely above-ground, which comes with cost and feasibility challenges at the scale required.[192] This alternative also comes at a higher cost than a pipeline system based on the results of the Cost Effectiveness Study.

Localized hub, due to its inherent limitation to scale to meet the expected hydrogen demand by end users in Central and Southern California, offers a partial solution to meet a fraction of the in-basin decarbonization needs, including the mobility sector. This alternative has low alignment with the air quality objective due to its limited scalability. Localized hub has potentially greater safety considerations than Angeles Link, as hydrogen production would occur in more urbanized areas compared to Angeles Link. This sub-scale nature also impacts the localized hub's ability to meet the system's reliability and resiliency needs and support the scale of reduction in natural gas usage.

Electrification will be one of the most important decarbonization pathways, in addition to hydrogen and CCS, and can provide both decarbonization and air quality benefits. However, it offers limited potential across hard-to-electrify sectors. This non-hydrogen alternative could also result in safety concerns if the

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[190] Fraser Institute, Fraser Research Bulletin: [Safety in the Transportation of Oil and Gas: Pipelines or Rail?]() (August 2015), at p. 3.
[191] More details on storage assumptions can be found in the Cost Effectiveness Study Appendix 7.5.1.
[192] Ibid.

energy system is less reliable and resilient (e.g., safety issues during extended outages). As discussed in the system electrification appendix, it is challenging for renewables and battery storage alone to provide the clean firm generation essential to support energy system reliability. Finally, high electricity tariffs in California impact the cost effectiveness of electrification across multiple sectors.[193]

CCS offers a potential pathway to support decarbonization of the cement industry in California (SB 596).[194] CCS has some alignment with the air quality objective given the potential for concurrent air emission reductions along with greenhouse gas emission reductions. CCS could introduce infrastructure development and operational challenges associated with the integration of both gas and CO_2 transportation and storage networks. The adoption of CCS solutions will most likely be driven by region-specific considerations (such as proximity of multiple point sources at scale and accessibility of sequestration sites) as well as federal, state, and local decarbonization policies.

[193] PG&E Industrial Tariffs – Industrial Service (B-20).
[194] Net-Zero Emissions Strategy for the Cement Sector | California Air Resources Board.

5. Key Findings

This section summarizes the overall findings of the study across all criteria analyzed for Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives.

5.1. Hydrogen Delivery Alternatives

The evaluation of Angeles Link and Hydrogen Delivery Alternatives found that Angeles Link is the best suited option to meet the evaluation criteria for the delivery of clean renewable hydrogen at scale across Central and Southern California, including the L.A. Basin. A key advantage of Angeles Link is that it supports the delivery of clean hydrogen at the scale required to serve the heavy-duty transportation, clean dispatchable power generation, and hard-to-electrify industrial sectors in support of California's decarbonization objectives. Table 15 compares alternatives based on the 4-point scale developed across all identified criteria.

Table 15: Hydrogen Delivery Alternatives Comparison

Project and Alternatives	State Policy	Range	Reliability & Resiliency	Ease of Imp.	Scalability	Cost Eff. ($/KgH$_2$)	Key Findings
Angeles Link Pipeline System	High	High	High	Moderate	High	High	Appropriate for distance/scale. Potential to continually access storage, increasing delivered hydrogen reliability/resiliency
Liquid Hydrogen Shipping	Moderate	Good	Moderate	Moderate	Moderate	Good	Efficient long-distance transportation of H_2 requires specialized handling and above-ground storage facilities
In-Basin Production w/ Power T&D	High	Good	Good	Moderate	Low	Good	In-basin hydrogen production incurs additional electric T&D costs, and is also limited by hard to resolve transmission constraints. Scalability limited by above-ground storage need
Methanol Shipping	Moderate	High	Moderate	Moderate	Moderate	Good	Requires additional processing steps, specialized handling and storage facilities. Suitable for relatively long-distances
Gaseous Trucking	Good	Moderate	Moderate	High	Low	Moderate	Quickly deployable. Scalability of on-road transportation is limited
Liquid Trucking	Good	Moderate	Good	Good	Moderate	Moderate	Quickly deployable. Scalability of on-road transportation is limited. Higher costs due to storage and loading costs
Localized Hub	High	Low	Good	Moderate	Low	Moderate	Production costs alone for the localized hub exceed the cost of other alternatives; this option cannot be scaled to meet projected demand
Ammonia Shipping	Moderate	High	Moderate	Low	Low	Screened Out	
Intermodal Transport (Liq. Truck+ Train)	Low	Good	Low	Moderate	Low		

High Good Moderate Low

The **Angeles Link Pipeline System** provides the best scalability to serve the 1.5 Mtpa of clean renewable hydrogen throughput as defined in the Demand Study. It is also the most reliable and resilient alternative due to its potential to integrate storage access via multiple routes.[195] The Cost Effectiveness Study also found Angeles Link to be the most cost-effective hydrogen delivery solution for the distance/scale evaluated. Other delivery alternatives like trucking, shipping, and in-basin production with power T&D are less scalable, reliable, resilient, and cost effective than Angeles Link. These alternatives face a higher risk of supply disruption, suboptimal economics, and higher-cost storage access.

The shipping solutions are efficient for the long-distance transportation of hydrogen. These delivery alternatives may also become relevant for potential hydrogen exports as an option to manage costs for local end users by sharing the infrastructure costs as domestic demand ramps up. However, shipping is not the most suitable option for transporting intrastate hydrogen production throughout Central and Southern California, as envisioned for Angeles Link.

In-basin production with power T&D is also an efficient long-distance land transportation alternative. However, for the volumes analyzed, the system would need multiple parallel transmission lines, which would impact its delivery costs and impact the feasibility of implementation. As a result, this delivery alternative ranks comparatively below a pipeline like Angeles Link to meet the 1.5 Mtpa demand as defined in Scenario 7.[196]

Gaseous and liquid hydrogen trucking solutions provide the most favorable ease of implementation but lack the cost and scalability of a pipeline solution for the volumes and distances envisioned. However, trucking solutions may be a bridge option to Angeles Link for hydrogen distribution as demand reaches critical mass for transmission and distribution pipelines.

Finally, the feasibility of a **localized hub** option is constrained by scale-driven capacity limitations to build dedicated renewable electricity resources within L.A. Basin. As a result of land availability constraints in the L.A. Basin area, a localized hub can only provide 9.3% of the 1.5 Mtpa hydrogen

[195] More details on storage assumptions can be found in the Cost Effectiveness Study Appendix 7.5.1.
[196] More details on the new transmission infrastructure requirements and costs can be found in the Cost Effectiveness Study Appendix 7.3.1.2.4.

throughput expected in 2045. This alternative also faces significantly higher development costs, which results in a higher LCOH in-basin.[197]

The **ammonia shipping** and **intermodal** (liquid hydrogen trucking and liquid rail) options were excluded from further analysis because these options were incompatible with the evaluation criteria.

5.2. Non-Hydrogen Alternatives

This study's findings indicate that clean renewable hydrogen delivered via Angeles Link is well suited to serve hard-to-electrify industries, including electric generation, heavy-duty transportation, and certain industrial sectors. These findings are aligned with the Demand Study, which projected meaningful hydrogen adoption rates in these and other sectors, indicating total hydrogen demand in the region of 1.9 to 5.9 million tons per year by 2045, 0.5-1.5 Mtpa of which is proposed to be served by Angeles Link.

Table 16 below summarizes the use case-level scores and key findings for Angeles Link, electrification, and CCS based on the 4-point scale across all of the identified criteria and use cases. Taken together, these scores provide an indication of the strengths and weaknesses of each alternative and their ability to serve the use cases targeted by Angeles Link. Following the table, cross-sector findings are discussed for electrification and CCS as overall decarbonization pathways relative to Angeles Link.

[197] As seen in the Cost Effectiveness Study.

Table 16: Non-Hydrogen Alternatives Comparison

Use Case[198]	Project & Altern-atives	State Policy	Reliability & Resiliency	Maturity	Scalabil-ity	End-User Req.	Cost Eff.	Key Findings
Mobility *1.0 Mtpa*	AL	High	High	Good	Moderate	Good	Good	FCEVs utilizing hydrogen are better suited to serve the operational requirements of long-haul, high payload, high duty-cycle vehicles than BEVs.
	Elec.	High	Good	Good	Moderate	Moderate	Moderate	
Power *1.7 Mtpa*	AL	High	High	Moderate	Moderate	Good	Good	While battery storage is mature and modular, it is cost-prohibitive to build at the scale required for long-duration system reliability needs without advances in other LDES technologies.
	Elec.	High	Good	Good	Good	Moderate	Low	
	AL	High	High	Moderate	Moderate	Good	Good	Hydrogen and CCS are well-positioned in the power sector. Adoption may be determined on an asset specific level depending on proximity to potential transportation and storage infrastructure.
	CCS	Good	Good	Moderate	Moderate	Moderate	High	
Cogeneration *0.4 Mtpa*	AL	High	High	Moderate	Moderate	Good	Good	Cogeneration units are well suited for both hydrogen and CCS. Adoption may be determined on an asset specific level depending on proximity to potential transportation and storage infrastructure. Those units that are co-located with refineries may be best suited for CCS; others may be better suited for hydrogen due to cost of supporting infrastructure.
	CCS	Good	Good	Moderate	Good	Good	High	
Food & Beverage *0.03 Mtpa*	AL	Good	High	Moderate	Moderate	Moderate	Good	Both Angeles Link and electrification are good solutions for certain applications. Specifically, electrification is a more mature, scalable solution for low-to-medium heat applications. Generally, hydrogen delivered via Angeles Link may be more cost-effective based on current industrial electricity tariffs.
	Elec.	High	Good	High	Good	Moderate	Low	
Cement *0.02 Mtpa*	AL	High	High	Moderate	Moderate	Moderate	Good	CCS has the potential to be more cost-effective; however, this assumes access to CO_2 transport and sequestration infrastructure. CCUS also has the potential to address cement emissions beyond the kiln, supporting SB596 targets.
	CCS	High	Good	Moderate	Good	Good	High	
	Elec.	High	Good	Moderate	Moderate	Moderate	Low	
Refineries *0.7 Mtpa*	AL	Good	High	Moderate	Moderate	Moderate	Good	CCS may be a decarbonization tool for refineries due to current cost differences between clean renewable hydrogen and unabated hydrogen and existing contracts with unabated hydrogen suppliers. However, Angeles Link has the potential to play a role where site constraints or lack of existing near site unabated hydrogen supply or CO_2 transport or storage infrastructure create opportunity
	CCS	Good	Good	Moderate	Good	Good	High	

High Good Moderate Low

Angeles Link can play a key role supporting California's decarbonization objectives as identified in the CARB's 2022 Scoping Plan. Angeles Link is intended to support the CARB's Scoping Plan and California's decarbonization goals through the delivery of clean renewable hydrogen to serve customers in hard-to-electrify sectors. Angeles Link performed well with respect to the criteria defined for the evaluation of Non-Hydrogen Alternatives and is well positioned to serve hard-to-electrify industrial consumers, dispatchable electric generation, and heavy-duty transportation in Central and Southern California.

Electrification is and will continue to be a major driver of the energy transition in California; however, a 100% clean, reliable energy system is not likely to be solely served by renewables and battery storage and meet all expected energy demand.[199,200] CARB and several other industry sources model the need for clean firm dispatchable power resources in addition to a renewables and battery portfolio in order to support system reliability and meet the State's policy targets.[201] In the mobility sector, Angeles Link is well-suited to serve the operational requirements of heavy-duty, long-range trucks and buses. In the power sector, renewables and battery energy storage can be paired with clean firm generation and LDES, which is facilitated by Angeles Link. Finally, in several industrial subsectors, high electricity tariffs in California make the cost of hydrogen supplied by Angeles Link competitive with electrification, especially for higher heat applications like cement. While this analysis was required by the CPUC to compare electrification as an "alternative" to Angeles Link, the CARB Scoping Plan supports the finding that a portfolio of pathways, including electrification and clean renewable hydrogen, will be needed to drive the State's decarbonization goals.

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[198] Circles reflect 2045 projected hydrogen demand (in Mtpa) in the Demand Study "Moderate Case", with the exception of refineries, for which demand was only projected in the "Ambitious Case". See Demand Study for additional information.
[199] The CEC's 2023 Integrated Energy Policy Report (IEPR) also identifies clean renewable hydrogen's potential to support electric generation, transportation electrification, and industrial decarbonization. (CEC, 2023 Integrated Energy Policy Report, Chapter 2: Potential Growth of Clean and Renewable Hydrogen, available at: 2023 Integrated Energy Policy Report. The IEPR reports: "California is electrifying much of the transportation and building sectors while rapidly scaling up deployment of low-carbon, renewable generation like solar and wind that are increasingly paired with lithium-ion battery storage. Yet these resources alone may not be sufficient to reach economy-wide decarbonization."
[200] Governor Gavin Newsom, Building the Electricity Grid of the Future: California's Clean Energy Transition (May 2023), available at: Building the Electricity Grid of the Future: California's Clean Energy Transition Plan ("[C]lean sources of electricity like solar and wind energy are more variable and more intermittent. We will not be able to build a reliable, clean electric grid using solar and wind energy alone. California needs more diverse clean energy resources – including batteries, clean hydrogen, and long duration storage - and a wide range of technologies and resources to meet the unprecedented growth in demand for electricity at all hours of the day and different times of year.").
[201] Described in greater detail in Appendix 7.3.3.

CCS provides a potential pathway to achieve the State's carbon neutrality targets by 2045, particularly for certain industrial sectors like refineries and cement. Refinery hydrogen is one of the most viable use cases for CCS solutions due to the ability for CCS to be integrated with existing hydrogen supply agreements. Additionally, the scale and location of refinery hydrogen emissions could support the integration of smaller nearby CO_2 point sources with CO_2 transport and sequestration infrastructure. Cement is also a viable use case for CCS due to the ability of CCS solutions to support SB 596 targets. However, CCS may face challenges in terms of maturity and scalability in power and other industrial sectors. The adoption of CCS for capturing CO_2 is highly sector and location specific, and will require the consideration of site, sector, and regional factors, that may require further evaluation beyond the scope of this study. For example, access to CO_2 transport and sequestration infrastructure near point sources is crucial to the development of capture projects, particularly for point sources that do not have the scale to support integrated infrastructure development on their own. Additional considerations include site-level decarbonization strategies, geospatial constraints, or remaining facility life. Regional dynamics such as natural gas prices, or new federal or state level carbon reduction mechanisms may also impact the commercial viability of CCS implementation.

6. Stakeholder Comments

The Alternatives Study received feedback from various stakeholders engaged in the Angeles Link PAG and CBOSG processes, including feedback on the study's Preliminary Findings and draft report preview during the June 2024 PAG and CBOSG meetings. All comments, as captured in the SoCalGas Angeles Link Quarterly Report to the CPUC, reflect diverse perspectives from organizations such as the Environmental Defense Fund (EDF), Air Products, Communities for a Better Environment (CBE), among others. Written stakeholder comments are compiled and responded to in SoCalGas's quarterly reports, which are accessible on SoCalGas's website.[202]

Key themes in the feedback included:

- Electrification is a clean, safe, and affordable way to meet California and Los Angeles's climate goals. Include localized hub, electrification of end uses, trucking and marine shipping, and behind-the-meter green hydrogen production and use electrolyzers powered by on-site renewables or grid-delivered renewable electricity as alternatives in the Alternatives Study.
- SoCalGas should compare private sector investment options to ratepayer-funded hydrogen projects.
- The criteria for selecting and assessing alternatives are not clearly defined.

With respect to stakeholders' comments on electrification and the localized hub, electrification and a localized hub are included as alternatives in the Alternatives Study and have been evaluated in the Cost Effectiveness Study and the Environmental Analysis.

With respect to comparing private sector investment options to ratepayer funded hydrogen projects, the D.22-12-055 requires SoCalGas to evaluate costs, environmental impacts, and cost-effectiveness of Angeles Link as compared to potential alternatives. Angeles Link is proposed as a non-discriminatory pipeline system to be developed by a private sector company (SoCalGas). To date, SoCalGas is not aware of any proposed unregulated infrastructure investment that would serve the same function as Angeles Link, which is specifically proposed to transport clean renewable hydrogen into the Los Angeles Basin and in the broader Central and Southern California region and serve multiple end users through an open-access pipeline system. Issues concerning ratepayer funding are outside the scope of

[202] Angeles Link | SoCalGas.

this study, which focuses on a comparison of hydrogen pipeline transport as envisioned for Angeles Link against other hydrogen delivery and non-hydrogen alternatives. As such, the information and analysis in this report is relevant for hydrogen pipelines and alternatives generally.

With respect to stakeholders' comments on the criteria for selecting and assessing alternatives, the Alternatives Study has expanded the discussion around the selection and assessment criteria in this report in Section 4 (Framework for Evaluation of Project Alternatives).

7. Appendix

7.1. Alternatives Descriptions

7.1.1. Localized Hub Definition[203]

A dedicated clean renewable hydrogen pipeline system located within the L.A. Basin with production and end use in close proximity that could support connections between the state's decarbonization projects within the ARCHES portfolio. This Localized Hub connects clean renewable hydrogen producers to multiple end users in the hard-to-electrify sectors via open access, common carrier pipeline infrastructure. The Localized Hub within the L.A. Basin is fed only by in-basin renewable generation and hydrogen production and/or production in close proximity to multiple in-basin end users and storage. The considerations for the Localized Hub are split into two areas: A) Geography and B) Value Chain Evaluation.

A. **Geography** The L.A. Basin is a geographically defined area in Southern California; a coastal plain bounded by the Pacific Ocean to the west and surrounded by mountains and hills, including the Santa Monica Mountains to the north, the San Gabriel mountains to the northeast, and the Santa Ana Mountains to the southeast. The L.A. Basin encompasses the central part of Los Angeles County, including portions of the San Fernando Valley, and extends into parts of Orange, Riverside and San Bernardino counties.
B. **Value Chain Evaluation** The Localized Hub is characterized and analyzed to account for the hydrogen value chain to support local production, transport, storage, and delivery systems and the associate feasibility considerations.
    a. **Production**: The Localized Hub considers hydrogen production within and in close proximity to multiple in-basin end users and storage and will assess production prospects within a 40-mile radius expanding outward from the area of concentrated demand near the Ports of Los Angeles and Long Beach. This approach is designed to encompass the L.A. Basin and those outskirt areas close to multiple in-basin end users and storage. See Figure 28 for a map depicting the L.A. Basin and close proximity boundary.

[203] D.22-12-055, p. 75 ("SoCalGas shall study a localized hydrogen hub solution, under the specifications required to be eligible for federal funding provided through the Infrastructure Investment and Jobs Act, as part of Phase One.").

Hydrogen production will include two primary feedstocks: solar energy and biomass. Regarding solar energy, the assessment will include the feasibility of constructing independent solar power sites. Biomass will focus on the utilization of woody biomass and the conversion of municipal waste.

b. **Target Demand Sectors**: The Hub aims to address the dedicated demand from multiple sectors within the L.A. Basin contributing to a reduction in GHG emissions and will seek to meet the diverse capacity and unique consumption patterns of the different end use applications. These sectors include the following:

   i. Power Generation: Supporting the transition to cleaner energy solutions for public and private power generation facilities.

   ii. Industrial & Commercial Manufacturing: Catering to the energy and feedstock demands of factories, processing plants, and other industrial and manufacturing end users.

   iii. Mobility: Especially focusing on heavy-duty trucking operations emerging from ports, which require substantial low-carbon and zero-carbon energy solutions. The Localized Hub's close proximity to ports provides efficient fueling solutions for these heavy-duty transport systems.

c. **Pipeline Transmission**: Within the Hub, hydrogen would be transported through a series of high-pressure trunk transmission pipelines to connect production and offtake and facilitate potential connections to third-party storage facilities. The pipeline system would be designed for safe, efficient, and rapid transport of hydrogen from production sources located within or close to multiple delivery points within the L.A. Basin. For purposes of the feasibility stage, the Hub is assumed to include approximately 80 miles of transmission pipeline within the 40-mile radius for production and storage assessed for the Hub. This mileage corresponds to the miles of transmission pipeline that would be located within the L.A. Basin for the Angeles Link preferred routes, as this provides a baseline for potential transmission needs for the Hub to connect well-known demand centers near the Ports of Los Angeles and Long Beach. The total mileage of pipelines for the Hub may be greater, as land constraints may result in more distributed production facilities and additional pipeline mileage needed for transmission and distribution to meet the production, demand, and storage needs.

d. **Storage**: In the intermittence of synchronized production and demand, reserve hydrogen would be stored above-ground. Storage solutions within a 40-mile radius expanding from the area of concentrated demand near the Ports of Los Angeles and Long Beach are considered with regard to their high-level suitability and technology readiness level.

Figure 28: Localized Hub Area Map

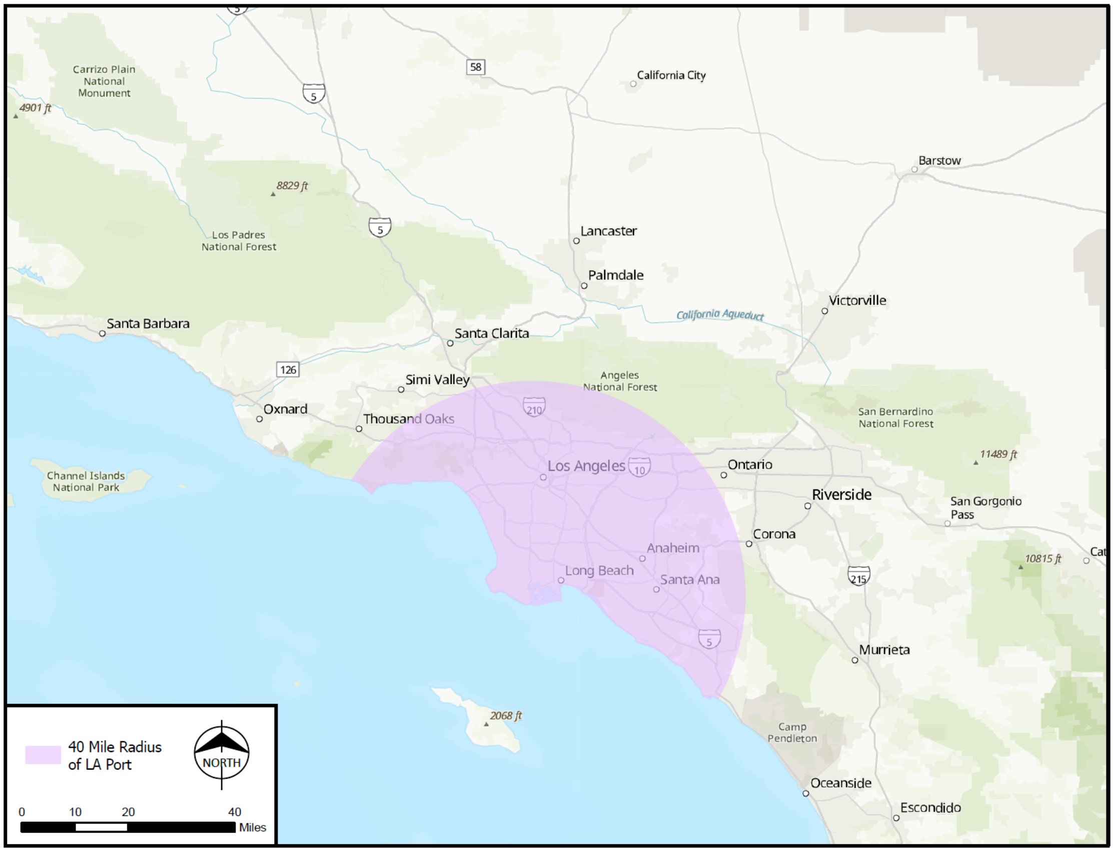
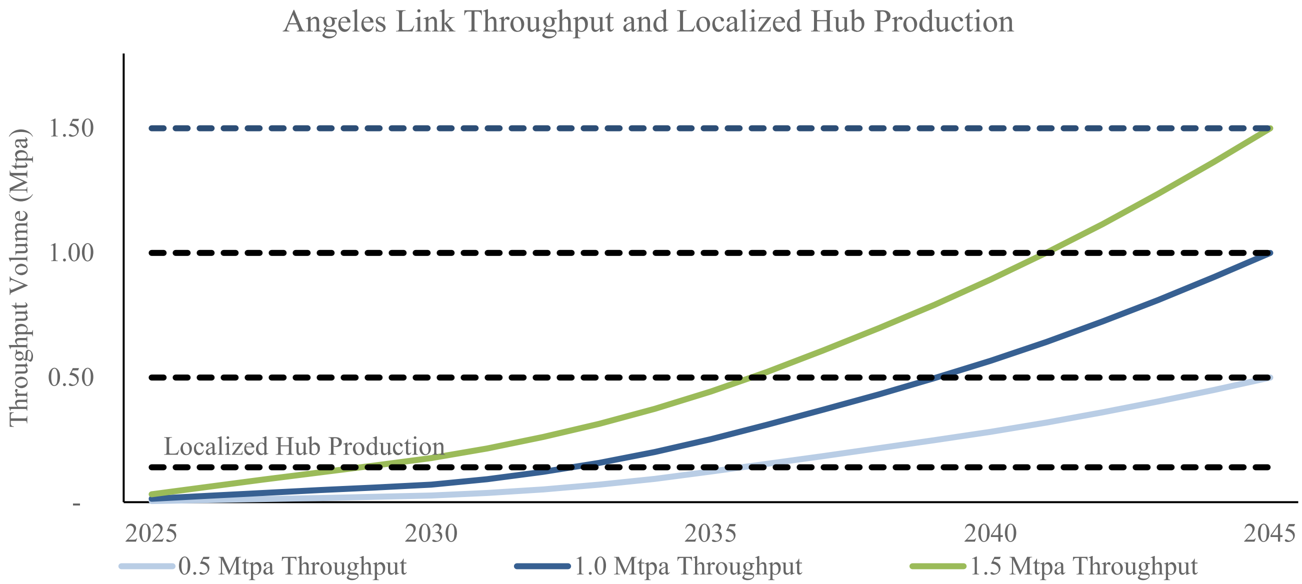


Figure 29: Angeles Link Throughput and Localized Hub Production



7.2. Results Tables

7.2.1. Levelized Cost of Delivered Hydrogen (see Cost Effectiveness Study)

Table 17: Levelized Cost of Delivered Hydrogen by Alternative and Value Chain Segment

Cost Component ($/Kg$H_2$)	Angeles Link Pipeline System	Liquid Hydrogen Shipping	In-Basin Production w/Power T&D	Methanol Shipping	Gaseous Trucking	Localized Hub	Liquid Trucking
Delivery[204]	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Regasification or Hydrogen Reconversion[205]	N/A	$0.18	N/A	$1.56	N/A	N/A	$0.18
Storage[206]	$0.28	$1.65	$2.31	$2.31	$0.28	$2.31	$0.29
Transmission	$0.67	$0.29	$1.76	$0.04	$6.53	N/A	$7.41
Liquefaction or Methanol Production	N/A	$1.42	N/A	$0.64	N/A	N/A	Inc. in Transmission
Production[207]	$4.47	$4.59	$4.58	$4.57	$4.51	$9.64	$4.66
Total LCOH	**$5.50**	**$8.21**	**$8.73**	**$9.20**	**$11.40**	**$12.03**	**$12.62**

Notes: Reflects costs from Scenario 7 (corresponding to Design Study, Configuration A, single run scenario) for 1.5 Mtpa. Production is assumed to begin in 2030 to take advantage of tax incentives, including Production Tax Credits (PTC) for hydrogen (45V)[208] and power (45Y)[209], which provide $3 per kg$H_2$ and $0.028 per kWh for ten years. Storage assumptions were based on proximity to production sites, and the geographic footprint under consideration for storage in the Production Study. [210] For Angeles Link and the trucking alternatives (gaseous and liquid), identified routes allowed for access to underground storage sites, therefore, underground storage costs were assumed. Delivery alternatives with production sites that did not overlap with the identified geological storage sites, were assumed to rely on above ground storage. These alternatives include shipping, in-basin production with T&D, and localized hub. The shipping solutions include the costs of specialized handling required to deliver methanol and liquid hydrogen. The cost for liquefaction in the liquid hydrogen trucking alternative is included as a part of transmission costs.

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[204] Assumes a delivery line of approximately 80-miles.

[205] Regasification or hydrogen reconversion is part of the transportation process for liquid hydrogen shipping, methanol shipping, and liquid hydrogen trucking. These processes are not used for the other Hydrogen Delivery Alternatives.

[206] Underground storage was assumed for Angeles Link and the trucking options. All other Hydrogen Delivery Alternatives were assumed to have above-ground storage due to a lack of nearby underground storage options.

[207] Assumes production tax credits (PTC) in place

[208] Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property.

[209] Section 45Y Clean Electricity Production Credit and Section 48E Clean Electricity Investment Credit.

[210] For additional details on the rationale for Storage assumptions for each alternative please refer to Cost Effectiveness Study Appendix 7.5.1. The storage solution selected reflects the best available for a like for like comparison.

LCOH Calculation

To compare $/kg cost across the different Delivery Alternatives, all capital expenditures (CapEx) and operating expenditures (OpEx) over the lifetime of the system should be considered. The pipeline LCOH considers the lifetime costs from production, transmission, storage, and distribution. For Delivery Alternatives, the costs may also include loading, trucking, shipping, liquefaction, compression, power transmission, and other specialized handling like methanol conversion and reconversion (reforming).

LCOH Formula

$$LCOH_{\substack{Post-Tax, \\ Levered}} = \frac{\sum_{i=1}^{T} \frac{(Opex^{i} + Capex_{L}^{i} + Interest^{i} + Principal^{i})}{(1+r)^{i}}}{\sum_{i=1}^{T} v^{i} \left(\frac{1+\text{inf}}{1+r}\right)^{i}}$$ [211]

Parameter	Description
OpEx	Operating Expenses
CapEx	Capital Expenses
DTS	Depreciation Tax Shield
L	Levered
T	Total years of Project Lifetime
Inf	Rate of Inflation (%)
r	Discount Rate (%)
v	Volume of Hydrogen / Ammonia
Interest	Interest Loan Payments
Principal	Principal Loan Payment
i	Time, assumes each year of the operational or economic life of the relevant hydrogen infrastructure
∑	Mathematical shorthand notation to indicate the sum of a number of similar terms, in this case the sum of all years of the operational or economic life of the relevant hydrogen infrastructure

[211] Wood Mackenzie Lens Hydrogen.

7.3. Key Considerations

7.3.1. Ammonia Considerations

Ammonia shipping, with ammonia production in Central and Northern California with access to ports, was evaluated as a potential alternative for hydrogen delivery. To compare ammonia shipping to the other alternatives on a like for like basis, the options and alternatives evaluation assumed hydrogen and ammonia production for this alternative is powered from non-grid interconnected solar generation facilities. As discussed in Section 4.3.1.2, there are many reasons why non-grid interconnected solar power generation is incompatible with the technical requirements of ammonia production. The incompatibility is largely driven by the requirement of the Haber-Bosch process to receive a steady 24/7 power and hydrogen supply.

However, there are several supply chain configurations that may or may not be applicable or available in California that are in development across projects globally to support a more consistent supply of low-carbon hydrogen and attempt to bypass the inherent technical constraints present for a project aiming to produce 100% renewable ammonia via solar power. These configurations often come with significant added costs and are typically focused on: (1) increasing the availability of renewable power generation, and (2) increasing the availability of renewable hydrogen.

Renewable Power Availability

- Combining wind with solar (in certain advantaged regions with high-quality and complimentary wind and solar availability)
- Combining batteries with solar
- Oversizing solar and/or wind power generation
- Procuring renewable power purchase agreements (PPAs) (although the availability of renewable PPAs at the scale required for operating a world-scale ammonia production facility may be costly and challenging)

Renewable Hydrogen Availability

- Oversizing electrolyzer capacity (would also require commensurate renewable power generation to be developed)

- Developing high-capacity hydrogen storage solutions (requires access to geological hydrogen storage with a high level of deliverability at a high quality)

7.3.2. CCS Considerations

D.22-12-055, OP 5(e), requires SoCalGas to demonstrate how the activities of Phase 1 "consider and evaluate Project alternatives, including … other decarbonization options..."[212] While electrification is the primary non-hydrogen decarbonization option mentioned in the Decision, CCS was also determined to be a non-hydrogen decarbonization option for evaluation in this study.[213] CCS could play an important role in supporting California's decarbonization targets in several sectors, as the CARB Scoping Plan accounts for CCS to be implemented in the majority of petroleum refining operations by 2030 and 40% of cement operations by 2035.[214]

For the purpose of this study, the assessment of CCS was primarily conducted on a use case level in comparison with hydrogen (e.g., cement kilns run on clean renewable hydrogen vs. natural gas with CCS), with certain system-level assumptions made where relevant (e.g., scalability considerations related to the need to aggregate point source emissions from large facilities or large clusters of smaller facilities). For CCS to be successfully implemented at scale and considered as an alternative to Angeles Link, there are multiple important economic and non-economic considerations at the individual site, the sector, and the regional level (see a non-comprehensive list of examples in Table 18 below). While many of these considerations were incorporated into the analysis in this study, it was outside the scope of this study to conduct a comprehensive analysis of the prospects for CCS in California.

[212] As described in D.22-12-055, p. 75.
[213] As set out in the glossary of terms in Section 0.2, for purposes of this study, CCS refers to the capture of CO_2 from point sources (not direct air capture), with sequestration in geologic formations (such as depleted oil and gas reservoirs and saline formations).
[214] California Air Resources Board. Retrieved from 2022 Scoping Plan for Achieving Carbon Neutrality, p. 74, 77.

Table 18: CCS Considerations

Level of Value Chain	Considerations
Site level	• Plants require physical space within the plant boundary to add capture equipment, which is often a challenge for CCS retrofits • The ability to support the capital investment and operating costs of CCS depends on the utilization and remaining operational life of the site • In the absence of access to CO_2 infrastructure, the scale of CO_2 captured at an individual site may not support the costs of infrastructure development for transport and sequestration • Additional energy is required to operate capture equipment, increasing the overall energy intensity of operations
Sector level	• Certain sectors have specific factors that make CCS an attractive pathway. The cement sector has a specific state policy target for decarbonization (SB 596) but few other decarbonization pathways that can address the full scope of a facility's emissions to the degree CCS can • Certain sectors face challenges for CCS implementation; for example, CCS is not technically viable as a solution to address tailpipe emissions in the mobility sector
Regional level	• The ability to access to open access regional CO_2 pipeline and storage infrastructure is required in many cases to make CCS viable • The aggregation of either large point sources or large clusters of smaller point sources is required in many cases to make CCS viable • The cost considerations for CCS on a use case level are highly sensitive to the cost of fuel, should a carbon price or tax mechanism (or other market factors) increase the regional price of natural gas, the commercial viability of CCS may be greatly reduced

Ultimately, CCS provides a potential pathway among a portfolio of solutions, including clean renewable hydrogen, to help contribute to the state's carbon neutrality targets by 2045. If CO_2 transport and sequestration infrastructure is developed at scale, and in the absence of new carbon taxes or other policy mechanisms to penalize residual emissions, CCS could be cost-effective relative to alternatives like clean renewable hydrogen for certain end users. However, CCS is only technically and commercially feasible under certain site-level and regional considerations, including the availability of space for additional equipment within the plant boundary, access to transport and sequestration infrastructure, and regional concentration of point source emissions at scale. The CARB Scoping Plan forecasts a role for CCS in specific sectors (including refineries and cement), but clean renewable hydrogen may be a better pathway for other sectors (including mobility and power generation), and for specific refineries and cement facilities where conditions are less favorable to CCS implementation.

7.3.3. System-Level Electrification Considerations

D.22-12-055, OP 5(e), requires SoCalGas to demonstrate how the activities of Phase 1 "consider and evaluate Project alternatives, including … other decarbonization options such as electrification."[215] For the purpose of this study, an electrification alternative refers to a combination of system level transformation and use case level technology changes, including the grid infrastructure required to support growing electric load.

To assess system-level electrification as an alternative to Angeles Link, the Alternatives Study first investigated whether electrification was a viable decarbonization alternative for the end-use sectors targeted by Angeles Link. Electrification is a decarbonization option if the electricity delivered is clean and reliable; however, the current carbon intensity[216] of California's average grid electricity is estimated to be 80.55 gCO_2e/MJ[217] and primarily driven by remaining fossil fuel-based generation mix. The CARB Scoping Plan commits to "adding four times the solar and wind capacity by 2045 and about 1,700 times the amount of current hydrogen supply", while noting that "electrification is not possible in all situations", and residual emissions will remain from difficult to decarbonize industries such as cement, internal combustion vehicles still on the road, and global warming chemicals used as refrigerants.[218] As the electric grid continues to integrate more renewables at scale and existing fossil fuel based generation retires, California needs clean firm dispatchable power to meet the increased electric load, ramping, and system reliability needs.[219,220,221]

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[215] As described in D.22-12-055, p. 75.

[216] For smart charging or smart electrolysis in California, see California Air Resources Board, Low Carbon Fuel Standard Annual Updates to Lookup Table Pathways.

[217] Annual update to carbon intensity (CI) values for Lookup Table electricity pathways under the Low Carbon Fuel Standard (LCFS). See Low Carbon Fuel Standard, Annual Updates to Lookup Table Pathways.

[218] California Air Resources Board. Retrieved from 2022 Scoping Plan for Achieving Carbon Neutrality, p.8.

[219] EDF, California needs clean firm power, and so does the rest of the world.

[220] The CEC's 2023 Integrated Energy Policy Report (IEPR) identifies clean renewable hydrogen's potential to support electric generation, transportation electrification, and industrial decarbonization. (CEC, 2023 Integrated Energy Policy Report, Chapter 2: Potential Growth of Clean and Renewable Hydrogen, available at: 2023 Integrated Energy Policy Report.

[221] Governor Gavin Newsom, Building the Electricity Grid of the Future: California's Clean Energy Transition (May 2023), at 6, available at: Building the Electricity Grid of the Future: California's Clean Energy Transition Plan ("[C]lean sources of electricity like solar and wind energy are more variable and more intermittent. We will not be able to build a reliable, clean electric grid using solar and wind energy alone. California needs more diverse clean energy resources – including batteries, clean hydrogen, and long duration storage - and a wide range of technologies and resources to meet the unprecedented growth in demand for electricity at all hours of the day and different times of year.").

A detailed assessment of system-level electrification would need to consider all aspects of the electric system value chain, with examples shown in Table 19 below:

Table 19: Examples of Analysis Required for a Full Assessment of System-level Electrification

Electrification Value Chain	Analysis Needed
Demand	• Electrification adoption analysis by sector and hourly load forecast.
Dispatchable Supply	• Resource assessment and incremental deployment forecast for wind, solar, and battery storage. • Power system dispatch modeling to provide hourly supply/demand balancing within system reliability requirements.[222]
Infrastructure	• Power flow modeling to determine ability of current and planned T&D investments to accommodate additional generation and load vs. the need for new T&D investment. • Sizing, routing, and cost of incremental T&D infrastructure.

For the purpose of this study, the detailed analyses above were deemed out of scope, and assessment of electrification was primarily conducted on a use case level (e.g., FCEV vs. BEV for heavy-duty vehicles), with certain system-level considerations incorporated into the use case level assessments where relevant (e.g., reliability and resiliency and scalability considerations). A broader discussion of the demand, dispatchable supply, and infrastructure considerations of system-level electrification is included below based on a high-level review of existing research, third-party studies, and California's clean energy and environmental policies.

Electricity Demand Considerations for System Electrification

This study evaluates electrification as an alternative to hydrogen by assuming that projected hydrogen demand in the mobility, power generation, and industrial sectors is served with electricity rather than hydrogen supplied by Angeles Link. Electrification of heavy-duty transport and high-temperature industrial heat applications would impose significant demand for clean electricity on the California power system, challenging its ability to meet reliability and resiliency requirements.

[222] A detailed power modeling study would need to be conducted to determine the clean electricity portfolios capable of meeting demand while maintaining system reliability. This analysis is typically conducted using specialized software to simulate hourly demand and the specific power plants built each year and dispatched in each hour to minimize system costs while meeting reliability requirements. This level of analysis was not in the scope of this study.

Electrification is widely recognized as a favorable decarbonization pathway for many sectors, but it is also known to be less technically feasible in sectors like long-haul, heavy-duty trucking, and high-heat industrial processes. Delivering clean renewable hydrogen via Angeles Link would offer a feasible technology transition based on existing business models, while electrification could create operational and business model challenges for fleet owners. This is supported by the CARB Scoping Plan, which projects hydrogen to serve 40% of medium- and heavy-duty transportation demand by 2045. Additionally, the relatively high electricity tariffs in California mean hydrogen are projected to be more cost-effective for industrial applications. See Sections 4.3.2.1.2 and 4.4.2.2.1 for additional findings related to the evaluation of electrification for specific end use segments.

Electricity Supply Considerations for System Electrification

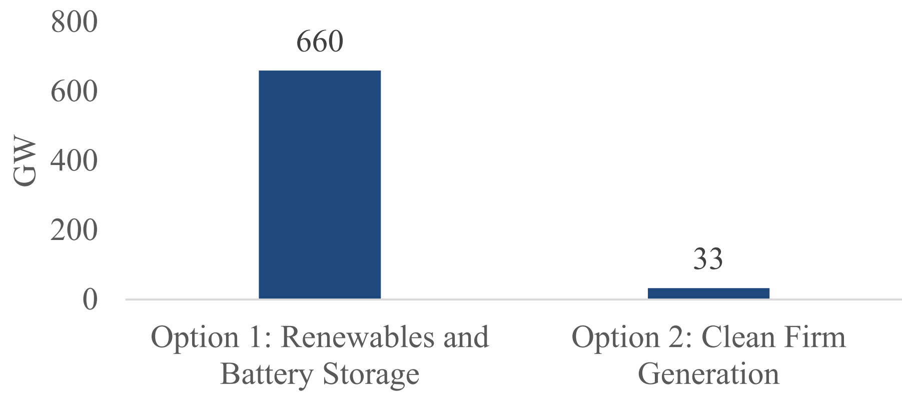
Supply refers to the electricity generation and storage portfolio needed to support decarbonization of the power system, including the ability of that portfolio to match demand on an hourly basis, supporting system reliability. Other carbon-free alternatives like nuclear power generation, hydro power generation, geothermal power generation, and biomass power generation are not forecasted to play a large role in the California power system.[223] However, renewables and battery storage alone may not be able to provide the clean firm generation (available to be dispatched 24/7) and long-duration storage (to compensate for days or weeks of lower renewable output) needed to fully decarbonize the California power system and meet the state's clean energy targets. Additional information on the role of lithium-ion batteries and the need for LDES in California is provided in Appendix 7.3.4.

- **Relying solely on solar, wind, and battery storage in California would require a significant overbuild of California generation capacity.** Sufficient supply of carbon-free generating resources needs to be available to achieve California's decarbonization targets. A recent power modeling study[224] analyzed power system decarbonization pathways for California and determined that the pathway relying only on solar, wind, and battery storage (Option 1 in Figure 30 below) would require a significant overbuild of generation compared to the pathway that included renewables and clean firm generation (Option 2 in Figure 30 below). To meet California's decarbonization targets, the renewables and storage-only

[223] California Air Resources Board. Retrieved from 2022 Scoping Plan for Achieving Carbon Neutrality.
[224] EDF, California needs clean firm power, and so does the rest of the world.

portfolio (Option 1) required 660 GW of generation and storage capacity in California, or about half of current U.S. installed renewable capacity, compared to only 33 GW of capacity using clean firm generation in California (Option 2), as seen in Figure 30 below.

Figure 30: New Power Generation Capacity Deployment Required to Meet SB 100 Target[225]



- **Clean firm resources can provide reliability for the California grid**. Clean firm generation plays a critical role in maintaining system reliability while supporting full decarbonization of power supply. Development of roughly 25-40 GW of firm dispatchable power capacity would significantly eliminate the large capacity needs of additional and solar and wind resources. [226]

Wind, solar, and battery storage will be deployed at scale in California, but there remains a need for clean firm generation and long-duration storage in the power system to support reliability. Alongside wide-scale deployment of renewables and battery storage, the power system needs clean firm generation and long-duration storage resources—both of which can be supported by Angeles Link as part of a clean, reliable hydrogen system. Advancing a portfolio of clean firm power generation technologies including hydrogen can play an important role in maintaining system reliability while supporting full decarbonization of the power supply. This is supported by the CARB Scoping Plan, which includes 9

[225] EDF, California needs clean firm power, and so does the rest of the world.
[226] Ibid.

GW of hydrogen turbine capacity by 2045,[227] and the approval of plans to convert the Scattergood Generating Station to run on green hydrogen by LADWP.[228]

Electric T&D Infrastructure Considerations for System Level Electrification

Infrastructure refers to the T&D equipment required to deliver electricity to end users. As of 2023, California had 25,000 miles of electric transmission lines in operation.[229] Adding the roughly 17 to 50 TWh of new electric demand that would have been served by Angeles Link and several hundred GWs of new supply would require significant new electric transmission infrastructure to reliably serve demand.

- **Current electric transmission investment plans are already ambitious without accounting for additional levels of electrification in sector use cases targeted by Angeles Link.** The latest transmission infrastructure plan released by the CAISO includes 45 transmission projects designed to support reliability of the grid, totaling an investment of $7.3 billion by 2033.[230] Reliability planning for incremental electrification would require additional resources and likely significant additional infrastructure given the scale of new generation and new load being discussed.
- **Transmission lines require more land to deliver the same amount of energy compared to hydrogen pipelines.** High-voltage transmission lines carry less energy than hydrogen pipelines. For example, a 500 kV electric transmission line transports approximately 25% of the energy compared to the proposed capacity of the Angeles Link pipeline.[231] To deliver the same amount of energy as Angeles Link into the L.A. Basin, additional circuits, towers, transmission lines, and associated land would be needed. While power system studies would be required to analyze the impact of additional electrification on existing and planned transmission infrastructure, the increased land needed due to lower energy carrying capacity presents scalability challenges for electric transmission lines.

The electricity system needs substantial investment in new T&D infrastructure to accommodate planned increases in electric generation and load growth. The additional infrastructure needed to support a higher

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[227] California Air Resources Board. Retrieved from 2022 Scoping Plan for Achieving Carbon Neutrality.
[228] LADWP Scattergood Modernization Project.
[229] California Public Utilities Commission. (n.d.). CPUC Undergrounding Programs Description.
[230] California ISO. CAISO 2022-2023 Transmission Plan.
[231] National Park Service. (n.d.). Environmental Impact Statement: Powering the Grid.

level of electrification of the use cases targeted by Angeles Link would increase the burden on already ambitious power T&D investment plans. Angeles Link provides a cost-effective energy transportation method and mitigates the need for additional power infrastructure. Multiple studies based on a variety of high-voltage AC and DC electric transmission systems and hydrogen pipeline comparisons have found that transmission lines are more expensive per unit of energy delivered than hydrogen pipelines due to the lower energy-carrying capacity of transmission lines.[232,233] This conclusion is supported by the Cost Effectiveness Study's finding that the LCOH of Angeles Link[234] is lower than the LCOH of an alternative that would generate renewable electricity outside the basin, transport that electricity into the basin using electric transmission lines, and produce hydrogen in-basin.

[232] Oxford Institute for Energy Studies. Hydrogen pipelines vs. HVDC lines: Should we transfer green molecules or electrons?
[233] NREL. Cost of long-distance energy transmission by different carriers. iScience.
[234] Refer to Cost Effectiveness Study.

7.3.4. Rationale for Selecting 12-Hour Lithium-ion Battery Storage as Electrification Alternative for Power Use Case

In the Non-Hydrogen Alternatives section, Angeles Link is assessed for the power sector based on hydrogen-fueled combustion turbines (hydrogen turbines), and electrification is evaluated based on a 12-hour lithium-ion battery energy storage facility. The 12-hour lithium-ion battery storage was selected as the most appropriate comparison to the hydrogen turbines to serve inter-day loads, and the required ramping needs to support reliability requirements lasting longer than a few hours.

With an increasing share of renewables displacing natural gas generation in California, clean firm generation and LDES resources are needed to balance the shortfall in renewables output due to extreme weather, demand fluctuations, and seasonal patterns in output. Studies assessing the reliability of California's grid have projected that solar and wind resources may experience "resource drought" events.[235] These events, characterized by sustained low output, can last one to two days and occur up to 30 times throughout the year. LDES may be a good solution for these events. Longer duration battery technologies (12-hour discharge duration) offer partial grid support solutions to mitigate such resource-drought events. This is supported by a retrospective analysis of how LDES could have performed during the 2020 California heat wave, which showed that energy storage with 12-plus-hour duration would have effectively managed the lower renewable energy output.[236]

LDES technologies can be characterized by their ability to serve different duration use cases, including inter-day and multi-day durations. Inter-day LDES technologies comprise mechanical storage options, such as pumped hydro, compressed air, liquid air energy storage, and certain types of flow batteries, typically lasting between 10 and 36 hours. Multi-day LDES comprises a variety of thermal and electrochemical technologies and electrolytic fuels with durations ranging from 36 to 160 hours. Many LDES technologies are not yet technologically mature to be deployed at commercial scale and need further advancements to become commercially viable in the future. Furthermore, the discharge capabilities of LDES technologies suggest they are likely to play a different role when compared to shorter duration lithium-ion battery technologies. While lithium-ion is expected to remain a dominant

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[235] Wind and Solar Resource Droughts in California. Rinaldi, Katherine Z., et al. s.l.: Environmental Science & Technology.
[236] California Energy Commission. Retrieved from Assessing the Value of Long-Duration Energy Storage in California.

energy storage technology for intra-day requirements and fast-response grid services, LDES technologies will serve the emerging inter-day and multi-day needs of the decarbonizing power system.

Of the handful of emerging LDES technologies, compressed air energy storage (CAES) and vanadium redox flow batteries (VRFB) are the most mature. CAES and VRFB are commercially available at pilot scale, particularly in China. Recently, Hydrostor announced a 500 MW CAES facility in California and has secured an offtake agreement from a community choice aggregator.[237] However, these technologies face certain limitations. They are geographically constrained and can be subject to price volatility for key raw materials (such as vanadium for VRFB), which restricts their deployment. Figure 31 below illustrates the relative capabilities of a variety of storage technologies.

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[237] [Hydrostor Compressed Air Energy Storage in California.](#)California Air Resources Board. (2022). Retrieved from 2022 Scoping Plan for Achieving Carbon Neutrality: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

California Energy Commission. (2023). Retrieved from Assessing the Value of Long-Duration Energy Storage in California: https://www.energy.ca.gov/sites/default/files/2024-01/CEC-500-2024-003.pdf

Driscoll, W. (2023). Retrieved from 500 MW compressed air energy storage project in California secures offtaker: https://pv-magazine-usa.com/2023/01/13/500-mw-compressed-air-energy-storage-project-in-california-secures-offtaker/

Rinaldi, K. Z., Dowling, J. A., Ruggles, T. H., Caldeira, K., & Lewis, N. S. (n.d.). Wind and Solar Resource Droughts in California.

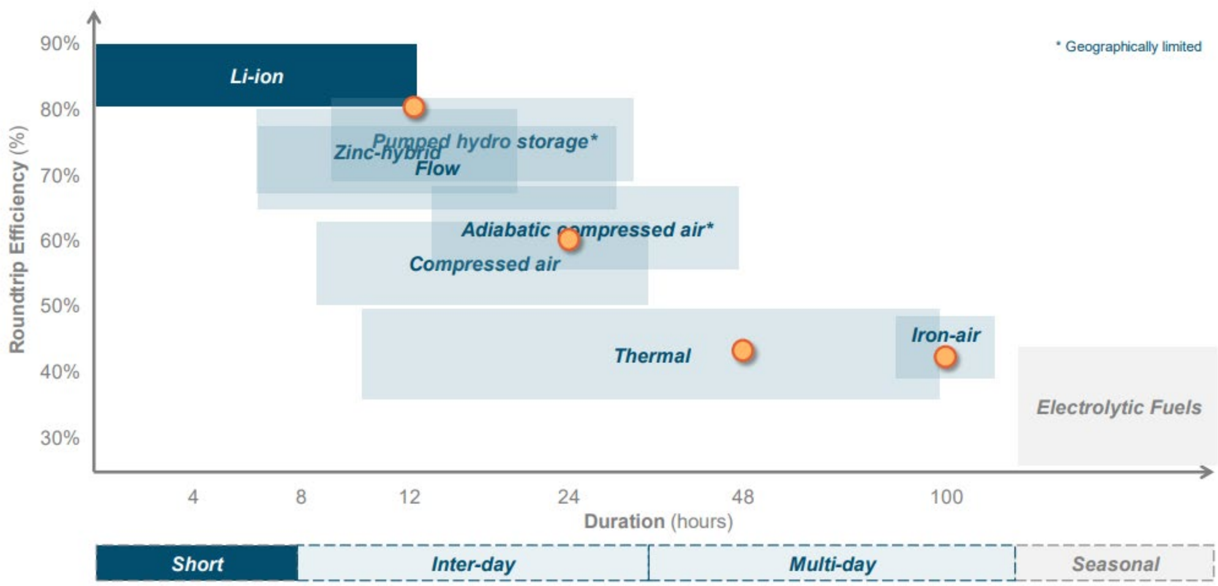
California Air Resources Board. (2022). Retrieved from 2022 Scoping Plan for Achieving Carbon Neutrality: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

California Energy Commission. (2023). Retrieved from Assessing the Value of Long-Duration Energy Storage in California: https://www.energy.ca.gov/sites/default/files/2024-01/CEC-500-2024-003.pdf

Driscoll, W. (2023). Retrieved from 500 MW compressed air energy storage project in California secures offtaker: https://pv-magazine-usa.com/2023/01/13/500-mw-compressed-air-energy-storage-project-in-california-secures-offtaker/

Rinaldi, K. Z., Dowling, J. A., Ruggles, T. H., Caldeira, K., & Lewis, N. S. (n.d.). Wind and Solar Resource Droughts in California.

Figure 31: Round-trip Efficiency of Storage Technologies Categorized by Duration[238]



Lithium-ion has and will continue to play a critical role in system reliability for short and inter-day durations offering higher round trip efficiencies. However, as renewable energy penetration increases, other LDES technologies will play an important role beyond what traditional lithium-ion technology can provide. For purposes of Phase 1 feasibility analysis, a 12-hour lithium-ion battery[239] stack (made up of three 4-hour stacks) was used as an electrification end-use alternative for comparison.

[238] California Energy Commission. Retrieved from [Assessing the Value of Long-Duration Energy Storage in California.]

[239] This is in line with a recent study from the CEC, which also used 12-hour lithium-ion as a benchmark against emerging LDES technologies, California Energy Commission. Retrieved from [Assessing the Value of Long-Duration Energy Storage in California.]

7.4. References for Alternatives Assessments

7.4.1. Technology Readiness Levels for Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives

Technology readiness level scores discussed throughout this study are adopted from IEA's Clean Tech Guide.

Table 20: IEA's Technology Readiness Levels [240]

TRL Score	Category	Description
1	Concept	**Initial idea:** Basic principles have been defined
2		**Application formulated:** Concept and application of solution have been formulated
3		**Concept needs validation:** Solution needs to be prototyped and applied
4	Small Prototype	**Early prototype:** Prototype proven in test conditions
5	Large Prototype	**Large prototype:** Components proven in conditions to be deployed
6		**Full prototype at scale:** Prototype proven in test conditions
7	Demonstration	**Pre-commercial demonstration:** Prototype working in expected conditions
8		**First-of-a-kind commercial:** Commercial demonstration, full-scale deployment in final conditions
9	Market Uptake	**Commercial operations:** Solution is commercially available, needs evolutionary improvement to stay competitive
10		**Integration needed at scale:** Solution is commercial and competitive but needs further integration efforts
11	Mature	**Proof of stability reached:** Predictable growth

[240] ETP Clean Energy Technology Guide – Data Tools - IEA.

7.4.2. Select California State/Local Policies Evaluated

Table 21: Select California State/Local Policies Evaluated for Non-Hydrogen Alternatives

State Policy	Description	Applicable Use Cases
SB 100 [241]	100% renewable or zero-carbon electricity sales in California by 2045	Power and Cogeneration
Renewable Portfolio Standard [242]	California regulations require utilities to procure 60% of retail sales through RPS eligible resources by 2030	
LA100 [243]	L.A.'s goal of reliable, 100% renewable electricity by 2045	
Cap and Trade [244]	Establishes a declining limit on major GHG emissions sources throughout California; provides a statewide system of allowances for emissions	
SB 905 [245]	Creation of a carbon capture regulatory framework to adopt regulations for new technologies	Power, Cogeneration, Refineries, and Cement
Pipeline Moratorium [245]	State law banning flow of carbon dioxide through new pipelines until the finalization of safety regulations by the federal government	
Executive Order N-79-20 [246]	100% of in-state sales of new passenger cars and trucks should be zero-emission by 2035; 100% of medium- and heavy-duty vehicles should be zero-emission by 2045	Mobility
Advanced Clean Fleets and Advanced Clean Trucks [247]	State requirement for fleets and trucks to be zero-emission vehicles by 2036	
Innovative Clean Transit [248]	Regulation for all public transit agencies to gradually transition to 100% zero-emission bus fleet	
Low Carbon Fuel Standards [249]	Regulation designed to incentivize and encourage the use of low-carbon transportation fuels in California	Mobility and Refineries
Assembly Bill 32 [250]	Mandates that California reduce its GHG emissions to 1990 levels by 2020	Power, Mobility, Cogeneration, Refineries, Food & Beverage, and Cement
PR-1153.1[251]	L.A. County Air Quality Management District methane and NOx emissions regulation for the Food & Beverage sectors	Food & Beverage
Senate Bill 596 [252]	Requires cement producers in California to reduce their GHG emissions in the production phase by 40% below 1990 levels by 2030, with the goal of achieving zero emissions by 2045	Cement

[241] California Senate Bill 100.
[242] California Public Utilities Commission, Renewables Portfolio Standard (RPS) Program.
[243] LA100 Equity Strategies, 100% Renewable Energy Study.
[244] California Air Resources Board, Cap-and-Trade Program.
[245] California Senate Bill 905.
[246] Executive Order N-79-20.
[247] California Air Resources Board, Advanced Clean Fleets Regulation Summary.
[248] California Air Resources Board, Innovative Clean Transit.
[249] California Air Resources Board, Low Carbon Fuel Standard.
[250] California Air Resources Board, AB 32 Global Warming Solutions Act of 2006.
[251] South Coast AQMD, Proposed Amended Rule 1153.1.
[252] Bill Text: CA SB596 | 2021-2022 | Regular Session | Chaptered | LegiScan.

7.4.3. Environmental Analysis of Alternatives

Alternatives that met the criteria in the Alternatives Study were carried forward to the Environmental Analysis. Results of the Environmental Analysis are noted in Table 22 below.

Table 22: High-Level Environmental Analysis of Alternatives

Assessment Criteria[253]	High-Level Assessment
Air Quality • Conflict with or obstruct implementation of an applicable air quality plan; result in a cumulatively considerable net increase of criteria pollutants; expose sensitive receptors to pollutant concentrations; result in other emissions adversely affecting a substantial number of people	• The project and alternatives are expected to have construction and operational impacts to air quality. • For example, for various alternatives, impacts may occur from construction and operation activities, including pipeline and electric transmission line construction, vehicle miles traveled from truck trips, nautical miles traveled from ships, and from construction of liquefaction and regassification facilities.
Biological Resources • Direct or indirect impacts to candidate, sensitive, or special status species or modification of their habitat, impacts to any riparian habitat, wetlands, or other sensitive natural community; interference with movement of native resident or migratory fish or wildlife species or with established wildlife corridors; conflict with local policies protecting biological resources, provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or other approved habitat conservation plan.	• The project and alternatives are expected to have construction and operational impacts to biological resources. • For example, for various alternatives, impacts may occur, including for pipeline and electric transmission line construction, vehicle miles traveled from truck trips, and nautical miles traveled from ships. • For certain construction activities, potential impacts may occur in previously-disturbed areas. • Potential impacts during operational phases of certain facilities, such as underground pipelines or electric transmission lines during periodic operations and maintenance activities.
Cultural Resources • Cause substantial adverse change(s) in the significance of historical and/or archaeological resources, or disturbance of human remains.	• The project and alternatives are expected to have construction and operational impacts to cultural resources. • For example, for various alternatives, impacts may occur from pipeline and electric transmission line construction.

[253] The high-level environmental assessment uses applicable questions from the CEQA Guidelines Appendix G as a framework to evaluate potential impacts in selected resource areas. Findings are preliminary and high level and therefore 1) do not represent if an impact is significant from the CEQA/NEPA perspective nor address the magnitude of the impact; 2) do not capture all impact areas that will be evaluated in a CEQA/NEPA document; and 3) do not account for the project's or alternatives' benefits, including those benefits from the use of the clean energy delivered by the project or alternative.

Assessment Criteria[253]	High-Level Assessment
	• For certain construction activities, potential impacts may occur in previously-disturbed areas. • Potential impacts may occur during periodic operational and maintenance phases of certain facilities, such as underground pipelines or electric transmission lines.
Energy • Wasteful, inefficient, or unnecessary consumption of energy resources; conflict with state or local plans for renewable energy or energy efficiency.	• The project and alternatives are not expected to result in the wasteful, inefficient, or unnecessary consumption of energy. • Potential impacts from alternatives, such as trucking and shipping, may require energy consumption through diesel fuel. However, over time trucks and ships may transition to electric, hydrogen fuel-cells, or lower carbon intensive fuels. • For the project and some alternatives, periodic operations and maintenance could result in limited energy consumption. • The project and certain alternatives may temporarily conflict with state or local plans for renewable energy or energy efficiency during construction. For example, potential conflicts could occur during construction of pipelines, vehicle miles traveled from trucks, and nautical miles traveled from ships.
Greenhouse Gas Emissions • Generate GHG emissions, either directly or indirectly, including conflicts with applicable plans, policies, or regulations for reducing GHG emissions.	• The project and alternatives are expected to have construction and operational impacts related to GHG emissions. • For example, for various alternatives potential impacts are expected to occur from pipeline and electric transmission line construction, vehicle miles traveled from trucks, nautical miles traveled from ships, and construction of liquefaction and regassification facilities.
Hydrology and Water Quality • Cause water quality degradation; groundwater depletion or recharge; alter existing drainage patterns; location within flood hazard; conflict with Water Quality Control or Ground Water Management plans.	• The project and alternatives are expected to have construction and operational impacts related to hydrology and water quality. • For example, for various alternatives, potential impacts are expected to occur from pipeline construction and construction of liquefaction and regassification facilities. • Construction activities for the project and alternatives could cause short-term water quality impacts, and/or could potentially

Assessment Criteria[253]	High-Level Assessment
	conflict with water quality control or ground water management plans. • Construction activities for several facilities, such as underground pipelines, could be constructed in floodplains and/or cause erosion.
Land Use • Physically divide a community; conflict with existing plans, policies, or regulations.	• The project and alternatives could have construction and operational impacts, and associated impacts to communities, related to land use, such as electric transmission lines for the power transmission & distribution or electrification alternatives. • Depending on location of pipeline routes and other facilities, potential conflict could occur with existing land use plans, policies, or regulations.
Tribal Cultural Resources • Cause a substantial adverse change in the significance of a tribal cultural resource.	• The project and alternatives may have construction and operational impacts to tribal cultural resources. • For example, for various alternatives, potential impacts may occur in previously-disturbed areas, from pipeline and electric transmission line construction, construction of liquefaction and regassification facilities. • Potential impacts during periodic operational and maintenance phases of certain facilities such as underground pipelines or electric transmission lines may occur.

July 2024

ANGELES LINK HIGH-LEVEL ECONOMIC ANALYSIS & COST EFFECTIVENESS REPORT DRAFT

SoCalGas commissioned this study from Wood Mackenzie. The analysis was conducted, and this report was prepared, collaboratively.

SoCalGas Wood Mackenzie

Table of Contents

0. Acronyms, Glossary, Tables & Figures

0.1. Acronyms and Abbreviations

ALMA	Angeles Link Memorandum Account
ARCHES	Alliance for Renewable Clean Hydrogen Energy Systems
BOP	Balance of Plant
BEV	Battery Electric Vehicle
B2B	Back to base
CARB	California Air Resources Board
CBOSG	Community-Based Organizations Stakeholder Group
CapEx	Capital Expenditure
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CO_2	Carbon Dioxide
DOE	Department of Energy
DTS	Depreciation Tax Shield
DOGR	Depleted Oil & Gas Reservoir
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
F&B	Food & Beverage
FCEB	Fuel Cell Electric Bus
FCEV	Fuel Cell Electric Vehicle
HDV	Heavy-Duty Vehicle
HVDC	High Voltage Direct Current
H_2	Hydrogen
IRR	Internal Rate of Return
ITC	Investment Tax Credit
Kg	Kilogram
LA	Los Angeles
LCFS	Low Carbon Fuel Standards
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Delivered Hydrogen
LDES	Long duration energy storage
LDV	Light Duty Vehicle
MDV	Medium Duty Vehicle
mi	Mile
MGD	Million gallons per day
MM	Million
$MMBtu_e$	Million Metric British Thermal Units equivalent
MTPA	Million tonnes per annum
MWh	Mega-watt hour
NPC	National Petroleum Council
NPV	Net Present Value
OEM	Original Equipment Manufacturer
O&M	Operations and Maintenance
OTR	On the road
OpEx	Operating Expenses
PAG	Planning Advisory Group
PTC	Production Tax Credit
REC	Renewable Electricity Certificate
RNG	Renewable Natural Gas
SJV	San Joaquin Valley
SMR	Steam methane reformer
SoCalGas	Southern California Gas Company
T&D	Transmission and Distribution
T-Bond	Treasury Bond
TCO	Total Cost of Ownership
UGSC	Underground Geologic Salt Caverns
VRFB	Vanadium Redox Flow Batteries
ZEV	Zero Emission Vehicle
T&S	Transport and Sequestration

0.2. Glossary of Terms

The following terms are used in this report. For the purposes of this report, the terms are used as follows:

Carbon capture and storage (CCS) – A set of technologies that remove CO_2 either from the atmosphere or from point sources. The captured CO_2 is then compressed and injected into deep underground geological formations (that may include depleted oil and gas reservoirs or saline formations) for permanent storage.[1] For purposes of this report, CCS alternatives are those that include the removal of CO_2 from point sources and permanent sequestration (not for use in oil and gas recovery).

Clean firm power - Zero-carbon power generation sources that can be relied on whenever and for as long as needed. Clean firm power sources do not depend on the weather like solar and wind do, and do not have limitations in duration of power production capabilities (as long as fuel is available).[2]

Clean renewable hydrogen – For purposes of Angeles Link Phase 1 studies, clean renewable hydrogen refers to hydrogen that is produced through a process that results in a lifecycle (i.e., well-to-gate) greenhouse gas (GHG) emissions rate of not greater than four kilograms of carbon dioxide-equivalent per kilogram of hydrogen produced and does not use any fossil fuel in its production process.[3]

Cogeneration – Combined heat and power (CHP), also referred to as cogeneration, is the simultaneous generation of useful heat and electricity from a single fuel source.[4]

Dispatchable energy/dispatchable generation – Resources that are classified as dispatchable by the scheduling coordinator (SC) or the California Independent System Operator (CAISO) and could include a variety of technologies: steam turbines; combustion turbines; combined cycle gas turbines; reciprocating engines; energy storage; dispatchable CHP; biomass and geothermal resources.[5]

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[1] SCALE Act, Senate Bill 799.
[2] SB100 Clean Firm Power Report Plus SI, p. 5.
[3] As defined in CPUC Decision (D.) 22-12-055.
[4] CPUC Combined Heat and Power (CHP) Program Overview.
[5] CPUC 2020 Qualifying Capacity Methodology Manual.

Electrification – Electrification refers to a combination of system level[6] transformation and use case level[7] technology changes including the grid infrastructure required to support growing electric load. The purpose of electrification in California is to reduce GHG emissions in carbon-intensive demand sectors by powering these sectors with electricity produced using zero carbon technologies over time.[8]

Electrolyzer – Electrolysis is the process of using electricity to split water into hydrogen and oxygen. This reaction takes place in a unit called an electrolyzer.[9]

Energy density – The amount of energy that can be stored per unit of volume or mass; higher energy density means more energy can be stored in a smaller volume or mass.[10]

***Levelized Cost of Electricity* (*LCOE*) –** Represents the average revenue per unit of electricity generated that would be required to recover the return on capital related to costs of building and operating a generating plant. LCOE is a summary metric to measure of the overall competitiveness of different generating technologies.[11]

Linepack – Gas linepack refers to the gas stored in gas pipelines due to the compressibility of the gas. As a form of gas energy storage, linepack can enhance system flexibility.[12]

Long-duration energy storage (LDES) – A portfolio of technologies that store energy over long periods for future dispatch and marked by duration of dispatch (e.g., multi-day and seasonal).[13]

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[6] System level electrification includes the incremental electricity generation, storage, and supporting upstream grid infrastructure requirements to meet wide-scale end use electrification needs.
[7] Use-case level electrification refers to replacing technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically powered equivalents, such as electric vehicles or heat pumps. More detail at IEA Electrification Overview.
[8] California Air Resources Board, 2022 Scoping Plan Documents.
[9] Hydrogen Production: Electrolysis, DOE Office of Energy Efficiency & Renewable Energy.
[10] Department of Energy Vehicle Technology Office definition, available at FOTW #1234, April 18, 2022: Volumetric Energy Density of Lithium-ion Batteries Increased by More than Eight Times Between 2008 and 2020 | Department of Energy.
[11] As defined in EIA Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022.
[12] As defined in Optimal scheduling of hydrogen blended integrated electricity–gas system considering gas linepack via a sequential second-order cone programming methodology. Wu et al.
[13] DOE Pathway to: Long Duration Energy Storage Commercial LiftOff.

Levelized Cost of Delivered Hydrogen (LCOH) – Reflects the unit cost of hydrogen based on the return on capital related to the cost of production, transmission, storage, and distribution. When used in this study, LCOH refers to the delivered cost of hydrogen.

Reliability and resiliency – Reliability refers to a system having sufficient resources to adequately meet demand while accounting for commonly-expected events (e.g. equipment failure, short-duration outages). Resilience focuses on the ability of a system to withstand/recover from high-impact, low-frequency events that are often unexpected and can result in long duration outages.[14]

Renewable energy – Renewable energy uses energy sources that are continually replenished by nature — the sun, the wind, water, the Earth's heat, and plants. Renewable energy technologies turn these fuels into usable forms of energy—most often electricity, but also heat, chemicals, or mechanical power.[15]

Renewable natural gas (RNG) – Also known as "biomethane," RNG is a combustible gas produced from the anaerobic decomposition of organic materials (i.e., biogas) that is captured and then purified to a quality suitable for injection into a gas pipeline. Major sources of biomethane include non-hazardous landfills, wastewater treatment facilities, organic waste, and animal manure. The California Public Utilities Commission (CPUC) has recognized that "Biomethane can capture methane emissions from the waste sector and be used as a direct replacement for fossil natural gas to help California reduce its GHG emissions."[16]

Total cost of ownership **(TCO)** – For the transportation sector, a metric representing a lifetime dollar ($) per mile "comprehensive analysis of vehicle ownership costs."[17] TCO in this study includes initial purchase cost, maintenance and repairs, operations, fuel cost, and taxes and subsidies (further details in Appendix 7.1.3).

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[14] CPUC Microgrids Proceeding 2.19-09-009: Resiliency Standards: Definitions and Metrics.
[15] Per NREL's Renewable Energy: An Overview report for the Department of Energy.
[16] More details on definition available at CPUC Renewable Gas.
[17] Department of Energy report on Comprehensive Total Cost of Ownership Quantification for Vehicles with Different Size Classes and Powertrains, p. xvii.

0.3. List of Figures

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1. Executive Summary

1.1. High-Level Economic Analysis & Cost Effectiveness Study Overview

Southern California Gas Company (SoCalGas) proposes to develop a hydrogen[18] pipeline system (Angeles Link) to transport clean renewable hydrogen from regional third-party production sources and storage sites to end users in Central and Southern California, including in the Los Angeles Basin (L.A. Basin). The Angeles Link pipeline system is anticipated to extend across approximately 450 miles.

Angeles Link is intended to support California's decarbonization goals[19] through the significant reduction of greenhouse gas (GHG) emissions in hard-to-electrify sectors of the economy, including dispatchable power generation, mobility,[20] and industrial sectors. Additionally, Angeles Link seeks to enhance energy system reliability and resiliency, and to enable the development of third-party long duration energy storage (LDES) resources, as California works to achieve the State's decarbonization goals.

On December 15, 2022, the California Public Utilities Commission (CPUC) approved Decision (D.) 22-12-055, authorizing SoCalGas to establish the Angeles Link Memorandum Account (ALMA) to track expenses related to conducting Phase 1 feasibility studies.[21] This High-Level Economic Analysis & Cost Effectiveness Study (hereafter referred to as the Cost Effectiveness Study) is prepared pursuant to the Phase 1 Decision (D.22-12-055, Ordering Paragraph [OP] 6 (d)). Pursuant to OP 6(d), this study considers and evaluates project alternatives, including a localized hydrogen hub and electrification, determines a methodology to measure cost effectiveness between alternatives, and evaluates the cost effectiveness of Angeles Link against alternatives. This report sets forth the scope, methodology, and results of this study.

Input and feedback from stakeholders including the Planning Advisory Group (PAG) and Community Based Organization Stakeholder Group (CBOSG) was helpful in the development of this draft Cost

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[18] As defined in the decision approving the Angeles Link Memorandum Account to Record Phase One Costs.

[19] For example, see California Air Resources Board's (CARB) 2022 Scoping Plan for Achieving Carbon Neutrality, at pp. 9-10, and Senate Bill 100 (SB 100).

[20] Governor's Executive Order N-79-20, also CARB's Advanced Clean Fleets and Truck regulations.

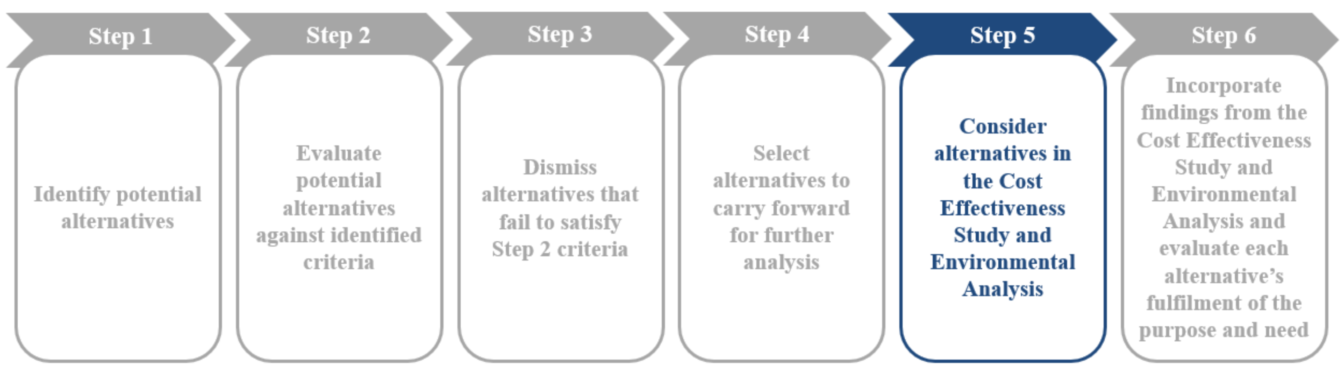
[21] Angeles Link Memorandum Account to Record Phase One Costs.

Effectiveness Study. In response to stakeholder feedback, the Cost Effectiveness Study has addressed various topics, including power transmission technologies and the cost effectiveness of hydrogen as a fuel in heavy-duty mobility applications. In addition, further details on costs and input assumptions have been added throughout this report and in the Appendix. Key feedback received related to the Cost Effectiveness Study is summarized in Section 5 below. All feedback received is included, in its original form, in the quarterly reports submitted to the CPUC and published on SoCalGas's website.[22]

1.2. Study Approach

The Cost Effectiveness Study was conducted in conjunction with the Project Options & Alternatives Study (Alternatives Study), which followed a six-step evaluation framework (see Figure 1) to identify alternatives to Angeles Link and assess them based on a range of factors. Steps 1-4 were completed in the Alternatives Study, which identified potential alternatives to Angeles Link and evaluated them against key considerations or criteria such as state policy goals, scalability, and reliability and resiliency, among others. Alternatives that met these criteria were then carried forward to Step 5 for cost effectiveness and environmental analysis. The Cost Effectiveness Study encompasses the methodology and analysis to measure the cost effectiveness of Angeles Link and alternatives for Phase 1 purposes. The Environmental Analysis, prepared as a separate Angeles Link Phase 1 report, contains a high-level analysis of potential environmental impacts of Angeles Link and its alternatives.

Figure 1: Cost Effectiveness Study's Role in Alternatives Study Evaluation Framework[23]



[22] Angeles Link: Shaping the Future with Clean Renewable Hydrogen.
[23] See Alternatives Study for additional information on the six-step evaluation framework, including the alternatives considered but dismissed for evaluation in the Cost Effectiveness Study.

The Cost Effectiveness Study evaluation is organized according to two categories of alternatives, as described in the Alternatives Study: Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives. For each category of alternatives, this study seeks to address the following questions:

Hydrogen Delivery Alternatives: *How does the cost of Angeles Link compare to the cost of alternative methods for delivering clean renewable hydrogen to end users in the region across mobility, power, and industrial sectors?*

Non-Hydrogen Alternatives: *How does the cost of clean renewable hydrogen delivered via Angeles Link compare to the cost of alternative, non-hydrogen decarbonization pathways for key use cases across mobility, power, and industrial sectors?*

Table 1 below describes the alternatives selected in the Alternatives Study for further cost analysis in this Cost Effectiveness Study.

Table 1: Portfolio of Selected Alternatives for Cost Effectiveness Evaluation

Hydrogen Delivery Alternatives	Non-Hydrogen Alternatives
• Liquid hydrogen trucking • Gaseous hydrogen trucking • Liquid hydrogen shipping • Methanol shipping • Power transmission & distribution (T&D) with in-basin hydrogen production • Localized hub	• Electrification • Carbon Capture & Sequestration (CCS)

The evaluation of Hydrogen Delivery Alternatives focused on the estimated cost of transporting clean renewable hydrogen at scale via Angeles Link (including third-party production and storage), compared to the cost of producing, storing, and transporting clean renewable hydrogen via the delivery alternatives. The cost effectiveness of Angeles Link relative to other Hydrogen Delivery Alternatives is measured using the Levelized Cost of Delivered Hydrogen (LCOH, $/kg),[24] which is an accepted energy industry metric to evaluate cost-effectiveness across various hydrogen delivery technologies.

[24] See Glossary of Terms for the definition of LCOH.

In addition to the Alternatives Study, the evaluation of Angeles Link took a number of inputs from several other Phase 1 feasibility studies including the Production Planning and Assessment (Production Study), the Demand Study, and the Routing/Configuration Analysis (Routing Analysis).[25] These studies identified eight potential operational scenarios for the Angeles Link pipeline system, referred to as "Production Scenarios."[26] The identified Production Scenarios represent various potential routes and distances connecting potential third-party production and storage areas to demand sites as well as various throughput volumes.[27]

For purposes of the Cost Effectiveness Study, a single route configuration under Production Scenario 7[28] was selected as the primary basis to compare Angeles Link to the selected Hydrogen Delivery Alternatives. Scenario 7 was selected due to its alignment with the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES)[29] hub proposal and its ability to facilitate transportation of up to 1.5 million tons per year of hydrogen to meet expected demand.

The evaluation of Non-Hydrogen Alternatives focused on the estimated cost to end users across mobility, power generation, and industrial sectors to reduce emissions using clean renewable hydrogen compared to the cost of other decarbonization pathways such as electrification or CCS. The cost effectiveness of Angeles Link relative to other Non-Hydrogen Alternatives is measured using a set of

[25] The Production Scenarios were informed by the separate Angeles Link Phase 1 Production Study and the Demand Study and are described further in the Routing Analysis and Pipeline Sizing and Design Criteria (Design Study).
[26] Refer to the Design Study for additional information.
[27] Detailed descriptions of the Production Scenarios can be found in Appendix 7.2.1. For additional details on Storage assumptions please refer to Appendix 7.5.1.
[28] The Design Study defined several preferred routes under Scenario 7. The Scenario 7 in this report corresponds to the Scenario 7 Preferred Route Configuration A, which is a single run pipeline design. See the Design Study (Table 17 and Table 19) for additional details. As discussed in the Design Study, the cost difference between the single- and mixed-run configurations ranges from 23% to 32%. The mixed-run configuration did not double the total installed pipe mileage, since only pipelines that were not part of a "looped" configuration were modeled as two-parallel lines (dual-run) to improve system resiliency, allow for continuous operation during potential disruptions, and increase storage capacity during peak usage periods. The resulting cost increase with a mix-run configuration is a relatively small fraction of the overall delivered cost.
[29] ARCHES is a statewide public-private partnership to serve as the applicant and organizer for a statewide clean hydrogen hub in California.

industry standard cost metrics customized to each end use across mobility, power generation, and industrial sectors. [30]

- The mobility use case was evaluated based on estimated Total Cost of Ownership (TCO), which reflects the total lifetime cost of owning and operating a vehicle, including purchase cost, maintenance, fuel, and other operational costs.
- The power use case was evaluated based on the estimated Levelized Cost of Electricity (LCOE), which reflects the total lifetime cost of building and operating a power generation (or storage) facility, including capital costs, financing costs, fuel, and other operating costs.
- The industrial use cases were assessed based on metrics tailored to each subsector:
    - Cogeneration: LCOE
    - Refineries: Hydrogen feedstock cost (LCOH)
    - Cement: Fuel cost equivalent ($\$/MMBtu_e$)[31]
    - Food & beverage (F&B): Fuel cost equivalent ($\$/MMBtu_e$)[32]

Further discussion on the methodology customized to each group of alternatives is included in Section 4, and additional details on techno-economic assumptions are included in the Appendix.

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[30] This study is focused on cost and does not estimate a market price for clean renewable hydrogen. For Non-Hydrogen Alternatives, the general approach used in the study was to use the LCOH of Angeles Link as a proxy for the cost of hydrogen in each application, with additional costs reflected in certain sectors (e.g., cost of last-mile distribution and dispensing for the mobility sector). Current hydrogen retail pricing in the California market is specific to hydrogen delivered via gaseous and liquid trucks in relatively small quantities for consumption primarily in the passenger FCEV market. With an anticipated increase in clean renewable hydrogen supply and connective infrastructure, it is expected that the costs of hydrogen on a delivered basis (inclusive of production, transmission, storage, and delivery, as well as additional overhead costs not considered within the scope of this study) will play a significant role as a price setting mechanism for clean renewable hydrogen.

[31] Fuel cost equivalent does not consider capital or other non-fuel operating costs and was used for the purpose of this study in sectors with lower volumes of hydrogen demand projected in the Demand Study – food & beverage and cement. The simplifying assumption is that capital cost is similar across hydrogen-fueled equipment, electrically powered equipment, and CO_2 capture equipment.

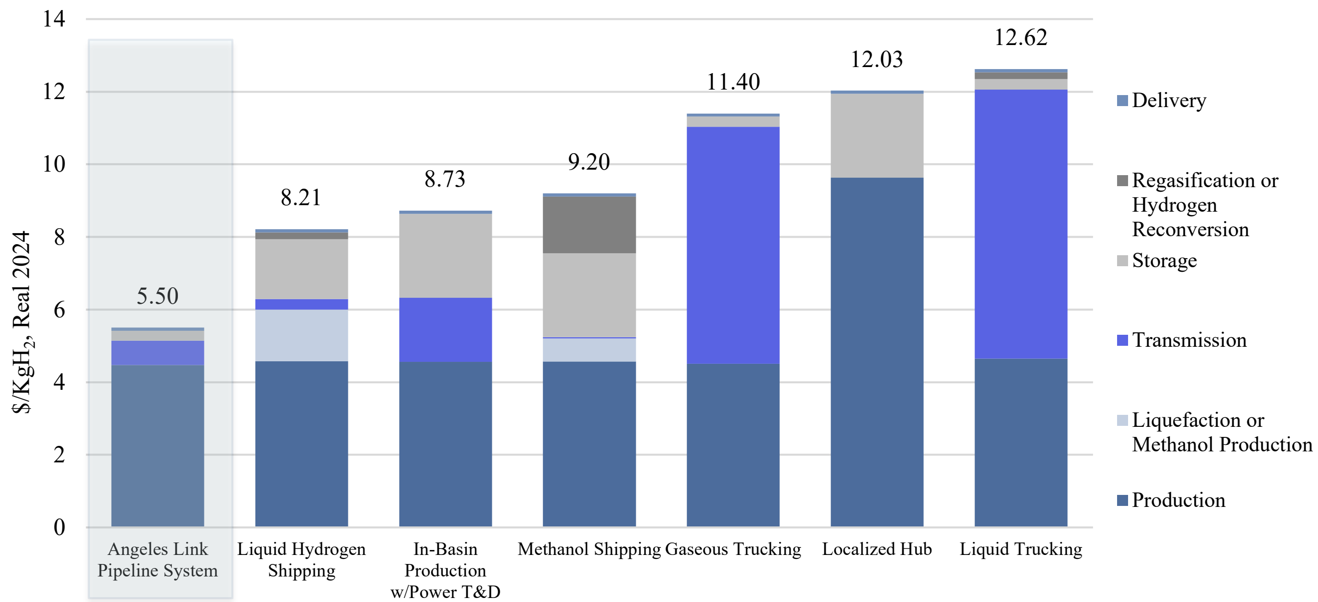
[32] Ibid.

1.3. Key Findings

1.3.1. Cost Effectiveness of Angeles Link vs. Hydrogen Delivery Alternatives

The cost effectiveness of Angeles Link Scenario 7[33] compared to the Hydrogen Delivery Alternatives is shown in Figure 2 below.

Figure 2: Cost Effectiveness of Angeles Link vs. Hydrogen Delivery Alternatives[34]



Notes: Reflects costs from Scenario 7 for 1.5 Mtpa. Production is assumed to begin in 2030 to take advantage of tax incentives, including Production Tax Credits (PTC) for hydrogen (45V)[35] and power (45Y),[36] which provide up to $3 per kgH_2 and $0.028 per kWh for ten years. Storage assumptions were based on proximity to production sites, and the geographic footprint under consideration for storage in the Production Study.[37] For Angeles Link and the trucking alternatives (gaseous and liquid), identified routes allowed for access to underground storage sites, therefore, underground storage costs were assumed. Delivery alternatives with production sites that did not overlap with the identified geological storage sites, were assumed to rely on above ground storage. These alternatives include shipping, in-basin production with T&D, and localized hub. The shipping solutions include the costs of specialized handling required to deliver methanol and liquid hydrogen. The cost for liquefaction in the liquid hydrogen trucking alternative is included as a part of transmission costs.

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[33] The Design Study defined several preferred routes under Scenario 7. Scenario 7 in this report corresponds to Scenario 7 Preferred Route Configuration A.
[34] See 7.3.1 Delivery Alternatives Assumption Tables and 7.2.2 Delivery Alternatives Descriptions for additional details.
[35] Section 45V tax credit for the production of clean hydrogen. See Election To Treat Clean Hydrogen Production Facilities as Energy Property, Section 48(a)(15).
[36] Section 45Y Clean Electricity Production Credit and Section 48E Clean Electricity Investment Credit.
[37] For additional details on the rationale for Storage assumptions from each alternative please refer to Appendix 7.5.1.

- **Angeles Link** was found to be the most cost-effective delivery method when compared to the identified Hydrogen Delivery Alternatives for Phase 1 purposes. It was also found to be the best solution to achieve the scale needed to serve projected demand at the lowest level of logistical complexity. For Angeles Link, like several Hydrogen Delivery Alternatives, the cost of clean renewable hydrogen production is the greatest contributor to total LCOH (as illustrated in Figure 2 above). The Angeles Link pipeline transport and delivery system accounts for around 12% of the total LCOH, making it the most cost-effective solution (when compared to other delivery alternatives) for meeting at-scale demand requirements as identified in the Demand Study.
- **Liquid hydrogen shipping** assumes that clean renewable hydrogen production in and around Central and Northern California regions is liquefied and shipped to L.A. ports. This alternative was found to have a gap to parity with Angeles Link of approximately $2.71/Kg$H_2$, or approximately 50% higher delivered costs than Angeles Link. The costs of liquid hydrogen shipping are driven by the cost of liquefaction near the export terminal and the need for significant in-basin above-ground hydrogen storage. Regasification at the destination port incurs additional expenses, as does the unique handling, loading, and unloading infrastructure required close to liquefaction and regasification facilities at each port.
- **In-Basin production with power transmission and distribution (T&D)** assumes renewable electricity is produced outside of the L.A. Basin and transmitted via new high voltage electric transmission lines for hydrogen production in-basin. [38] This alternative was found to have a gap to parity with Angeles Link of $3.23/kg$H_2$, or approximately 60% higher delivered cost than Angeles Link. The higher costs for this alternative are driven by both the scale of high-voltage transmission infrastructure required to deliver the electricity to produce hydrogen in the L.A. Basin and a significant need for expensive above-ground hydrogen storage in the L.A. Basin. [39]

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[38] The number of lines required depends on the power generation capacity and carrying capacity for the distance from supply to sub-station. 26.6 GW is the electricity need for the electrolysis process. Total generation also accounts for transmission losses of 1.8 GW for the scope configuration of Scenario 7 of the in-basin hydrogen production with power T&D alternative. Total installed solar capacity is estimated at 43 GW in the Production Study to account for intra-day availability. Refer to the Cost Effectiveness Study Appendix 7.2.4 and 7.3.1 for additional details.

[39] For additional information on storage assumptions, see Appendix 7.5.1.

- **Methanol shipping** was evaluated as an alternative based on the potential for clean renewable hydrogen production in and around the Central and Northern California regions that could be converted to methanol. Clean renewable methanol would then be exported, via existing methanol ship technology, and delivered into ports near the L.A. Basin, where it would be reformed (or "cracked") into hydrogen in nearby facilities. The cost of converting hydrogen to methanol, shipping methanol, and then reformulating the methanol back to hydrogen was found to have a gap to parity relative to Angeles Link of \$3.70/kgH_2, or a more than 65% higher delivered cost than Angeles Link. This finding is primarily driven by the costs associated with additional infrastructure required, including specialized handling equipment to synthesize methanol from hydrogen and crack methanol back to hydrogen and additional supporting infrastructure needed to store the hydrogen using above-ground storage in/around the L.A. Basin. Transporting methanol using ships would also require the construction of loading and unloading facilities near the ports.
- **Gaseous hydrogen trucking** with access to underground storage sites was found to be a sub-optimal delivery alternative from a cost effectiveness perspective to serve the hydrogen volumes required to meet California's decarbonization goals. Gaseous hydrogen trucking was found to have a gap to parity with the Angeles Link scenario of almost \$6.00/kgH_2, or more than double the cost of Angeles Link. This finding is driven by costs associated with the required fleet size, loading time, driving distance, and supporting infrastructure, such as compression terminals, that would need to be located near production and storage sites.
- **A localized hub** assumed local hydrogen production using in-basin renewable electricity generation. The costs of delivered hydrogen produced and delivered via the localized hub were found to be higher than those of Angeles Link by more than \$6.00/kgH_2. Higher production costs are primarily due to a higher cost of electricity because of the limited land available to develop solar generation capacity at scale within the L.A. Basin. While a localized hub may be a complementary solution to support the early stages of hydrogen throughput growth in a specific

region, it carries a higher cost and is scale-limited to meet the projected long-term demand as estimated in the Demand Study.[40]

- **Liquid hydrogen trucking** with access to underground storage sites, like gaseous hydrogen trucking, was found to be a sub-optimal delivery alternative from a cost effectiveness perspective to serve the large volumes and longer transporting distances estimated in the Demand Study. Liquid hydrogen trucking was found to have a gap to parity with Angeles Link of more than \$6.00/kgH_2. This finding is driven by costs associated with the required fleet size, loading time, driving distance, and supporting infrastructure, such as liquefaction terminals, that would need to be located near multiple production and storage sites.

1.3.2. Cost Effectiveness of Angeles Link vs. Non-Hydrogen Alternatives

As discussed in the Alternatives Study, electrification and CCS were selected as the Non-Hydrogen Alternatives for further evaluation in the Cost Effectiveness Study. The cost effectiveness of these alternatives was analyzed at a use case level in the mobility, power generation, and industrial sectors. For example, the Alternatives Study identified and selected the use cases relevant to electrification, such as comparing fuel cell electric vehicles (FCEV) and battery electric vehicles (BEV) for heavy-duty trucking. It also considered the use cases for CCS, such as comparing hydrogen power plants and natural gas power plants with CCS. Angeles Link and Non-Hydrogen Alternatives were evaluated based on a set of commonly used cost evaluation metrics in the energy industry customized to each use case to ensure a like for like evaluation of the relevant costs across the value chain for each use case. Table 2 below summarizes the alternatives, use cases, and metrics used to evaluate cost effectiveness.

[40] Due to land availability constraints in the L.A. Basin area, a localized hub can only provide 9.3% of the 1.5 Mtpa 2045 expected volumetric requirements. See Appendix 7.2.2.5 for additional details.

Table 2: Mapping of Non-Hydrogen Alternatives to Use Cases and Cost Evaluation Metrics

Sector		Angeles Link	Electrification	CCS	Cost Evaluation Metric
Mobility (long-haul, heavy-duty)		Fuel cell electric vehicles (FCEV)	Battery electric vehicles (BEV)	Not applicable to use case	TCO[3] ($/mi)
Power (clean reliable)[1]		Hydrogen power plant	Battery energy storage	Gas + CCS power plant[2]	LCOE[4] ($/MWh)
Industrial	Cogeneration	Hydrogen cogeneration facility	Not applicable to use case	Gas + CCS cogeneration facility	LCOE[4] ($/MWh)
	Refineries (process hydrogen)	Angeles Link delivery of clean renewable hydrogen	Not applicable to use case	Hydrogen abated by CCS	LCOH[5] ($/kg)
	Cement (fuel switching)	Hydrogen kiln	Electric kiln	Gas + CCS kiln	Fuel cost[6] ($/$MMBtu_e$)
	Food & Beverage (fuel switching)	Hydrogen oven/fryer	Electric oven/fryer	Not applicable to use case	Fuel cost[6] ($/$MMBtu_e$)

Note: Certain alternatives were deemed not applicable to some use cases. CCS was deemed not applicable to the mobility sector, or the food & beverage sector given the lack of point source emissions at scale. Electrification was deemed not applicable to cogeneration based on the limited available technology to provide around-the-clock electricity and heat. Electrification is also not applicable to decarbonization of hydrogen for refinery processes (other than through electrolytic hydrogen, which is the purpose of Angeles Link).

1. As established in the Alternatives Study, the power sector is divided into baseload and peaker/reliability use cases. In the baseload use case, hydrogen combustion plants supplied by Angeles Link are compared to gas plants with CCS. In the peaker/reliability use case, hydrogen combustion plants supplied by Angeles Link are compared to battery energy storage facilities.
2. "Gas + CCS" refers to a CO_2 capture technology that captures emissions from an existing facility that combusts natural gas.
3. Total Cost of Ownership (TCO) is measured on a $ per mile basis and reflects the total lifetime cost of owning and operating a vehicle, including purchase cost, maintenance, fuel, and other operational costs.
4. Levelized Cost of Electricity (LCOE) is measured on a $ per MWh basis and reflects the total lifetime cost of building and operating a power generation (or storage) facility, including upfront capital costs, financing costs, and fuel and other operating costs.
5. Levelized Cost of Delivered Hydrogen (LCOH) is measured on a $ per kg basis and reflects the cost of delivered clean renewable hydrogen from Angeles Link (or the cost of adding CCS to unabated hydrogen from existing natural gas-fueled supply).
6. Cement and food & beverage use cases were analyzed based on delivered fuel cost only, with hydrogen (as feedstock) and electricity costs converted to an equivalent $ per MMBtu basis using standard energy value conversions.

1.3.2.1. Cost Effectiveness of Angeles Link vs. Electrification

The cost effectiveness results for Angeles Link and electrification alternatives across mobility, power, and industrial use cases are shown Figure 3 below. The ranges (shown in Figure 3 in gray bars) reflect a degree of uncertainty in the economic analysis for Phase 1 purposes given the high-level assumptions incorporated, including for capital, fuel, and electricity costs, and other operational considerations. The assumptions underlying these ranges are discussed further in Section 4.2.1, with additional detail provided in Appendix 7.3.2.

Electrification refers to a combination of system level[41] transformation and use case level[42] technology changes, including the grid infrastructure required to support growing electric load. As discussed in the Alternatives Study, the cost effectiveness assessment for electrification was conducted on a use case level for the purposes of this Phase 1 Cost Effectiveness Study. System-level electrification was not assessed as it would necessitate a complex power flow modeling analysis to determine the necessary infrastructure capacity expansion, system interconnections, and system operational requirements to meet North American Electric Reliability Corporation (NERC) reliability standards under loss of load scenarios. An overview of key considerations for the viability of system-level electrification, including the potential cost of supply using wind, solar, and battery storage alone, can be found in the Alternatives Study.[43]

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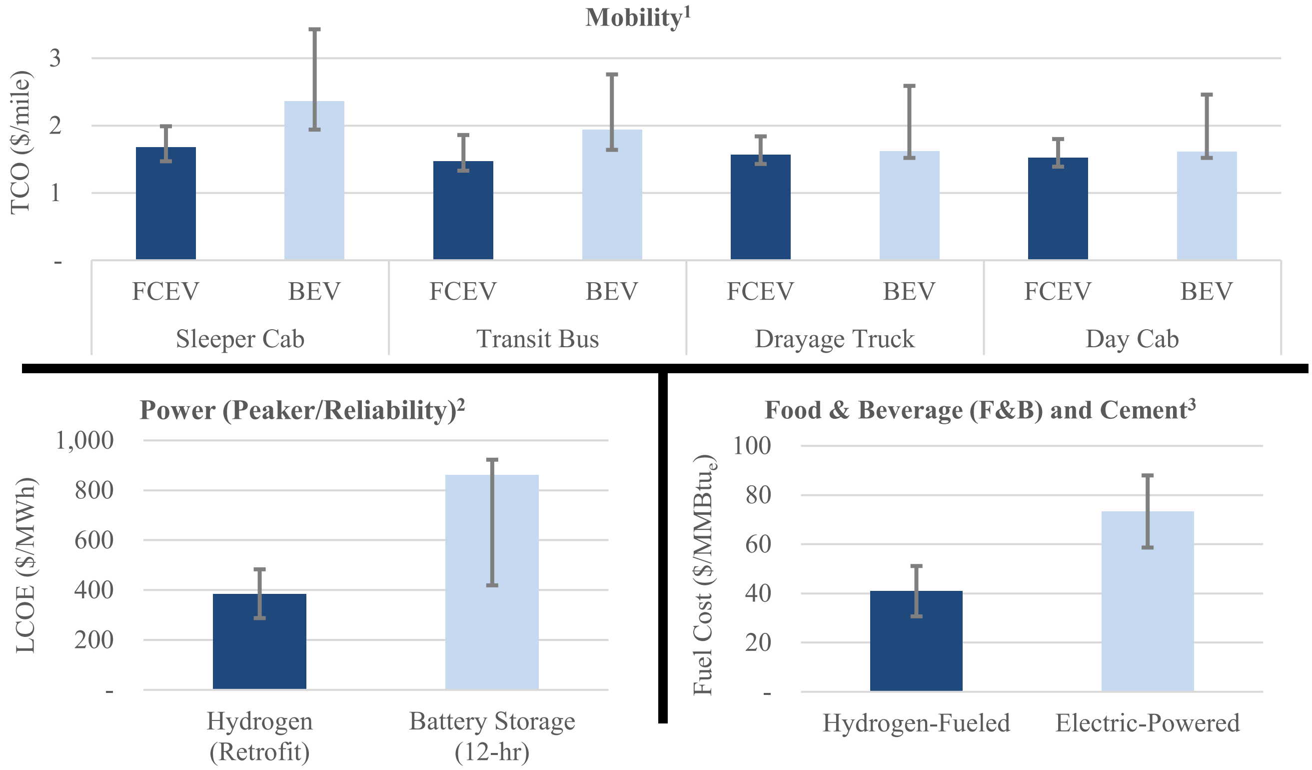
[41] System level electrification includes the incremental electricity generation, storage, and supporting upstream grid infrastructure requirements to meet wide-scale end use electrification needs.
[42] Use-case level electrification implies replacing technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically powered equivalents, such as electric vehicles or heat pumps.
[43] See Appendix 7.3.2. of the Alternatives Study.

Figure 3: Cost Effectiveness of Angeles Link vs. Electrification Across Use Cases



1. Reflects the total lifetime cost of owning and operating a vehicle, including purchase cost, maintenance, fuel, and other operational costs. Refer to Section 4.2.1.1 for additional details of the cost analysis and Appendix 7.3.2.1 for detailed assumptions.
2. Reflects the total lifetime cost of building and operating a power generation (or storage) facility, including upfront capital costs, financing costs, and fuel and other operating costs. Refer to Section 4.2.1.2 for additional details of the cost analysis and Appendix 7.3.2.2 for detailed assumptions.
3. Reflects only the cost of delivered fuel or electricity to cement and food & beverage facilities. Refer to Section 4.2.1.3 for additional details of the cost analysis and Appendix 7.3.2.4 for detailed assumptions.

In the **mobility** sector, FCEVs (served by clean renewable hydrogen from Angeles Link) have been shown to be more cost effective compared to BEVs (the electrification alternative) for long-haul use cases. This is especially relevant for applications such as Class 8 sleeper cabs and transit buses that require en-route refueling.[44] FCEVs were also found to be a strong competitor for drayage trucks and

[44] En-route refueling (or charging) involves refueling a vehicle at a retail refueling station located along highways or other convenient locations on major roads or highways. Depot charging involves refueling (or charging) a vehicle, often overnight, in a warehouse or a fleet location where the vehicles are housed after a driver's shift. Source: [ICCT.]

day cabs, especially when considering the possible range of charging costs. Additionally, factors such as operating patterns based on the vehicle class and fleet operator business models are likely to influence the adoption of these technologies, alongside economic considerations.

In the **power** sector, gas-fueled generation facilities retrofitted to run on clean renewable hydrogen (supplied by Angeles Link) were found to be cost effective relative to longer duration lithium-ion battery storage facilities (the electrification alternative).[45] This is driven by the high estimated capital costs of lithium-ion when sized to this longer-duration capability. Fundamentally, there are few electrification solutions that can provide a direct comparison to Angeles Link for the Central and Southern California power system, where Angeles Link can support both clean firm generation and LDES. The challenges of system-level electrification analysis and the selection of 12-hour lithium-ion as the comparison to Angeles Link in the power sector are discussed in the Alternatives Study.[46]

In the **cement** and **food & beverage** (F&B) sectors, hydrogen-fueled kilns, ovens, and fryers (supplied by Angeles Link) were found to be cost effective relative to electric kilns, ovens, and fryers (the electrification alternative). This is driven by high industrial electricity tariffs in California.

1.3.2.2. Cost Effectiveness of Angeles Link vs. CCS

The cost effectiveness results for Angeles Link and CCS alternatives across power and industrial use cases is shown in Figure 4. The ranges (indicated in gray bars) reflect a degree of uncertainty in the economic analysis given the high-level assumptions incorporated for Phase 1 purposes, including for capital, fuel and electricity costs, and other operational considerations. The assumptions underlying these ranges are discussed further in Section 4.2.2, with additional detail provided in Appendix 7.3.2.

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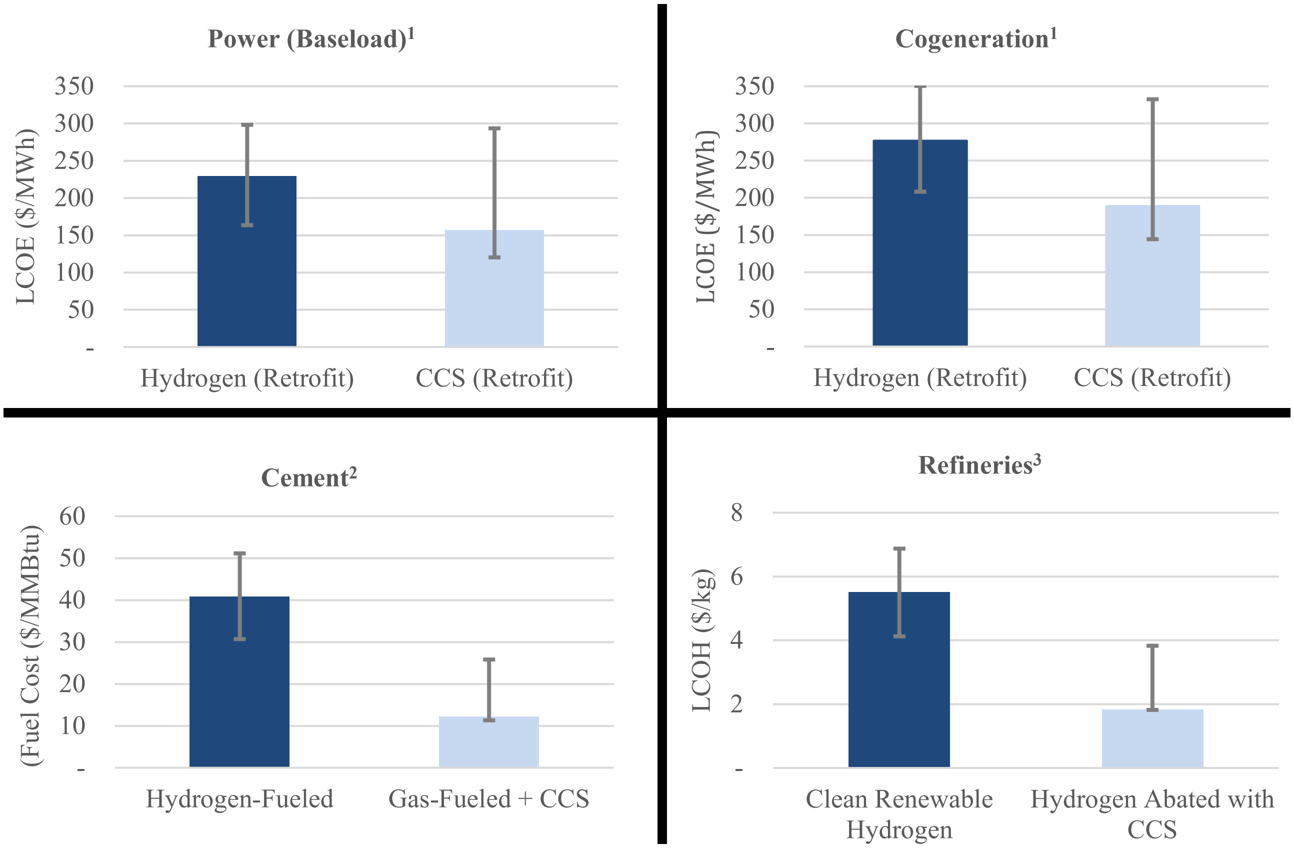
[45] Modeled as three, four-hour units to provide up to 12 hours of discharge duration capability to test the cost of lithium-ion in longer-duration use cases which hydrogen capable of serving.
[46] See Appendix 7.3.2 and 7.3.3 of the Alternatives Study.

Figure 4: Cost Effectiveness of Angeles Link vs. CCS Across Use Cases



1. Reflects the total lifetime cost of building and operating a power generation (or cogeneration) facility, including upfront capital costs, financing costs, and fuel and other operating costs. Refer to Section 4.2.1.1 for additional details of the cost analysis and Appendix 7.3.2 for detailed assumptions.
2. Reflects only the cost of delivered fuel or electricity to cement facilities, in addition to the cost of CO_2 transport and sequestration tariffs. Refer to Section 4.2.2.2 for additional details of the cost analysis and Appendix 7.3.2.5 for detailed assumptions.
3. Reflects the cost of delivered clean renewable hydrogen from Angeles Link or the cost of hydrogen abated with CCS. Refer to Section 4.2.2.3 for additional details of the cost analysis and Appendix 7.3.2.6 for detailed assumptions.

In the **power and cogeneration** sectors, natural gas facilities retrofitted to run on clean renewable hydrogen (supplied by Angeles Link) fall within the range of cost effectiveness relative to natural gas facilities retrofitted with carbon capture equipment (the CCS alternative). While CCS retrofits were found to be more cost effective than clean renewable hydrogen turbines due to the low relative cost of natural gas, CCS adoption will be heavily dependent on site level and regional factors, including geospatial constraints, remaining facility life, and access to CO_2 transport and sequestration infrastructure near point sources, all of which could impact technical feasibility and cost.

In the **cement** sector, hydrogen-fueled kilns (supplied by Angeles Link) were not found to reach cost parity with natural gas-fueled kilns retrofitted with carbon capture equipment (the CCS alternative). This cost gap is primarily driven by the higher cost of clean renewable hydrogen (as a feedstock) relative to natural gas. Given that cost of CCS is likely to be affected by CO_2 transport distances and the accessibility of sequestration locations, there is uncertainty about the ultimate cost of CO_2 transport to end users until system development progresses. CCS adoption is therefore expected to be feasible for cement facilities in proximity to other industrial clusters where there is available CO_2 transport and sequestration infrastructure, and subject to enabling state policy. Senate Bill (SB) 596 requires the cement sector in California to reach net-zero GHG emissions by 2045,[47] and both CCS and hydrogen can be a key enabler to help advance SB 596 goals.

In the **refinery** sector, clean renewable hydrogen supplied by Angeles Link for refinery process use (i.e., hydrotreating) was not found to reach the same level of cost parity with hydrogen abated by carbon capture (the CCS alternative). This cost gap is driven by the higher cost of clean renewable hydrogen (as a feedstock) relative to the cost natural gas with CO_2 capture, transport, and sequestration. Despite the cost effectiveness of CCS for this use case, CCS may face geospatial limitations or may not be viable due to the age of the facility. CCS retrofits for refinery process use versus the use of clean renewable hydrogen will also be influenced by state policy, the availability of CO_2 transport and sequestration infrastructure, and the decarbonization strategies specific to each refinery.

1.3.3. Conclusion

The California Air Resources Board's (CARB) 2022 Scoping Plan identified clean renewable hydrogen as a critical component to achieving California's decarbonization objectives, particularly in hard-to-electrify sectors of the economy. [48] Angeles Link is intended to support the CARB's Scoping Plan and California's decarbonization goals through the delivery of clean renewable hydrogen to serve customers

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[47] Net-Zero Emissions Strategy for the Cement Sector | California Air Resources Board.
[48] See California Air Resources Board's (CARB) 2022 Scoping Plan for Achieving Carbon Neutrality, at pp. 9-10, and Senate Bill 100 (SB 100).

in hard-to-electrify sectors. This study found that for Phase 1 purposes, a pipeline system like Angeles Link offers a cost-effective solution to transport clean renewable hydrogen to serve Central and Southern California, including the L.A. Basin, at scale. Clean renewable hydrogen delivered by Angeles Link was also found to be cost effective for Phase 1 purposes relative to electrification and CCS as alternative decarbonization pathways for certain hard-to-electrify industrial sectors, dispatchable power generation, and heavy-duty transportation. While this analysis was required by the CPUC to compare electrification as an "alternative" to Angeles Link, the CARB Scoping Plan supports the finding that a portfolio of pathways, including electrification and clean renewable hydrogen, will be needed to drive the State's decarbonization goals.

2. Study Background

2.1 Purpose and Objectives of the Study

This study is being prepared pursuant to CPUC Decision (D.22-12-055, Ordering Paragraph [OP] 6(d)). In accordance with OP6(d), this study evaluates the cost effectiveness of Angeles Link against alternatives for Phase 1 purposes and determines a methodology to measure cost effectiveness between alternatives.

The Cost Effectiveness Study considered the alternatives identified in the Alternatives Study (see the Alternatives Study for additional information), developed a methodology to measure the cost-effectiveness between Angeles Link and the alternatives, and performed an analysis of the cost-effectiveness of the alternatives based on that methodology. Specifically, the Cost Effectiveness Study uses a methodology to measure cost effectiveness that includes gathering cost estimates, performing an economic analysis to determine the potential levelized cost of delivered clean renewable hydrogen (LCOH) to end users, and comparing the cost effectiveness of Angeles Link to the identified project alternatives.

The evaluation focused on Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives (as discussed in the Alternatives Study).

This study provides a high-level analysis for Phase 1 purposes of the economics and cost-effectiveness of Angeles Link and selected alternatives and does not evaluate future tariffs or the impact on ratepayers associated with Angeles Link's construction and operation and maintenance costs. That analysis is expected to occur in future phases as Angeles Link is further refined.

2.2 Dependencies with Other Studies

The Cost Effectiveness Study is dependent on several other studies conducted as part of Phase 1 of Angeles Link.

- The Alternatives Study identified and selected the Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives to be analyzed in this study and summarized key findings across economic and non-economic factors.

- The Production Study informed locations of the potential third-party production and potential third-party storage assets, and related costs used to estimate cost effectiveness in the Cost Effectiveness Study.
- The Design Study provided information on the location, sizing, and cost of new clean renewable hydrogen pipeline that was used to estimate cost effectiveness in the Cost Effectiveness Study.
- The Water Resources Evaluation informed the costs related to water supplies for potential third-party clean renewable hydrogen production to estimate cost effectiveness in the Cost Effectiveness Study.

3. Overview of Study Methodology

The Cost Effectiveness Study followed three main stages. The methodology is discussed in further detail in Sections 1.2 and 2.2 for both Hydrogen Delivery Alternatives and Non-Hydrogen Alternatives. Additional detailed assumptions and technical information are also available in the Appendix.

Stage 1: Compile Inputs and Align Scope Configurations on a "Like-for-Like" Basis for Cost Analysis

For Hydrogen Delivery Alternatives, a core principle of the analysis was the consistent application of key project parameters, including a common hydrogen production configuration, end-user delivery system, system throughput expectations (hydrogen volumes), demand profile, and potential storage needs. Many of these elements were defined in the Alternatives Study based on inputs from the Production Study and the Design Study and compiled for cost modeling purposes in this study.

As defined in Table 3, scope configurations for each delivery alternative were customized based on their inherent technical and operational requirements and constraints. Trucking alternatives, which allow for more flexibility, were assumed to connect the same hydrogen production and geological storage locations to demand along similar corridors as those identified for Angeles Link in the Production Study. However, for several other alternatives, solar generation, hydrogen production, and storage sites were adjusted to reduce logistical complexity, while still achieving scale, supporting system reliability and resiliency to the extent possible. For liquid hydrogen and methanol shipping, it was assumed that solar generation and hydrogen production would occur on a more centralized basis, closer to ports in Northern California so that hydrogen could then be shipped to ports in L.A. Basin. As geological storage sites were not identified in Northern California, it was assumed that shipping delivery alternatives would rely on above ground storage. The localized hub alternative was assumed to source power from small-scale solar sources in-basin. The in-basin hydrogen production with power T&D alternative assumed the same power generation locations and capacity as Angeles Link, and the transport of electrons via 500 kV transmission lines generally following similar corridors as Angeles Link.[49] For both localized hub and in-basin hydrogen production with T&D, where hydrogen production occurs in L.A. Basin, above ground storage was assumed, as there were no geological storage sites identified within the L.A. Basin in the Production Study.

For purposes of the cost analysis, Non-Hydrogen Alternatives were defined at a use case level across the mobility, power generation, and industrial sectors as discussed in the executive summary (see Alternatives Study for additional information).

Additional cost and operational input assumptions not available through the Angeles Link Phase 1 feasibility studies were compiled as needed, from public and proprietary sources reflecting market and industry dynamics (e.g., cost assumptions for alternatives, plant size, new build vs. retrofit, capacity factor, etc.).

A summary of each alternative's definition and configuration is included in Section 4, with additional details on techno-economic assumptions in the Appendix.

Stage 2: Establish Methodology for Cost-Effectiveness Analysis

Once scope configurations for the alternatives were defined, a methodology for evaluating cost effectiveness was customized to each group of alternatives (Hydrogen Delivery and Non-Hydrogen).

- The Angeles Link Pipeline System and Hydrogen Delivery Alternatives were assessed based on the Levelized Cost of Delivered Hydrogen (LCOH), which reflects the total lifetime capital and operating costs of all the assets along the hydrogen production, transportation, storage, and delivery value chain.[50]

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[49] A 500kV AC transmission system was selected in order to meet the capacity requirements for the Delivery Alternative. The 500kV system is largely compatible with the CAISO grid, which is mostly AC. As discussed in Appendix 7.3.1.2.4, the effective load carrying capacity for a typical 500kV AC transmission system does not exceed 3GW, rapidly declining with the transmitting distance. Hence, supporting 26.6 GW of electricity load requirement (in addition to the 1.8 GW of transmission load losses) for hydrogen production would require multiple transmission lines consisting of 10 double circuit and 1 single circuit transmission system (for a total of 21 circuits) across a 400 mile transmission corridor (accounting for a total of 2,500 miles of transmission). Refer to Appendix 7.2.2 and 7.3.1 for additional details.

[50] The Angeles Link Pipeline System is proposed to facilitate the transportation of clean renewable hydrogen from multiple regional third-party production source and storage sites to various delivery points and end users in Central and Southern California, including the L.A. Basin.

- Angeles Link Pipeline System and Non-Hydrogen Alternatives were evaluated based on metrics customized to each use case and commonly used in the industry:
  - The mobility use case was evaluated based on estimated Total Cost of Ownership (TCO), which reflects the total lifetime cost of owning and operating a vehicle, including purchase cost, maintenance, fuel, and other operational costs.
  - The power use case was evaluated based on the estimated Levelized Cost of Electricity (LCOE), which reflects the total lifetime cost of building and operating a power generation (or storage) facility, including capital costs, financing costs, fuel, and other operating costs.
  - The industrial use cases were assessed based on metrics tailored to each subsector:
    - Cogeneration: LCOE
    - Refineries: Hydrogen feedstock cost (LCOH)
    - Cement: Fuel cost equivalent ($MMBtu_e$)[51]
    - Food & beverage: Fuel cost equivalent ($MMBtu_e$)[52]

Further discussion on the methodology tailored to each group of alternatives is included in Sections 4.1 and 4.2, with additional details on techno-economic assumptions in the Appendix of this report.

Stage 3: Evaluate Cost Effectiveness

Once the methodology was established, the cost-effectiveness analysis was performed for each group of alternatives. The results of the analysis are discussed in Sections 4.1 and 4.2, with additional details on the evaluation methodology, assumptions and associated sources in the Appendix.

[51] Fuel cost equivalent does not consider capital or other non-fuel operating costs and was used for the purpose of this study in sectors with lower volumes of hydrogen demand projected in the Demand Study – food & beverage and cement. The simplifying assumption is that capital cost is similar across hydrogen-fueled equipment, electrically powered equipment, and CO_2 capture equipment.
[52] Ibid.

4. Key Findings

4.1. Cost Effectiveness of Angeles Link & Hydrogen Delivery Alternatives

This section summarizes the key findings of the analysis comparing the cost effectiveness of the Angeles Link Pipeline System to the identified Hydrogen Delivery Alternatives, as well as the cost effectiveness across the eight Production Scenarios[53] evaluated for the Angeles Link Pipeline System. Each analysis is described below:

- **Angeles Link Pipeline System vs. Hydrogen Delivery Alternatives** compares the cost-effectiveness of Angeles Link and Hydrogen Delivery Alternatives[54] based on a single common set of assumptions[55] for throughput (volume), production areas, and associated supporting infrastructure, including storage,[56] based on Scenario 7.
- **Angeles Link Pipeline System Comparison by Scenario** compares the high-level economics across the eight Production Scenarios defined for Angeles Link in the Design Study, reflecting a range of assumptions for throughput (volume), production areas, and storage types.

The cost effectiveness of the Angeles Link Pipeline System and Hydrogen Delivery Alternatives is evaluated using the Levelized Cost of Delivered Hydrogen (LCOH) in dollars per kilogram ($/kg) of hydrogen delivered. This metric, which accounts for the lifetime cost of all the assets in the hydrogen production, transportation, storage, and delivery value chain is commonly used in the industry to capture the unit costs of hydrogen.[57]

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[53] For additional information on the scenarios, see Appendix 7.2.1.
[54] The Hydrogen Delivery Alternatives were defined, evaluated, and shortlisted in the Alternatives Study. Refer to the Alternatives Study for additional information.
[55] In this section, Angeles Link and Hydrogen Delivery Alternatives are evaluated based on Scenario 7, which is defined in the Design Study. Results of the cost analysis for all Angeles Link scenarios vs. all Hydrogen Delivery Alternatives are provided in Appendix 7.4.1.
[56] For additional information on storage assumptions, see Appendix 7.5.1.
[57] For Hydrogen Delivery Alternatives, LCOH also includes any necessary value chain infrastructure, such as loading, trucking, shipping, liquefaction, compression, power transmission, and other specialized handling like methanol production and reconversion (reforming). The LCOH framework and additional details are provided in Appendix 7.1.1.

The cost assessments incorporated key input assumptions from other Phase 1 studies, third-party reports,[58] relevant pipeline system costs from SoCalGas, and third-party cost models.

4.1.1. Angeles Link Pipeline System vs. Hydrogen Delivery Alternatives

The **Angeles Link Pipeline System vs. Hydrogen Delivery Alternatives** analysis compares LCOH across Angeles Link and the six Hydrogen Delivery Alternatives:

1. Liquid hydrogen trucking
2. Gaseous hydrogen trucking
3. Liquid hydrogen shipping
4. Methanol shipping
5. In-basin production with power T&D
6. Localized hub

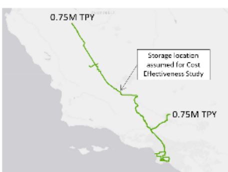
The scope configuration for Angeles Link and each Hydrogen Delivery Alternative was defined to reflect specific throughput volumes, production areas, and corresponding hydrogen storage[59] as defined for Scenario 7 of Angeles Link in the Design Study and summarized below.[60]

- **Throughput volumes**: 1.5 million tonnes per annum (mtpa).
- **Third-party production centers**: Include production in and around San Joaquin Valley (SJV) and Lancaster. For certain Hydrogen Delivery Alternatives, Northern California or in-basin production were also considered.
- **Third-party storage types:** Include underground storage such as depleted oil and gas reservoirs, as well as above-ground storage.[61]

[58] Including National Petroleum Council. (2024). Harnessing Hydrogen: A Key Element of the U.S. Energy Future and Chen, F., Ma, Z., Nasrabadi, H., Chen, B., Mehana, M. Z. S., & Van Wijk, J. (2024). Capacity Assessment and Cost Analysis of Geologic Storage of Hydrogen: A Case Study in Intermountain-West Region USA. Los Alamos National Laboratory and Texas A&M University.
[59] For additional information on storage assumptions, see Appendix 7.5.1.
[60] The comparison was performed for all eight scenarios; see Appendix 7.4.1 for comparison across scenarios and delivery alternatives.
[61] For additional information on storage assumptions see, Appendix 7.5.1. As discussed in the Production Study, storage can also be provided in the pipeline system through linepack and other methods. Linepack for storage was not included in the Design Study, so it was left out of this analysis.

Scenario 7 was selected as the baseline for the detailed comparison in this chapter due to its alignment with ARCHES and its ability to facilitate transportation of up to 1.5 million tons per year of hydrogen to meet expected demand as defined in the Demand study. [62] Table 3 below summarizes the Scenario 7 configuration applied across the Angeles Link Pipeline System and the Hydrogen Delivery Alternatives.

Table 3: Angeles Link Pipeline System vs. Hydrogen Delivery Alternatives Configuration[63]

Angeles Link Scenario	Map	Delivery Methods	Production (mtpa)				Storage	
			SJV	Lancaster	Central/ Northern California	In-Basin	Depleted Oil Fields	Above-Ground
7		Angeles Link Pipeline System	0.75	0.75			✓	
		Gaseous Hydrogen Trucking	0.75	0.75			✓	
		Liquid Hydrogen Trucking	0.75	0.75			✓	
		Liquid Hydrogen Shipping			1.5			✓
		Methanol Shipping			1.5			✓
		In-Basin Production				1.5		✓
		Localized Hub				0.14		✓

Notes: The closer the production center, the less pipeline mileage required, reducing transmission costs. Some scenarios combine different sites. The fewer sites required, the more efficiencies achieved with less pipeline mileage and thus lower transmission costs. Above-ground storage assumes higher relative costs, and among underground storage options, salt caverns are more costly than depleted oil fields.[64] Scenario 7 does not include any underground geological salt caverns due to a lack of potential resource availability along the route.

For each alternative, scope configurations were customized based on their inherent technical and operational requirements and constraints. For example, the shipping alternatives assumed production occurs closer to potential export ports, and included additional costs associated with the development of connective infrastructure to transport hydrogen from production areas to ports for shipping.

Figure 5 provides a summary of the results of the LCOH analysis[65] comparing Angeles Link to the selected Hydrogen Delivery Alternatives. The analysis includes all costs from hydrogen production to delivery. The analysis found that Angeles Link is the most cost-effective solution for Phase 1 purposes

[62] The Design Study defined several preferred routes under Scenario 7. Scenario 7 in this report corresponds to Scenario 7 Preferred Route Configuration A.

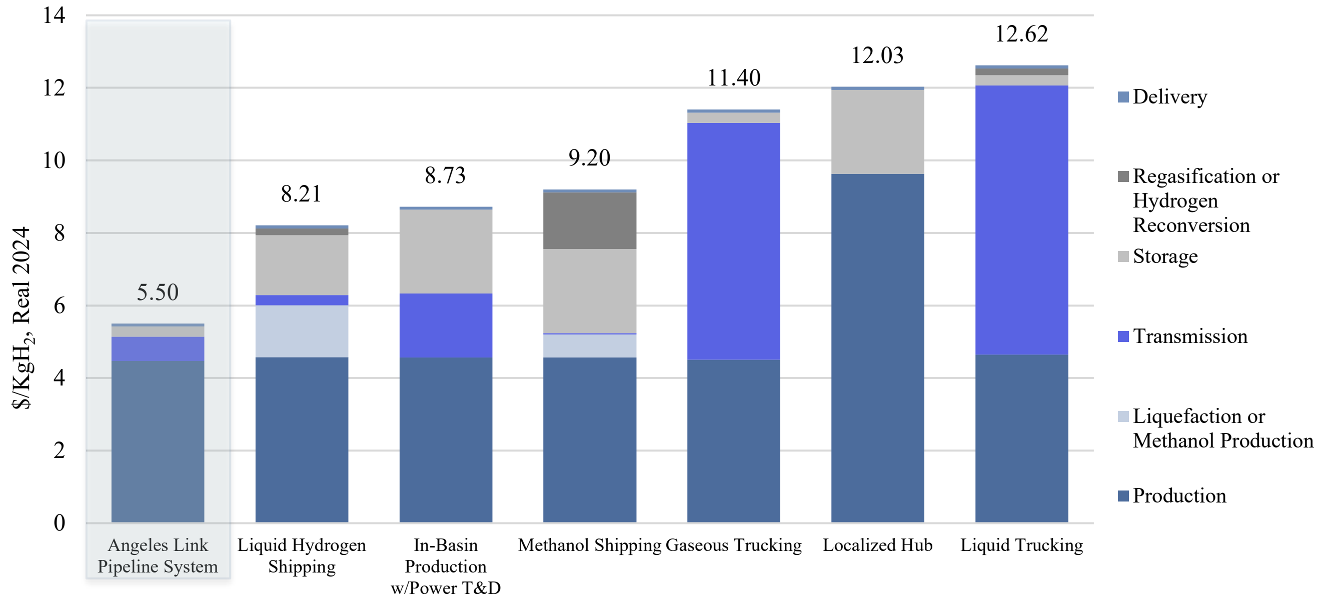
[63] For Phase 1 cost effectiveness evaluation purposes, production sites were assumed to be close enough to transmission or distribution origination points to not require supply side laterals or interconnections for Angeles Link and Hydrogen Delivery Alternatives.

[64] For additional information on storage assumptions, see Appendix 7.5.1.

[65] A full matrix of LCOH for all scenarios, comparing different throughput volumes, production locations, and storage options, can be found in Appendix 7.4.1.

with an estimated LCOH of $5.50/kgH$_2$. The liquid hydrogen trucking alternative was found to have the largest gap to cost parity (over $6.00/kgH$_2$) when compared to Angeles Link, with an estimated LCOH of $12.62/kgH$_2$.

Figure 5: Cost Effectiveness of Angeles Link vs. Hydrogen Delivery Alternatives[66]



Notes: Reflects costs from Scenario 7 for 1.5 Mtpa. Production is assumed to begin in 2030 to take advantage of tax incentives, including Production Tax Credits (PTC) for hydrogen (45V) [67] and power (45Y), [68] which provide up to $3 per kgH$_2$ and $0.028 per kWh for ten years. Storage assumptions were based on proximity to production sites, and the geographic footprint under consideration for storage in the Production Study.[69] For Angeles Link and the trucking alternatives (gaseous and liquid), identified routes allowed for access to underground storage sites, therefore, underground storage costs were assumed. Delivery alternatives with production sites that did not overlap with the identified geological storage sites, were assumed to rely on above ground storage. These alternatives include shipping, in-basin production with T&D, and localized hub. The shipping solutions include the costs of specialized handling required to deliver methanol and liquid hydrogen. The cost for liquefaction in the liquid hydrogen trucking alternative is included as a part of transmission costs.

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[66] See 7.3.1 Delivery Alternatives Assumption Tables and 7.2.2 Delivery Alternatives Descriptions for additional details.
[67] Section 45V tax credit for the production of clean hydrogen. See Election To Treat Clean Hydrogen Production Facilities as Energy Property, Section 48(a)(15).
[68] Section 45Y Clean Electricity Production Credit and Section 48E Clean Electricity Investment Credit.
[69] For additional details on the rationale for Storage assumptions from each alternative please refer to Appendix 7.5.1.

Table 4 below details the costs for each segment of the value chain for Angeles Link and each Hydrogen Delivery Alternative.

Table 4: Angeles Link and Hydrogen Delivery Alternatives Cost by Value Chain Component

Cost Component ($/Kg$H_2$)	Angeles Link Pipeline System	Liquid Hydrogen Shipping	In-Basin Production w/Power T&D	Methanol Shipping	Gaseous Hydrogen Trucking	Localized Hub	Liquid Hydrogen Trucking
Delivery[70]	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Regasification or Hydrogen Reconversion[71]	N/A	$0.18	N/A	$1.56	N/A	N/A	$0.18
Storage[72]	$0.28	$1.65	$2.31	$2.31	$0.28	$2.31	$0.29
Transmission	$0.67	$0.29	$1.76	$0.04	$6.53	N/A	$7.41
Liquefaction or Methanol Production	N/A	$1.42	N/A	$0.64	N/A	N/A	Included in transmission
Production[73]	$4.47	$4.59	$4.58	$4.57	$4.51	$9.64	$4.66
Total LCOH	**$5.50**	**$8.21**	**$8.73**	**$9.20**	**$11.40**	**$12.03**	**$12.62**

Notes: Reflects costs from Scenario 7 for 1.5 Mtpa. Production is assumed to begin in 2030 to take advantage of tax incentives, including production tax credits (PTC) for hydrogen (45V) [74] and power (45Y), [75] which provide up to $3 per kg$H_2$ and $0.028 per kWh for ten years. Due to the hydrogen production locations identified for some alternatives, the Angeles Link Pipeline System and the trucking alternatives (gaseous and liquid) assume underground storage, while other alternatives assume above-ground storage.[76] The shipping solutions include the costs of specialized handling required to deliver methanol and liquid hydrogen. The cost for liquefaction in the liquid hydrogen trucking alternative is included as a part of transmission costs.

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[70] As discussed in the Design Study (see Figure 7 Route A Map), the pipelines within Central Zone to the Ports of Los Angeles and Long Beach (Point 4 to 5) were calculated to require 80 miles for the single-run configuration. To adhere to the principle of comparing delivery alternatives on a like-for-like basis, all delivery alternatives assumed an approximately 80-mile delivery system. For additional details, refer to Appendix 7.3.1.5.

[71] Regasification or hydrogen reconversion are part of the transportation process for liquid hydrogen shipping, methanol shipping and liquid hydrogen trucking. These processes are not used for the other Hydrogen Delivery Alternatives

[72] Underground storage was assumed for Angeles Link and the trucking alternatives. All other Hydrogen Delivery Alternatives were assumed to have above-ground storage. For additional information on storage assumptions see Appendix 7.5.1.

[73] While production costs were the same, each delivery alternative had different losses (per Appendix 7.3.1.7) along the value chain, which means the LCOH would show slight variations.

[74] Section 45V tax credit for the production of clean hydrogen. See Election To Treat Clean Hydrogen Production Facilities as Energy Property, Section 48(a)(15).

[75] Section 45Y Clean Electricity Production Credit and Section 48E Clean Electricity Investment Credit.

[76] For additional details on the rationale for Storage assumptions from each alternative please refer to Appendix 7.5.1. the storage solution selected reflects the best available for a like for like comparison.

Figure 5 and Table 4 show the following key results:

- **The Angeles Link Pipeline System** was found to be the most cost-effective solution for delivering hydrogen at scale across Central and Southern California, including the L.A. Basin. The cost of clean renewable hydrogen production represents over 80% of the total LCOH of \$5.50/kgH_2. In comparison, the cost of the pipeline transport and delivery system represents approximately 12% of the total LCOH, and the cost of storage represents 5% of the total LCOH.
- **Liquid hydrogen shipping** assumes that clean renewable hydrogen production in and around Central and Northern California regions is liquefied and shipped to the ports in the L.A. Basin. This alternative was found to have an LCOH of \$8.21/kgH_2, or approximately 50% higher than Angeles Link. The costs of liquid hydrogen shipping are driven by the cost of liquefaction near the export terminal and the need for significant in-basin above-ground hydrogen storage, which combined reflect 37% of the total LCOH. Regasification at the destination port would incur additional expenses, as would the unique handling, loading, and unloading infrastructure required close to liquefaction and regasification facilities at each port.
- **In-basin production with power T&D** was found to have an LCOH of \$8.73/kgH_2, as it would require extensive and costly infrastructure compared to Angeles Link Pipeline System, since new long-distance electric transmission lines[77] would be needed to bring the power to in-basin hydrogen production centers and would require in-basin above-ground storage near the in-basin production facilities. Costs associated with long-distance transmission coupled with in-basin above-ground storage[78] represent approximately 47% of the total LCOH, and result in a significant increase in the cost of delivered hydrogen.
- **Methanol shipping** assumed clean renewable hydrogen production in and around the Central and Northern California regions with conversion to methanol. Clean renewable methanol would then be exported via existing methanol shipping technology and reformed (or “cracked”) into

[77]The number of lines required depends on the power generation capacity and carrying capacity for the distance from supply to sub-station. 26.6 GW is the electricity need for the electrolysis process. Total generation also accounts for transmission losses of 1.8 GW for the scope configuration of Scenario 7 of the in-basin hydrogen production with power T&D alternative. Total installed solar capacity is estimated at 43 GW in the Production Study to account for intra-day availability. See Appendix 7.2.2 and 7.3.1 for additional details.

[78] More details on above-ground storage costs can be found in Appendix 7.5.17.2.

hydrogen upon delivery to ports in the L.A. Basin. The cost of this complex value chain was estimated at $9.20/kgH_2$, or 65% higher than Angeles Link. This is primarily driven by the costs associated with additional infrastructure requirements, including specialized handling equipment to synthesize methanol from hydrogen and crack methanol back to hydrogen, in addition to above-ground hydrogen storage in and around the L.A. Basin. Transporting methanol using ships would also require the construction of loading and unloading facilities near the ports. These additional steps in the value chain reflect roughly 49% of the total LCOH.

- **Gaseous hydrogen trucking** with access to underground storage sites was found to be sub-optimal from a cost effectiveness perspective to serve the volumes required to meet California's decarbonization goals. Gaseous hydrogen trucking was found to have a delivered cost of hydrogen of $11.40/kg, or more than double the cost of Angeles Link. This is driven by costs associated with the required fleet size, loading time, driving distance, and supporting infrastructure such as compression terminals needed in multiple hydrogen production and storage sites. These additional steps in the value chain result in transmission costs of $6.53/kgH_2$, or roughly 57% of the total LCOH.
- **The localized hub**, which assumed local hydrogen production using in-basin renewable electricity generation, was found to have the highest hydrogen production costs at $9.63/kgH_2$. Higher hydrogen production costs are primarily driven by the higher cost of electricity due to limited land available within the L.A. Basin for the development of solar generation capacity at scale. The localized hub would also rely on above-ground hydrogen storage in-basin. As a result of these challenges, the LCOH across the entire value chain for the localized hub was estimated at $12.03/kgH_2$.
- **Liquid hydrogen trucking** with access to underground storage sites, like gaseous hydrogen trucking, was found to be sub-optimal from a cost effectiveness perspective to serve the large volumes and long distances required. Liquid hydrogen trucking was found to have a delivered LCOH of $12.62/kgH_2$, or more than double the cost of Angeles Link. This is driven by costs associated with the required fleet size, loading time, driving distance, and supporting infrastructure such as liquefaction terminals needed at multiple production and storage sites. As a

result of these additional steps in the value chain, liquid hydrogen trucking transmission costs reflect 59% of the total LCOH.

4.1.2. Angeles Link Comparison by Scenario

Eight Production Scenarios were modeled for Angeles Link (as defined in the Design Study) reflecting various throughput volumes, production areas, and hydrogen storage types:

- **Throughput volumes**: Range from 0.5 to 1.5 million tonnes per annum (mtpa).
- **Third-party production centers**: Include production in and around SJV, Lancaster, and Blythe areas.
- **Third-party storage types:** Include underground storage such as depleted oil and gas reservoirs and salt caverns, as well as above-ground storage.[79]

The scenario configurations for the Angeles Link Pipeline System are presented in Table 5 below.[80]

[79]For additional information on storage assumptions, see Appendix 7.5.1. As discussed in the Production Study, storage can also be provided in the pipeline system through linepack and other methods. Linepack for storage was not included in the Design Study, so it was left out of this analysis.
[80] For additional details, see Table 15 in the Appendix.

Table 5: Scenario Description for Angeles Link Pipeline System[81]

Scenario	Throughput Volumes	Hydrogen Production (mtpa)			Angeles Link Pipeline System Miles[82]	Hydrogen Storage	
		SJV	Lancaster	Blythe		Depleted Oil/Gas Reservoirs	Salt Caverns
1	0.5 Mtpa	0.5			355	✓	
2			0.5		314	✓	
3				0.5	303[83]		✓
4	1.0 Mtpa	0.5	0.5		392	✓	
5			0.5	0.5	537[83]	✓	✓
6		0.5		0.5	578[83]	✓	✓
7	1.5 Mtpa	0.75	0.75		390	✓	
8		0.5	0.5	0.5	616[83]	✓	✓

The variability in LCOH across the scenarios is driven by differences in throughput volumes and transport distance (mileage) between production areas, hypothetical storage sites,[84] and end users. The result of the cost effectiveness analysis for each scenario are summarized in Figure 6 below. The LCOH is represented in columns to illustrate the value chain costs to produce, store, transport, and deliver hydrogen.

The results show the most cost-effective configurations have the largest throughput volumes and the shortest distances between third-party production and storage locations and end users. Figure 6 below illustrates the range of costs based on each scenario.

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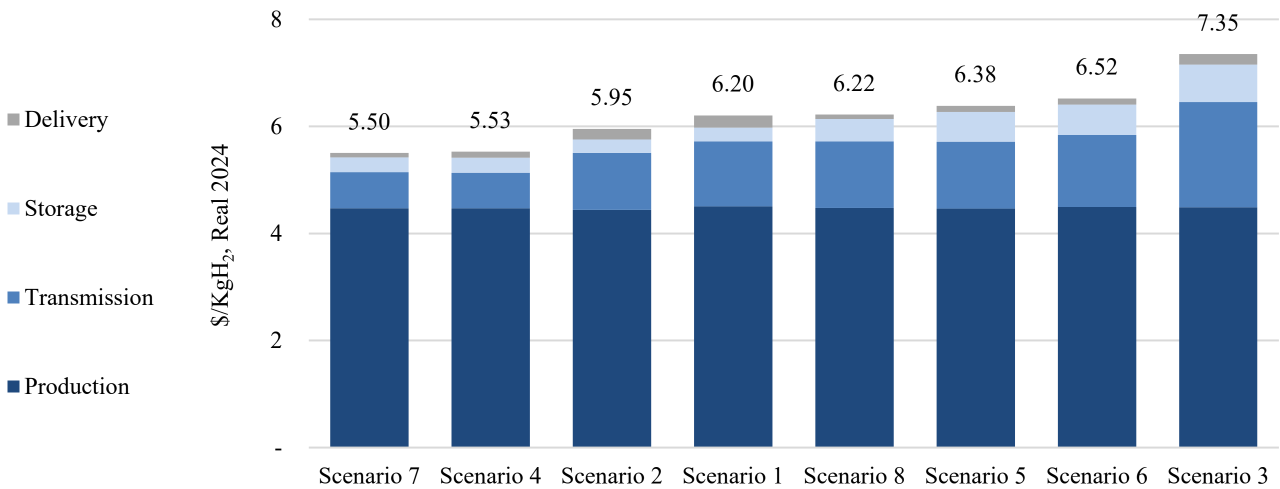
[81] Per the Production Scenarios defined in the Pipeline Sizing and Design Studies.

[82] As discussed in the Design Study (see Figure 7 Route A Map), the pipelines within the Central Zone to the Ports of Los Angeles and Long Beach (Point 4 to 5) were calculated to require 80 miles for the single-run configuration. To adhere to the principle of comparing delivery alternatives on a like-for-like basis, all delivery alternatives assumed an approximately 80-mile delivery system. For additional details, refer to Appendix 7.3.1.5.

[83] Given salt cavern storage, the transmission pipeline requires an additional 100 miles, which were included in the cost assumptions for the scenarios that have production at Blythe as the salt cavern storage access needs are near Phoenix, Arizona.

[84] For additional information on storage assumptions see Appendix 7.5.1.

Figure 6: Cost Effectiveness of Angeles Link Pipeline System by Scenario[85]



[85] Additional information on the scenarios can be found in the Appendix 7.2 of this study. Refer to the Design Study for a detailed assessment of all scenarios. To adhere to the principle of comparing delivery alternatives on a like-for-like basis, all delivery alternatives assumed an approximately 80-mile delivery system. For additional details, refer to Appendix 7.3.1.5.

Table 6 below details the LCOH for each segment of the value chain across the scenarios.

Table 6: Cost Effectiveness by Angeles Link Scenario[86]

Component	Scenario 7	Scenario 4	Scenario 2	Scenario 1	Scenario 8	Scenario 5	Scenario 6	Scenario 3
Throughput (Mtpa)	1.5	1.0	0.5	0.5	1.5	1.0	1.0	0.5
# of System Miles[87]	390	392	314	355	616[62]	537[62]	578[62]	303[88]
Storage Type	Depleted Oil/Gas Res.	Depleted Oil/Gas Res.	Depleted Oil/Gas Res.	Depleted Oil/Gas Res.	Depleted Oil/Gas Res./Salt Caverns	Depleted Oil/Gas Res./Salt Caverns	Depleted Oil/Gas Res./Salt Caverns	Salt Caverns
Delivery[89] ($/Kg$H_2$)	$0.08	$0.11	$0.19	$0.23	$0.08	$0.11	$0.11	$0.20
Third-Party Storage ($/Kg$H_2$)	$0.28	$0.28	$0.25	$0.26	$0.42	$0.56	$0.56	$0.70
Transmission ($/Kg$H_2$)	$0.67	$0.66	$1.06	$1.21	$1.24	$1.25	$1.34	$1.97
Third-Party Production[90] ($/Kg$H_2$)	$4.47	$4.47	$4.44	$4.51	$4.48	$4.46	$4.50	$4.49
Total Costs ($/Kg$H_2$)	**$5.50**	**$5.53**	**$5.95**	**$6.20**	**$6.22**	**$6.38**	**$6.52**	**$7.35**

The scenario analysis indicated the following general conclusions:

- Production costs remain similar across all scenarios, while transmission costs vary due to differences in pipeline mileage and throughput volumes.
- Scenarios with the highest throughput of 1.5 Mtpa were found to have lower costs as the scale helps bring down the cost on a per unit basis. Additionally, pipeline transportation costs are lowest in scenarios where third-party production locations require minimal pipeline mileage due to their proximity to the L.A. Basin. Furthermore, the availability of underground storage sites, especially depleted oil and gas reservoirs that may be closer to production sites, would support lower delivery costs compared to other scenarios.

[86] Additional information on the scenarios can be found in the Appendix 7.2 of this study. Refer to the Design Study for a detailed assessment of all scenarios.
[87] Includes ~80-miles for delivery infrastructure.
[88] To integrate inter-state salt cavern storage (in Arizona), an additional 100 miles of pipeline routing would be needed and was considered as part of the cost evaluation for the appropriate scenario under evaluation.
[89] To adhere to the principle of comparing delivery alternatives on a like-for-like basis, all delivery alternatives assumed an approximately 80-mile delivery system. For additional details, refer to Appendix 7.3.1.5.
[90] Assumes 45V Production Tax Credit (PTC) for ten years.

- Scenario 7, at \$5.50 per kgH_2, was found to be the most cost-effective scenario. This is driven by the scale of throughput, the proximity of potential third-party production areas (such as SJV and Lancaster) to the L.A. Basin, and the underground storage resources that may be developed over time as demand for clean renewable hydrogen scales over the planning horizon as discussed in the Demand Study.
- Scenario 3, at \$7.35 per kgH_2, was found to have the greatest gap to parity with Scenario 7. This is driven by longer pipeline lengths (mileage) to connect a lower throughput of hydrogen from potential third-party production locations further from the L.A. Basin, (such as Blythe) and the integration of inter-state geologic storage resources (such as salt caverns in Arizona).

4.2. Cost Effectiveness of Angeles Link & Non-Hydrogen Alternatives

This section describes the findings from the cost-effectiveness analysis of Angeles Link vs. Non-Hydrogen Alternatives (electrification and CCS) across a range of specific use cases in mobility, power, and industrial sectors. Each subsection provides an overview of the use cases and methodology, results of the cost analysis, a discussion of the sensitivity ranges applied to key assumptions, and a summary of non-economic considerations identified in the Alternatives Study.

4.2.1. Cost Effectiveness of Angeles Link vs. Electrification

Details of the four use case analyses are below, comparing Angeles Link to electrification across the following applications:

- **Mobility**: FCEV vs. BEV for long-haul, heavy-duty applications.
- **Power**: Hydrogen-fueled combustion plant vs. 12-hour battery energy storage facility for peaking and reliability needs.
- **Food & beverage (F&B)**: Hydrogen-fueled ovens/fryers vs. electric ovens/fryers.
- **Cement**: Hydrogen-fueled kilns vs. electric kilns.

4.2.1.1. Mobility

The mobility end use evaluation compared hydrogen FCEVs (supplied by Angeles Link) vs. BEVs (the electrification alternative). Specifically, both FCEVs and BEVs are evaluated for the four primary long-haul, heavy-duty applications described in the Demand Study: sleeper cab, transit bus, drayage truck, and day cab. These applications, as detailed in the Demand Study, have the greatest hydrogen adoption potential due to their operational requirements (including high payloads, long routes, and high duty cycles). To determine cost effectiveness in the mobility sector, a TCO analysis was conducted to capture the lifetime ownership and operational costs across the modeled vehicle classes.

Table 7: Configurations and Cost Metrics for Mobility

Mobility Use Case	Alternative	Technology Application	Cost Metric
• Sleeper Cab • Transit Bus • Drayage Truck • Day Cab	**Angeles Link**	Fuel Cell Electric Vehicle	Total Cost of Ownership (TCO) ($/mile)
	Electrification	Battery Electric Vehicle	

The TCO analysis was derived from third-party models,[91] which include inputs from a combination of market intelligence and national lab research (including Argonne National Lab, the National Renewable Energy Laboratory (NREL) and other relevant industry related sources). The TCO includes the typical costs associated with purchasing, fueling/charging, and maintaining vehicles, in addition to other operational factors, including labor, dwell and payload costs.[92] The operations component of the TCO includes the following key drivers:

- Labor cost represents the cost of the driver's time during a shift.
- Dwell cost reflects the opportunity cost associated with queueing and refueling/charging times.
- Payload costs reflect the indirect cost from reduced payload capacity to accommodate the weight of batteries or fuel cell stacks relative to diesel engines.

Sensitivity analysis across the FCEV and BEV purchase cost, fuel/charging cost, and operational patterns influence the overall TCO. The vehicles' refueling patterns, changes in incentives, and fuel cost uncertainty could have a significant impact on a vehicle's overall cost of ownership. The implications of these sensitivities are discussed below. Additional details of the TCO modeling assumptions including sensitivities can be found in Appendix 7.3.2.1.

4.2.1.1.1. Cost Analysis Results

As shown in Figure 7, the findings indicate FCEVs are cost-effective relative to BEVs for the two vehicle classes (sleeper cabs and transit buses) with longer range requirements and en-route refueling needs. The TCO analysis shows directional cost-parity (where the cost of ownership over the economic life of a vehicle is almost the same) for vehicle classes such as drayage trucks and day cabs. This cost

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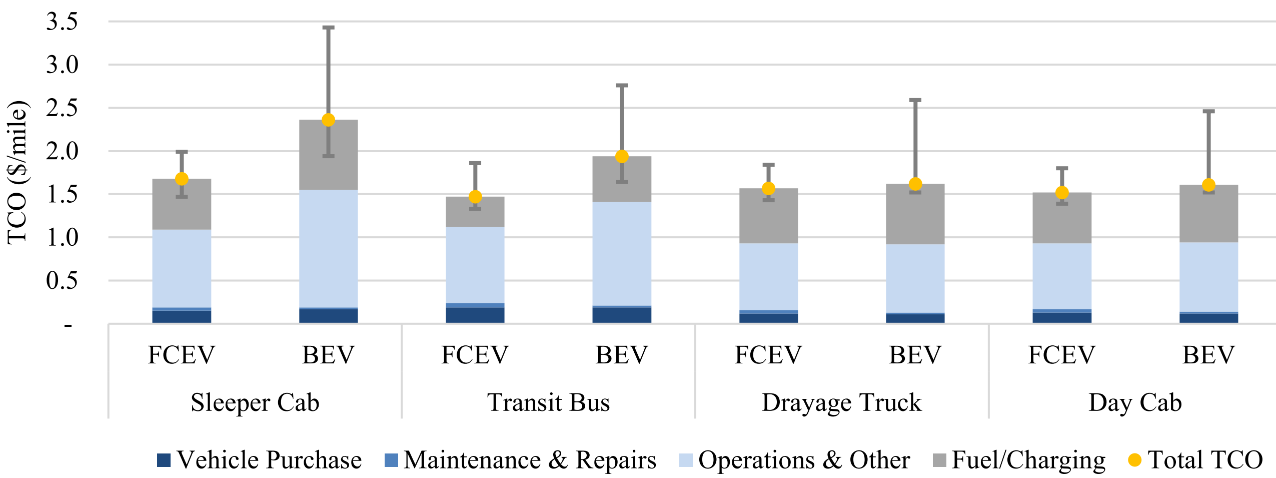
[91] Third-party TCO models, with input assumptions detailed in Appendix 7.1.3.
[92] The TCO for this cost effectiveness analysis excludes insurance, registration, tolls and parking.

equivalence is due to these applications typically traveling shorter distances in a duty cycle and taking advantage of depot refueling, which can offset refueling expenses over the course of a vehicle's economic life. Additional findings from the TCO analysis across the four modeled vehicle classes are discussed below.

Figure 7: Cost Effectiveness: Mobility (2030)[93]



Sleeper cab and transit bus: These two vehicle classes were found to show the greatest cost advantage for FCEV over BEV. The TCO for sleeper cab FCEV ranges from $1.5 - $2.0 per mile vs. $1.9 - $3.4 per mile for BEV. The TCO for transit bus FCEV ranges from $1.3 - $1.9 per mile vs. $1.6 - $2.8 per mile for BEV. The lower cost for FCEVs is primarily driven by lower operational costs due to faster refueling (reflected in lower dwell costs) compared to BEVs. Sleeper cabs and transit buses often refuel while on the road during a driver's shift, and the study assumes BEVs will face high charging costs at retail stations based on commercial models in the market today and the high electricity tariffs in California.[94]

Drayage truck and day cab: These vehicle classes offer directional cost parity between FCEV and BEV technology, although BEV models are not at cost parity at the higher end of the sensitivity range

[93] Assumes that both FCEVs and BEVs travel 100,000 miles a year and have an economic life of 10-12 years. The range in gray depicts the range of estimation and sensitivity analysis in the TCO across key assumptions. Detailed assumptions are provided in Appendix 7.3.2.17.3.1.7.
[94] Southern California Edison (SCE) Schedule TOU-D-PRIME. The retail rate used in this analysis was a weighted average of SCE bundled time-of-use rates.

given the large range of charging costs observed in the market. The TCO for drayage truck FCEV ranges from \$1.4 - \$1.8 per mile vs. \$1.5 - \$2.6 per mile for BEV. The TCO for day cab FCEV ranges from \$1.4 - \$1.8 per mile vs. \$1.5 - \$2.5 per mile for BEV. The Demand Study describes the duty cycle of drayage trucks, which are primarily involved in port operations, operating around the clock across multiple shifts, and refuelling at a central depot. Day cabs typically operate in 8-hour duty cycles, do not run around the clock, and refuel at a central depot. This depot refueling pattern results in parity in operational and fuel costs between FCEV and BEV, as longer BEV charging times are not considered to make an economic impact, and depot charging is assumed to come at lower cost than en-route retail charging.[95]

4.2.1.1.2. Key Sensitivities: Operational Costs and Fuel/Charging Costs

Two of the most critical drivers of the TCO analysis are the operational costs and the fuel/charging costs. These assumptions and the analyzed sensitivities are discussed in greater detail below.

Operational Costs

Operational costs include labor, payload, and dwell time.[96] Expenses associated with dwell time (dwell cost), is the cost component that most influences the relative parity of FCEVs and BEVs, driven by the longer charging time of BEVs. The study treats dwell time costs differently based on the distinction between en-route or depot refueling/charging patterns. Sleeper cab and transit bus applications are assumed to use primarily en-route refueling, and the study incorporates dwell cost into the TCO for this pattern to reflect the economic impact of refueling/charging time during the duty cycle. Alternatively, drayage truck and day cab applications are assumed to use primarily depot refueling, and the study assumes zero dwell cost in the TCO for this pattern as the time spent refueling/charging is primarily post-duty cycle. Sensitivities were used to test different percentage mixes of the two refueling/charging patterns, as well as potential improvements in BEV charging times, with the impact on dwell times and overall operations costs across sensitivities shown in the Figure 8 below.

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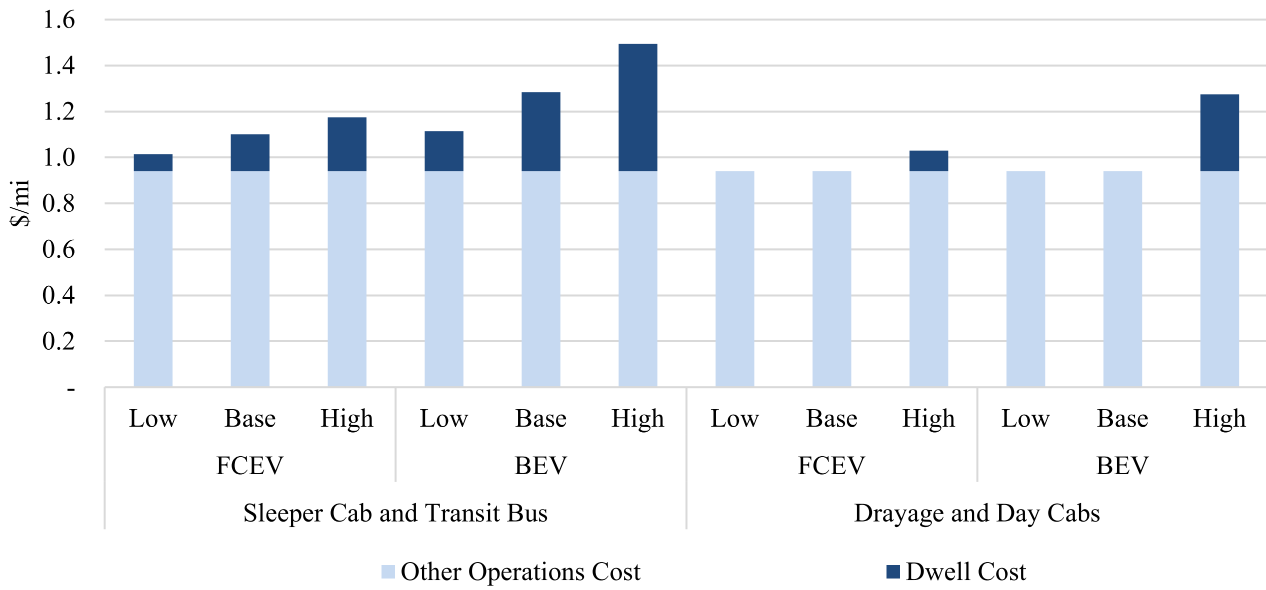
[95] En-route charging involves refueling a vehicle at a retail refueling station located along highways or other convenient locations on major roads or highways. Depot charging involves refueling a vehicle, often overnight, in a warehouse or a fleet location where the vehicles are housed after a driver's shift. Based on the assumption that on-the-road retail charging stations charge a higher markup to recover a return on investment for charging infrastructure investment. Source: ICCT.
[96] Dwell time is the time a vehicle stops for refueling or charging at a fueling or electric charging station.

Figure 8: Dwell Cost Proportion of Total Operations Costs Across Sensitivities[97]



Fuel/Charging Costs

Fuel/charging cost is a key component driving the TCO and is primarily influenced by feedstock costs for hydrogen for the FCEVs and electric charging costs for the BEVs. The hydrogen fuel costs reflect the estimated LCOH for Angeles Link. This cost includes delivery of the fuel to a central point in the L.A. Basin and operation of an approximately 80-mile delivery pipeline system. An additional cost for last-mile distribution and dispensing has been included to account for the expenses associated with delivering the product to the refueling station and the cost of the refueling equipment. The costs of hydrogen fuel also include the assumption that station owners will have access to Low Carbon Fuel Standard (LCFS)[98] credits, which can be passed on to customers.

Electric charging costs include current electricity tariffs available to commercial scale electric charging stations, estimated costs of the station (including the charging equipment and associated power infrastructure), the cost of renewable electricity certificates (RECs) to offset the carbon footprint of grid electricity, and a retail markup[99] to align with prices observed in the California market. This retail

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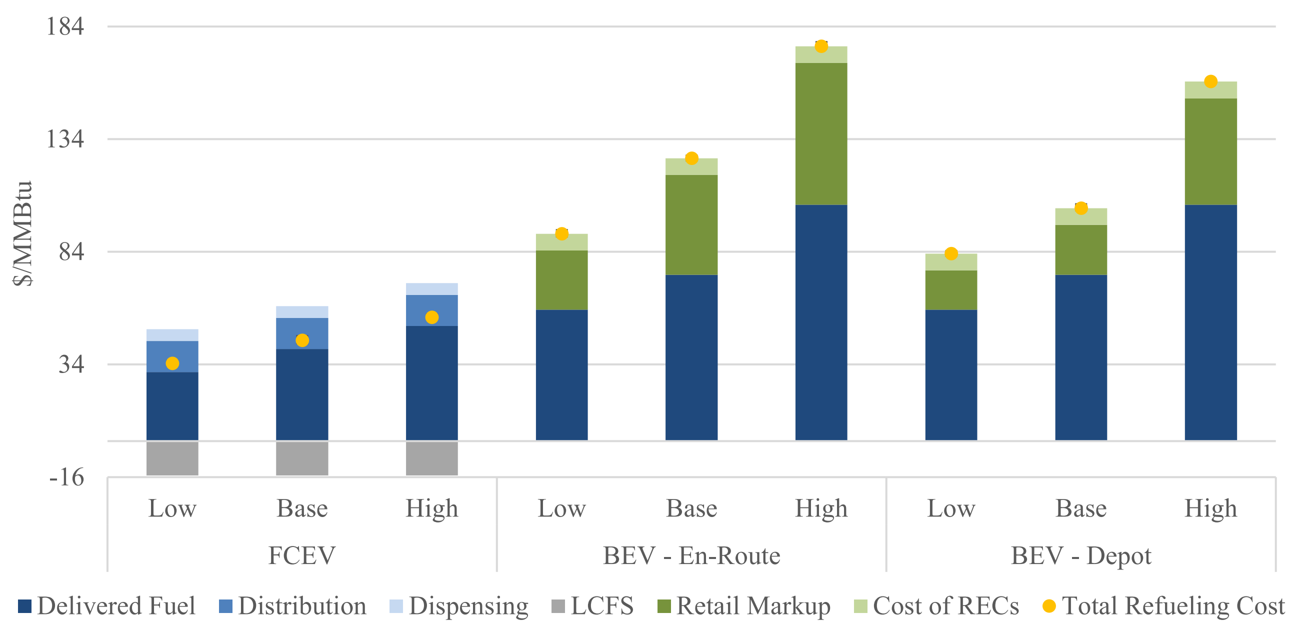
[97] Refer to Appendix 7.3.2.1 for the underlying data assumptions reflected in the Low, Base and High sensitivity cases
[98] Low Carbon Fuel Standard | California Air Resources Board.
[99] About 30% for depot and 60% for en-route refueling patterns, with additional considerations taken to incorporate any incentives, such as LCFS. Additional details provided in Appendix 7.3.2.1.

markup was adjusted depending on the en-route vs. depot charging pattern to reflect the assumption that en-route charging typically comes with higher retail prices, while depot or centralized charging can provide lower prices based on customer-owned infrastructure or third-party infrastructure with lower required returns. Sensitivities were performed to capture the various levels of uncertainty in fuel/charging costs in general, as well as to specifically examine different percentage combinations of en-route and depot charging patterns. Figure 9 below displays a breakdown of the components and variations in fuel/charging costs across different sensitivities.

Figure 9: Fuel/Charging Cost Breakdown by Technology and Refueling Pattern[100]



Note: Hydrogen in $/kg and electricity in $/kWh were converted to a common unit ($/MMBtu) from an energy equivalency basis for purposes of a direct comparison above. The LCFS for BEVs are included in the retail markup cost component of the fuel cost.

4.2.1.1.3. Non-Economic Considerations

Based on the analysis of the four vehicle classes above, it was determined that both FCEVs and BEVs fall within cost parity across the specified sensitivity ranges. However, when it comes to long-haul and

[100] Refer to Appendix 7.3.2.1 for the underlying data assumptions reflected in the Low, Base and High sensitivity cases.

heavy-payload use cases, FCEVs have an advantage due to technical considerations. As discussed in the Alternatives Study, FCEVs offer a natural advantage as fleet owners and drivers face minimal changes in daily operations relative to current technology. For BEVs, drivers and fleet operators may need to adapt to new business models, new charging patterns, longer charging times and potentially increased investment in additional vehicles to maintain current business patterns and accommodate decreased payload.

4.2.1.2. Power

In the power sector, hydrogen combustion power plants (supplied by Angeles Link) and longer duration 12-hour battery storage facilities (the electrification alternative for the purpose of this study) were analyzed for a use case where power plants or storage facilities provide extended reliability services to the grid during periods of peak demand. As discussed in the Alternatives Study, Angeles Link is assessed based on a retrofitted hydrogen-fueled combustion plant, while electrification is assessed based on a series of three sequenced 4-hour lithium-ion battery units to enable 12 hours of total duration capability to serve system reliability needs beyond what typical 4-hour duration batteries can provide as shown in Table 8 below.

Lithium-ion batteries are commercially available based on 4- to 8-hour durations and are not typically classified as a long-duration solution; however, the goal of this analysis was to select a technology with reliable cost data and technology maturity that could reasonably illustrate the strengths and weaknesses of an electrification alternative for the power use case. The rationale for choosing a 12-hour battery to provide grid reliability services is detailed in the Appendix section of the Alternatives Study. The assumption of a retrofitted combustion plant is based on the rationale that power plant owners would replace existing gas turbines with hydrogen-capable turbines, in line with Los Angeles Department of Water and Power's (LADWP) decision to retrofit its Scattergood facility.[101]

An LCOE analysis was conducted to compare these alternatives to capture the lifetime capital and operating costs per unit of electricity produced. The LCOE represents the present value of the total capital, operational, and financing costs associated with installing and operating a new or retrofitted

[101] Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project | Los Angeles Department of Water and Power (ladwp.com).

generation or storage asset over its economic lifespan. LCOE is widely used by governments, utilities, and independent power producers as it provides a common metric to assess the economic competitiveness of different generation technologies and can also be adapted to assess the economics of storage technologies.

Table 8: Configurations and Cost Metrics for Power

Power Use Case	Alternative	Technology Application	Cost Metric
Low Capacity Factor / Reliability Units	Angeles Link	Hydrogen Turbine (retrofit)[102]	Levelized Cost of Electricity (LCOE) ($/MWh)
	Electrification	12-hr Battery Storage	

Sensitivity ranges in the LCOE analysis reflect the range of uncertainty across the upfront capital and operating costs, fuel/charging costs, and capacity factors which influence the total generation output of the facility. The implications of these sensitivities are discussed in Key Sensitivities (see Section 4.2.1.2.2). Additional details of the LCOE modeling assumptions can be found in Appendix 7.3.2.2.

4.2.1.2.1. Cost Analysis Results

The results from the LCOE analysis show that a retrofitted hydrogen turbine that operates at a lower capacity factor would be more cost-effective when compared to a 12-hour battery storage resource (the rationale for selecting a 12-hour battery for providing long-duration storage requirements is detailed in the Alternatives Study). The high upfront cost of building a battery storage facility designed for a 12-hour duration outweighs the higher hydrogen fuel cost (reflected by the estimated delivered LCOH of Angeles Link) for operating a retrofitted turbine. Detailed assumptions and ranges of capital expenditures, operational costs, applicable incentives, and performance metrics are provided in the Appendix 7.3.2.2. The component breakdown of the LCOE is shown below in Figure 10.

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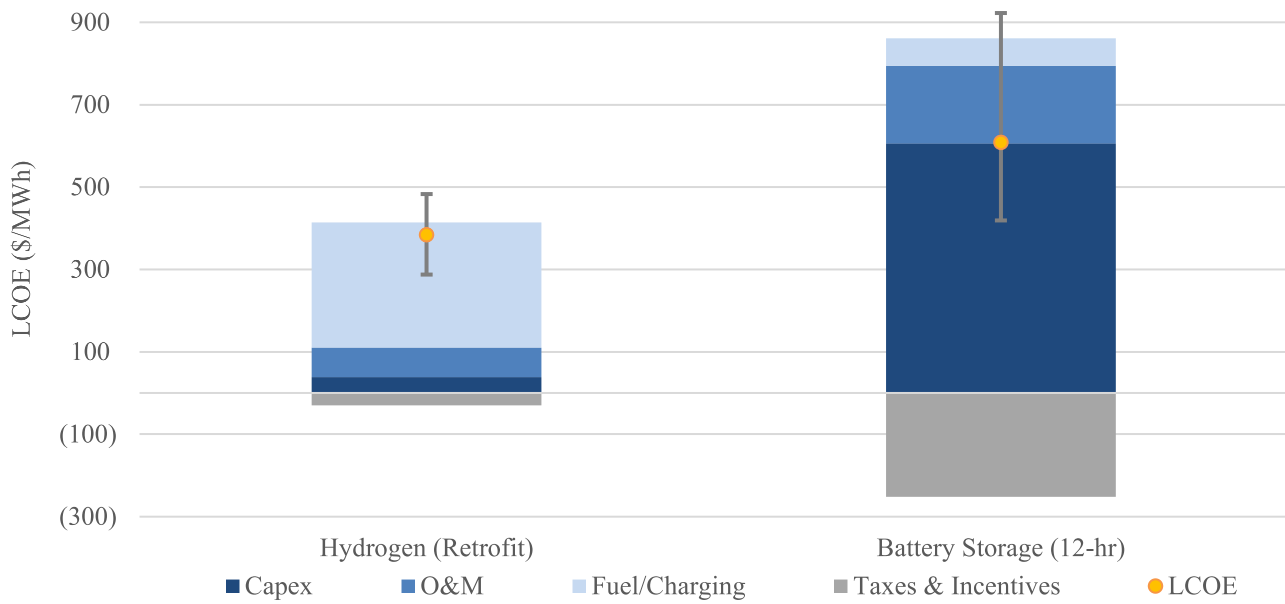
[102] Retrofitted hydrogen turbines involve replacing existing natural gas turbines with hydrogen-capable turbines. This is further detailed in the Alternatives Study.

Figure 10: Cost Effectiveness: Power (Hydrogen and Battery Storage) (2030)



Note: For taxes and incentives, hydrogen power plant retrofits are assumed to be eligible for a 45Y Production Tax Credit (PTC) for the first ten years of the plant's life. Battery storage facilities are assumed to be eligible for a 30% Investment Tax Credit (ITC).

Retrofitted hydrogen combustion turbine: LCOE ranges between $288 - $483 per MWh, primarily driven by the estimation range around fuel costs. This configuration assumes existing gas power plants are retrofitted with 100% clean renewable hydrogen-capable turbines, which minimizes the capital cost compared to a new-build facility. However, feedstock cost (based on the LCOH of Angeles Link) is the primary driver of the levelized cost, making up about 75% of the LCOE.

Battery storage (12-hour): LCOE ranges between $419 - $923 per MWh, primarily driven by the estimation range around battery system capital expenditure (CapEx). Upfront capital costs make up 70% of the LCOE, as the 12-hour battery storage configuration is modeled based on three 4-hour duration stacks, which increases the capital cost of the system to provide longer duration reliability services. A key assumption underlying the modeling of 12-hour battery storage is the effective capacity factor (or the percentage of all hours of a typical year during which the battery is discharging). To ensure an equivalent comparison to a hydrogen peaker plant capable of providing longer duration reliability services, an effective capacity factor (near 10%) was applied to the hypothetical battery configuration.

This assumption is indicative of a commercial model in which the battery system would be required to remain available to discharge during longer duration reliability events and thus unable to discharge more frequently to engage in energy arbitrage or other grid services. This is not common practice in the market today and is an indication of why there are few readily available clean energy solutions for longer duration reliability needs of the power system. Additional rationale for choosing a 12-hour battery storage system is detailed in the Alternatives Study.

4.2.1.2.2. Key Sensitivities: Capital Costs and Fuel/Charging Cost

To reflect the potential variability in cost assumptions for different alternatives, as well as to consider the impact of future advancements in battery and hydrogen turbine technology, a sensitivity analysis was performed on the key inputs during the LCOE analysis. Capital expenses and fuel costs were identified as the two main factors influencing the sensitivities.

Capital Cost

The capital cost of the retrofitted hydrogen turbine was derived from a National Petroleum Council (NPC) report, [103] which captured industry consensus on capital expenditures. When considering the installed cost, the capital expenditures for a retrofitted turbine are expected to be less than those for a new-build facility, as the retrofit takes advantage of existing infrastructure. A range has been incorporated to accommodate potential changes in turbine efficiency and design as these retrofitted facilities become operational after 2030.[104]

The capital cost of battery storage is based on estimates for new-build lithium-ion battery facilities (the assumptions for these estimates are detailed further in Appendix 7.3.2.2). A range has also been applied to the battery storage capital cost to account for potential cost variability. The battery capital costs shown in Figure 11 below are high because they reflect the increase in capital costs due to a tripling of a typical 4-hour battery facility to achieve the 12-hour capability.

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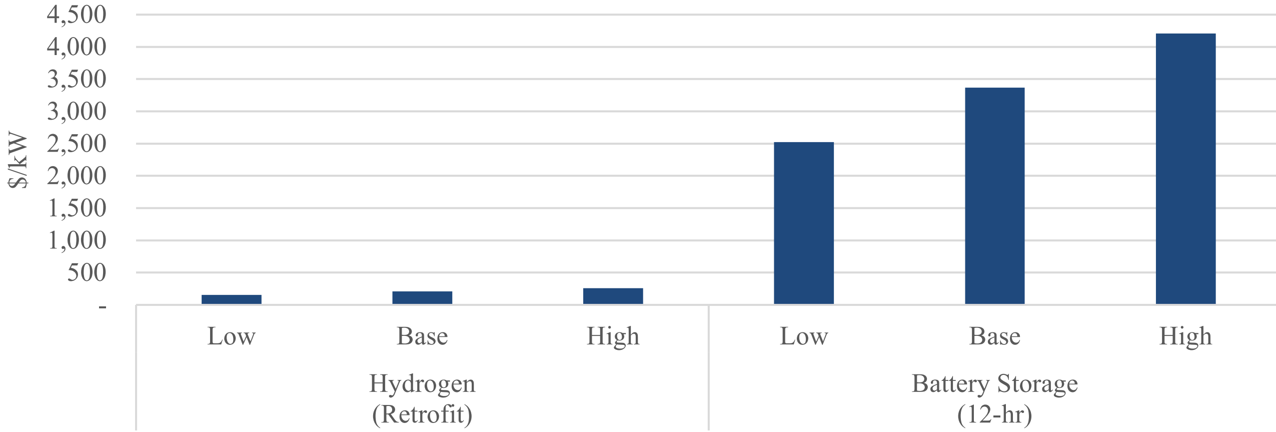
[103] National Petroleum Council. (2024). Harnessing Hydrogen: A Key Element of the U.S. Energy Future.
[104] Based on inputs from third-party models and NPC.

Figure 11: Capital Cost of Hydrogen Turbine vs. Battery Storage[105]



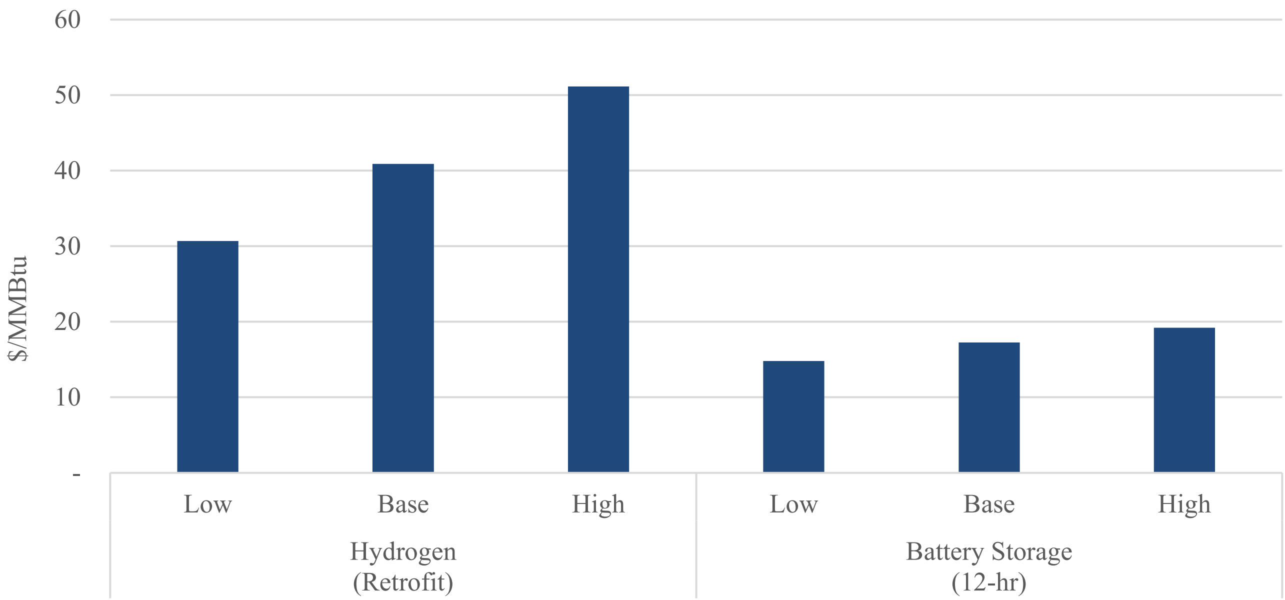
Fuel/Charging Cost

Fuel or charging costs are key in determining the cost-effectiveness of a power plant, as they constitute a significant portion of the operational costs for any facility. For molecular fuels, these costs are largely determined by the production and distribution cost of the fuel and the efficiency of the turbines. For the purpose of this study, the hydrogen fuel cost assumed for hydrogen turbines is the LCOH of Angeles Link. For battery facilities, charging costs are influenced by the generation and distribution costs of electricity, roundtrip efficiency, and the number of discharge cycles. A sensitivity range is applied to both hydrogen fuel delivery costs and electric charging costs as shown in Figure 12.

For hydrogen, this sensitivity considers potential changes in production and delivery costs across the value chain. For the cost of charging battery storage facilities, this sensitivity considers the variability in possible charging sources (i.e., from the grid or from a co-located solar or other renewable facility).

[105] Refer to Appendix 7.3.2.2 for the underlying data assumptions reflected in the Low, Base and High sensitivity cases.

Figure 12: Fuel/Charging Cost of Hydrogen Turbine vs. Battery Storage[106]



4.2.1.2.3. Non-Economic Considerations

As discussed in the Alternatives Study, the increasing share of intermittent wind and solar generation creates challenges for grid reliability, requiring a combination of clean firm generation and LDES. Clean renewable hydrogen can support clean firm generation as well as LDES needs through the development and use of hydrogen storage resources or linepack. Battery storage facilities (4-hour discharge duration resources) are better equipped to address only shorter-duration ramping and grid services. Emerging technologies like compressed air energy storage (CAES) and vanadium redox flow batteries (VRFB) may serve as better candidates for LDES than lithium-ion in the long run, however their adoption is uncertain, as discussed in the Alternatives Study. Unblended clean hydrogen-capable turbines have a technology readiness level (TRL) score of seven, indicating that they are close to commercial operations.[107] Various fuel-flexible hydrogen turbines are under development with Tier 1 original equipment manufacturers (OEMs) and are expected to be commercially available by 2030. For example,

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[106] Refer to Appendix 7.3.2.2 for the underlying data assumptions reflected in the Low, Base, and High sensitivity cases.
[107] The Technology Readiness Levels (TRLs) published by the International Energy Agency. See Appendix in Alternatives Study for additional detail on the TRL scores.

a pilot project in France successfully demonstrated a gas turbine operating with 100% renewable hydrogen.[108]

4.2.1.3. Industrial – Food & Beverage and Cement

In industrial use cases, Angeles Link has the potential to serve the F&B and cement sectors to support the decarbonization of hydrogen-fueled ovens, fryers, and cement kilns. This section compares the hydrogen end-use technology with the electrified equivalent. For the purpose of this study, the cost effectiveness analysis focuses exclusively on the fuel (or electricity) costs associated with operating the equipment and does not consider the capital costs of equipment replacement or other non-fuel operating costs.[109] A direct comparison of fuel and electricity costs on a $/MMBtu basis highlights the costs of switching to the alternative fuels in these industrial use cases. Sensitivity ranges were applied to reflect the range of uncertainty in the cost of fuel and electricity. The implications of these sensitivities are discussed in Key Sensitivities sub-section 4.2.1.3.2. Additional details on the fuel cost modeling assumptions can be found in Appendix 7.3.2.4.

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[108] HYFLEXPOWER Project – Siemens Energy.

[109] The capital costs of equipment replacement are assumed to be similar across hydrogen-fueled and electrically powered equipment in these industries. This was a simplifying assumption made for the purpose of this study given the small volumes of hydrogen demand projected in the Demand Study for the food & beverage and cement sectors.

Table 9: Configurations and Cost Metrics for Cement and Food & Beverage

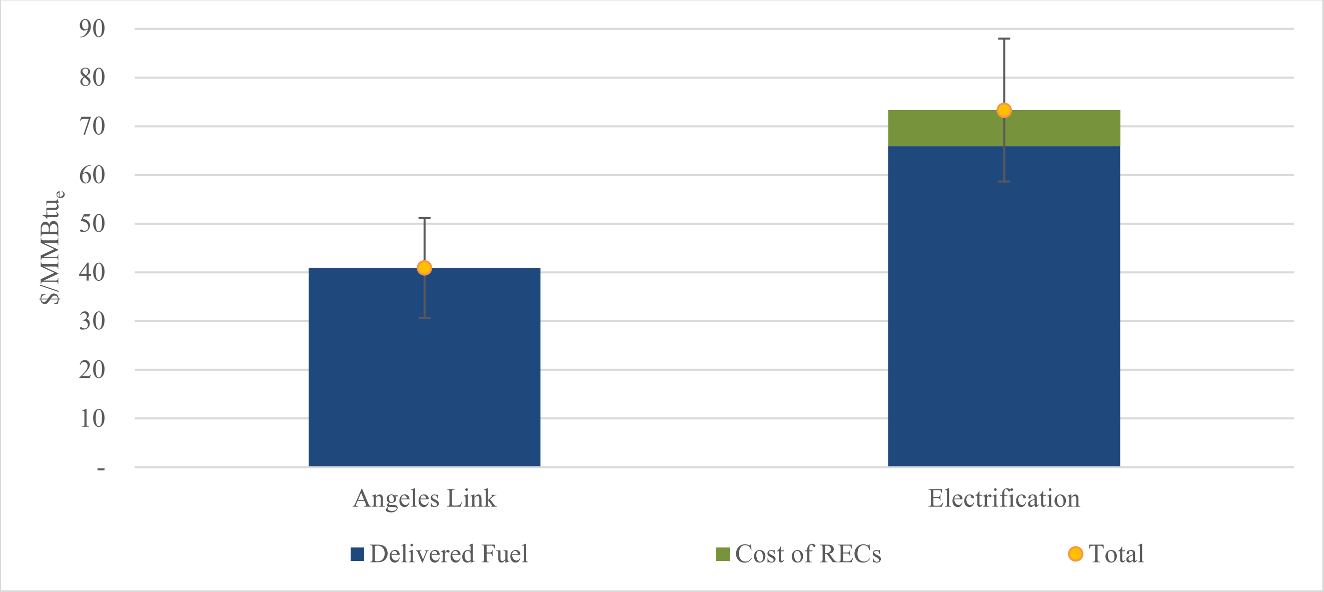
<table>
<tr><th>Use Case</th><th>Alternative</th><th>Technology Application</th><th>Cost Metric</th></tr>
<tr><td rowspan="2">Cement
High Process Heat</td><td>Angeles Link</td><td>Hydrogen Kiln</td><td rowspan="4">Fuel Cost ($/MMBtu$_e$)[110]</td></tr>
<tr><td>Electrification</td><td>Electric Kiln</td></tr>
<tr><td rowspan="2">Food & Beverage
Low-Medium Process Heat</td><td>Angeles Link</td><td>Hydrogen Ovens/Fryers</td></tr>
<tr><td>Electrification</td><td>Electric Ovens/Fryers</td></tr>
</table>

4.2.1.3.1. Cost Analysis Results

The findings indicate that clean renewable hydrogen delivered through Angeles Link serving kilns for cement processing and ovens and fryers for the F&B sector offers a cost-effective solution when compared to electrification. This is driven by high electricity tariffs for industrial customers in California compared to the equivalent cost (on a $/MMBtu basis) of delivered hydrogen. Additional findings from the fuel cost comparison are discussed in Figure 13.

[110] This reflects the LCOH of Angeles Link converted to MMBtu based on the energy value of hydrogen. For electrification, the fuel cost reflects industrial electricity tariffs in the Central and Southern California region converted to MMBtu based on the energy value of electricity.

Figure 13: Cost Effectiveness: Food & Beverage and Cement (Hydrogen and Electrification) (2030)[111]



Angeles Link: The cost of fuel delivered to F&B and cement facilities ranges from $31-$51 per MMBtu, reflecting an estimation range for the delivered cost of hydrogen. The drivers of this delivered fuel cost are discussed in the Delivery Alternatives section (see section 4.1) of this study.

Electrification: The cost of electricity ranges between $59-$88 per MMBtu, reflecting an estimation range for future industrial electricity tariffs. This reflects industrial electricity tariffs in the Central and Southern California region converted to MMBtu based on the energy value of electricity, in addition to the cost of procuring RECs to offset the carbon footprint of grid electricity.

4.2.1.3.2. Key Sensitivities: Fuel Cost

As both F&B and cement are primarily output-based industries, the cost of fuel is a significant driver for the operational costs for the industries as a whole. The efficiency of the equipment that runs on these fuels would determine the overall fuel costs for the facility. The analysis focused exclusively on the unit cost associated with switching fuels to run the applicable equipment in a F&B and cement facility. A

[111] As electric kilns, fryers, and ovens consume electricity from the grid, the cost of procuring renewable energy credits (RECs) was added to ensure the emissions profile is clean and comparable to the clean renewable hydrogen delivered by Angeles Link.

sensitivity range is applied to both energy sources to reflect a reasonable range of uncertainty around future costs.

For clean renewable hydrogen, this sensitivity considers potential changes in production and delivery costs across the value chain. For electrification, this sensitivity considers potential changes to the future California generation portfolio as well as T&D investment.

4.2.1.3.3. Non-Economic Considerations

In the F&B sector, electric-powered equipment, including fryers and ovens, are commercially available today. Hydrogen equipment suitable to decarbonize the diverse set of needs for this sector is not as commercially widespread. For low temperature heating applications that would be applicable in F&B equipment like ovens and fryers, hydrogen and electrification both score nine in the International Energy Agency's (IEA) TRL, representing different stages of market uptake in select environments.[112]

In the cement industry, hydrogen and electric kilns are at a similar stage of development with both technologies in pilot stage projects. Both have achieved a rating of five on the TRL scale.[113]

4.2.2. Cost Effectiveness of Angeles Link vs. CCS

Angeles Link was analyzed relative to CCS across the same set of CCS use cases assessed in the Alternatives Study, as detailed below:

- **Power**: Hydrogen-fueled combustion plant vs. natural gas-fueled combustion plant with CCS.
- **Cogeneration**: Hydrogen-fueled cogeneration facility vs. natural gas-fueled cogeneration facility with CCS.
- **Cement**: Hydrogen-fueled kilns vs. natural gas-fueled kilns with CCS.
- **Refineries**: Angeles Link-delivered clean renewable hydrogen for refinery process needs vs. addition of CCS to current unabated hydrogen supply from existing natural gas-fueled steam methane reformers (SMRs).

[112] IEA TRL Scores.
[113] Ibid.

4.2.2.1. Power and Cogeneration

The power and cogeneration use cases are presented together since the cost-effectiveness considerations are similar. In both sectors, Angeles Link is evaluated based on a retrofitted hydrogen turbine combustion facility (i.e., replacing existing natural gas turbines with turbines capable of running on hydrogen fuel), while CCS is analyzed based on a natural gas plant retrofitted with CCS. Both the power and cogeneration facilities are assumed to run at high capacity factors (detailed in the assumptions in Appendix 7.3.2.2) to serve a baseload-like profile. The costs presented for CCS in this section assume a 90% capture rate, which is compliant with the latest U.S. Environmental Protection Agency (EPA) requirements.[114] An LCOE analysis was then conducted to determine the cost effectiveness of the two alternatives in the power and cogeneration sectors.

Table 10: Configurations and Cost Metrics for Power and Cogeneration

Use Case	Alternative	Technology Application	Cost Metric
High Capacity Factor / Baseload Units	Angeles Link	Hydrogen Turbine (retrofit)	Levelized Cost of Electricity (LCOE) ($/MWh)
	CCS	Gas Turbine with CCS (retrofit)	

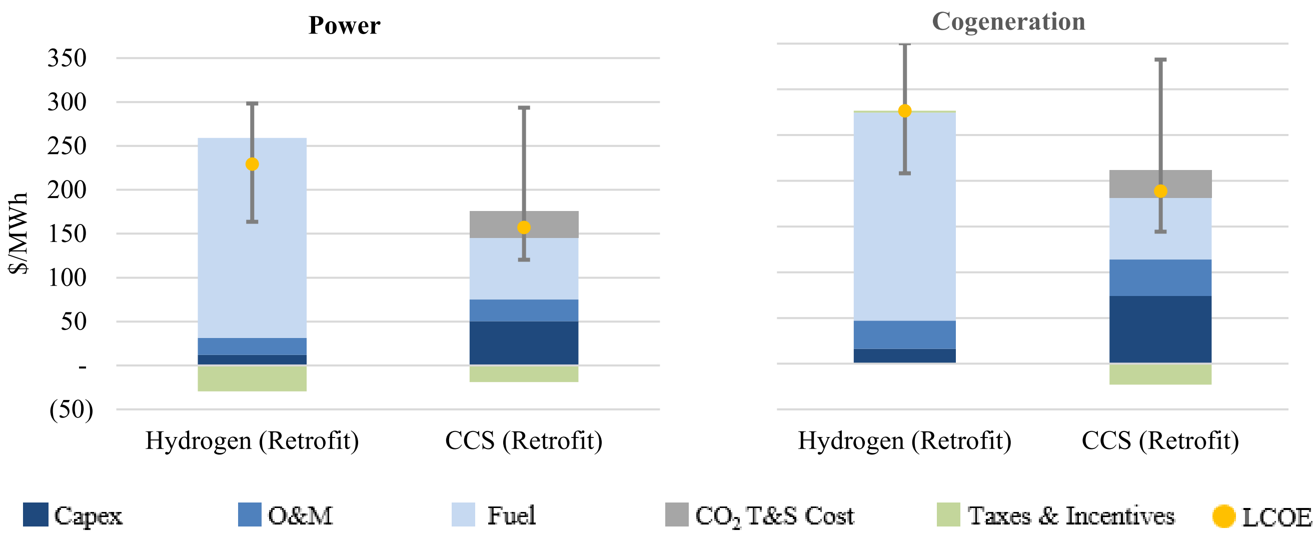
The LCOE analysis was performed using third-party models,[115] leveraging market-based asset level and system cost data to compare these alternatives. Any uncertainties in the underlying capital and operating costs, fuel cost, operating metrics, and potential CO_2 transport and sequestration tariffs (applicable only to CCS) were captured in a sensitivity analysis. The implications of these sensitivities are discussed in the Key Sensitivities sub-section. Additional details of the LCOE modeling assumptions can be found in Appendix 7.3.2.2.

[114] EPA ruling – Carbon Pollution Standards for Fossil-Fired Power Plants
[115] Third-party LCOE models.

4.2.2.1.1. Cost Analysis Results

The results from the LCOE analysis show that a CCS retrofit can be more cost effective compared to a retrofit hydrogen turbine in both power and cogeneration use cases, assuming site suitability for CCS equipment and access to CO_2 transport and sequestration infrastructure.[116] The analysis showed that the higher cost of hydrogen fuel outweighs the higher capital cost associated with installing carbon capture equipment for CCS and the additional cost of CO_2 transport and sequestration. The sensitivity ranges include potential variance in the capacity factors for CCS retrofit plants, accounting for the possible additional energy requirements of operating CO_2 capture equipment. Detailed assumptions and sensitivity ranges of inputs are provided in the Appendix 7.3.2.3. The component breakdown of the LCOE across the power and cogeneration sectors is shown below in Figure 14.

Figure 14: Cost Effectiveness: Power & Cogeneration (Hydrogen and CCS) (2030)



Note: "T&S" refers to CO_2 transport and sequestration.

Retrofitted hydrogen combustion turbine: LCOE ranges between \$164 - \$298 per MWh for the power use case and \$208 - \$350 per MWh for the cogeneration use case, driven primarily by the range in delivered hydrogen cost. The cost of hydrogen fuel delivered from Angeles Link to operate the

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[116] CCS adoption will be heavily dependent on site level and regional factors, including geospatial constraints, remaining facility life, and access to CO_2 transport and sequestration infrastructure near point sources, all of which could impact technical feasibility and cost.

turbines is the primary driver of the LCOE, making up about 80% of the total LCOE across both use cases.

CCS retrofit: LCOE ranges between \$120 - \$293 per MWh for power applications and \$144 - \$333 per MWh for cogeneration applications. The upfront capital cost and fuel cost are the primary drivers of the LCOE for a CCS plant, with the range driven primarily by variation in potential CO_2 transport and sequestration tariffs faced by end users.

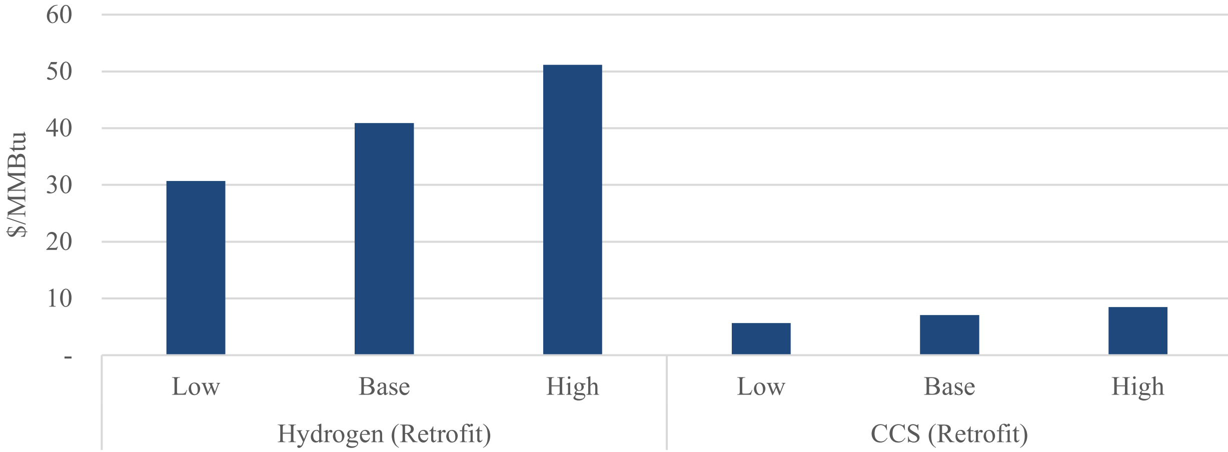
4.2.2.1.2. Key Sensitivities: Fuel Cost and CO_2 Transport & Storage Cost

A series of sensitivity analyses were conducted to account for the uncertainty surrounding the cost assumptions for the alternatives. Two variables were identified as the primary factors influencing the outcome—fuel cost and CO_2 transport and sequestration cost.

Fuel Cost

The cost-effectiveness of a power plant heavily relies on fuel costs, as they make up a substantial portion of the operational expenses for any facility. The costs associated with molecular fuels, such as hydrogen, are influenced by both the expenses of the feedstock and the efficiency of the turbines. A lower efficiency in the turbines results in higher fuel costs, as a larger quantity of feedstock is required to produce the same level of output. The study applied a sensitivity range to the costs of hydrogen and natural gas. The variation in the natural gas cost reflects a range of market prices and potential future industrial natural gas tariffs, while the variation in hydrogen cost reflects an estimation range for the production and delivery costs of clean renewable hydrogen.

Figure 15: Fuel Cost Variation Across Hydrogen and CCS Alternatives in Power and Cogen[117]



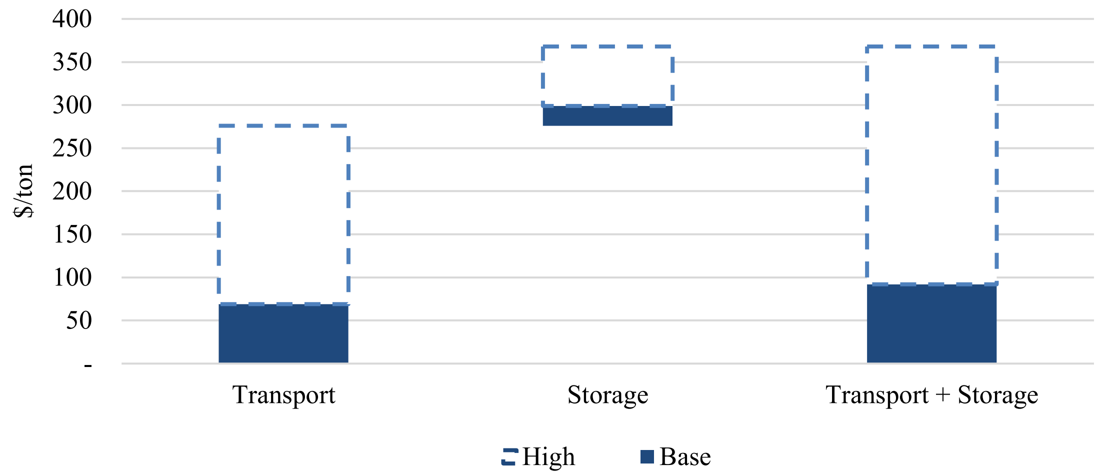
Economics of CO_2 Transport and Sequestration

The cost of transporting and storing captured CO_2 from a CCS facility is a key determinant of cost-effectiveness. For this study, transport is assumed to be provided by a CO_2 pipeline system, with storage provided by underground CO_2 reservoirs. The cost of CO_2 transport and sequestration services for power generation or cogeneration facilities is determined by the capital and operating costs associated with the assets, as well as integrating point source CO_2 capture from multiple end-use users. Some of the power and cogeneration facilities in Central and Southern California are situated near industrial clusters, which could support infrastructure development for a hypothetical CO_2 transport and sequestration system.

In this analysis, the CCS infrastructure was assumed to be fully utilized in the base case, with a higher cost sensitivity case representing lower utilization of the system. Figure 16 below shows the variation in CO_2 transport and sequestration costs.

[117] Refer to Appendix 7.3.2.2 for the underlying data assumptions reflected in the Low, Base and High sensitivity cases.

Figure 16: Variations in CO_2 Transport and Sequestration Costs for CCS Facilities[118]



4.2.2.1.3. Non-Economic Considerations

CCS provides a potential pathway to achieve the State's carbon-neutral targets by 2045, but it is reliant on sufficient scale and integration of supporting infrastructure to collect, transport, and sequester CO_2. In the power and cogeneration sectors, CCS can be cost-effective, but adoption is expected to be reliant on site-level and regional factors that are beyond the scope of this study, including geospatial constraints, remaining facility life, and access to CO_2 transport and sequestration infrastructure near point sources, all of which could impact technical feasibility and cost.

4.2.2.2. Industrial – Cement

In the cement sector, hydrogen delivered by Angeles Link and CCS are assessed primarily for the decarbonization of the high heat needs for processing cement. As discussed in the Demand study, SB596 specifically mandates the decarbonization of the cement industry in California. Both CCS and hydrogen can play a role in supporting the goals of this legislation. As discussed in the Alternatives Study, CCS has the potential to address a broader range of emissions sources within a cement facility — including clinker production[119] — in addition to the kiln. However, this analysis focused on the cost of fuel

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[118] The solid bars represent the base case or expected costs for CO_2 transport and sequestration. The dashed lines show how the costs of transporting and storing CO_2 could increase under lower integration scenarios.
[119] Clinker is a hard nodular material caused when raw materials such as limestone, chalk, shale, clay and sand react at high temperatures. Source: EPA.

associated with cement kilns. In the cement sector, hydrogen-fueled kilns (with hydrogen supplied by Angeles Link) are compared to gas kilns with CCS equipment added (the CCS alternative). The cost effectiveness analysis focuses exclusively on the fuel costs associated with operating the equipment and does not consider the capital costs of equipment replacement or other non-fuel operating costs other than an assumed CO_2 transport and sequestration tariff added to fuel costs for the CCS alternative[120]. A direct comparison of fuel costs on a $/MMBtu basis was carried out, with sensitivity ranges added to reflect the range of uncertainty in the cost of fuel and the cost of carbon transport and sequestration. The implications of these sensitivities are discussed in the Key Sensitivities sub-section below. Additional details on the modeling assumptions can be found in the Appendix 7.3.2.

Table 11: Configurations and Cost Metrics for Cement

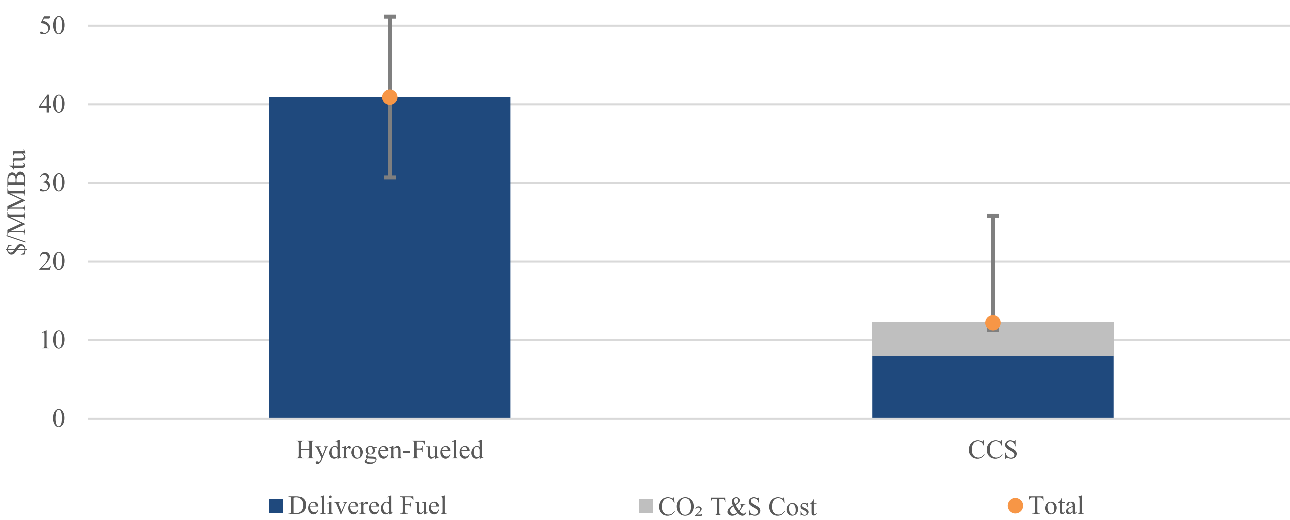
Use Case	Alternative	Technology Application	Cost Metric
Cement High Process Heat	Angeles Link	Hydrogen Kiln	Fuel Cost ($/MMBtu$_e$)
	CCS	Gas Kiln with CCS	

4.2.2.2.1. Cost Analysis Results

The analysis reveals a gap in cost parity when comparing incumbent fuels such as natural gas with clean renewable hydrogen supplied by Angeles Link. The cost-effectiveness of CCS is driven by this fuel cost disparity, provided that the site is suitable for CCS equipment and there is sufficient access to CO_2 transport and sequestration infrastructure. The following additional findings are presented and discussed in Figure 17.

[120] For the cement sector analysis, the capital costs associated with hydrogen kiln retrofits and CO_2 capture equipment were not considered, nor were the costs of incremental energy to power the capture equipment. It is possible that these considerations could impact the relative cost effectiveness of clean renewable hydrogen and CCS in the cement sector.

Figure 17: Cost Effectiveness: Cement (Hydrogen and CCS) (2030)



Note: "T&S" refers to CO_2 transport and sequestration.

Angeles Link: The cost of fuel delivered to cement facilities ranges from $29 - $49 per MMBtu. This reflects the delivered cost of hydrogen from Angeles Link.

CCS: The cost ranges between $11 - $26 per MMBtu. This reflects the cost of natural gas delivered to industrial users in Central and Southern California, measured by prices at SoCal Citygate,[121] the major natural gas price hub in Southern California, in addition to the cost of transport and sequestration of captured CO_2 from the cement facility.

4.2.2.2.2. Key Sensitivities: Fuel Cost and CO_2 Transport and Sequestration Costs

The cost of alternatives for a cement facility is highly dependent on both fuel cost and the cost of CO_2 transport and sequestration infrastructure. The study applied a sensitivity range to the costs of hydrogen and natural gas. The variation in the natural gas price reflects a range of market prices and potential future industrial natural gas tariffs, while the variation in hydrogen cost reflects an estimation range for the production and delivery costs of clean renewable hydrogen. A multiplier was also added to CO_2

[121] Forecasted natural gas prices at SoCal Citygate were derived from Wood Mackenzie North America Gas Service.

transport and sequestration infrastructure costs to reflect uncertainties in the cost and utilization of the infrastructure.

4.2.2.2.3. Non-Economic Considerations

Based on the criteria evaluated in the Alternatives Study, both Angeles Link and CCS offer potentially viable solutions for the cement industry. While both technologies are currently being demonstrated in pilot projects[122] CCS has a scaling advantage of addressing the wider cement emissions stack to help advance SB 596 goals for California to enable decarbonization of the cement sector by 2045.[123] Adoption of CCS in the cement sector will depend on factors such as the availability of space for additional equipment within the plant boundary, access to supporting transport and sequestration infrastructure, and proximity to other industrial clusters for efficient integration and lower cost of transport and sequestration infrastructure.

4.2.2.3. Industrial – Refineries

The allocation of capital towards decarbonization efforts in the refinery sector will depend on the future demand for refinery products. Currently, the refineries operating in Central and Southern California primarily use unabated hydrogen for hydrocracking and sulphur removal processes (made from natural gas using SMRs) that does not meet the definition of clean renewable hydrogen. Available decarbonization pathways for this process hydrogen include clean renewable hydrogen (which could be supplied by Angeles Link) and the conversion of current unabated hydrogen to abated hydrogen with CO_2 capture (by adding CCS to existing SMR supply). In this study, clean renewable hydrogen (supplied by Angeles Link) is compared to the addition of CCS infrastructure to existing unabated hydrogen supply. A direct comparison of LCOH was carried out and sensitivity ranges were added to reflect uncertainties in LCOH and in the cost of CO_2 transport and sequestration infrastructure. The implications of these sensitivities are discussed in the Key Sensitivities sub-section 4.2.2.3.2. Additional details of the modeling assumptions can be found in the Appendix 7.3.2.6.

[122] Demonstration projects, TRL 5-7. The Technology Readiness Levels (TRLs) published by the International Energy Agency.
[123] Net-Zero Emissions Strategy for the Cement Sector | California Air Resources Board.

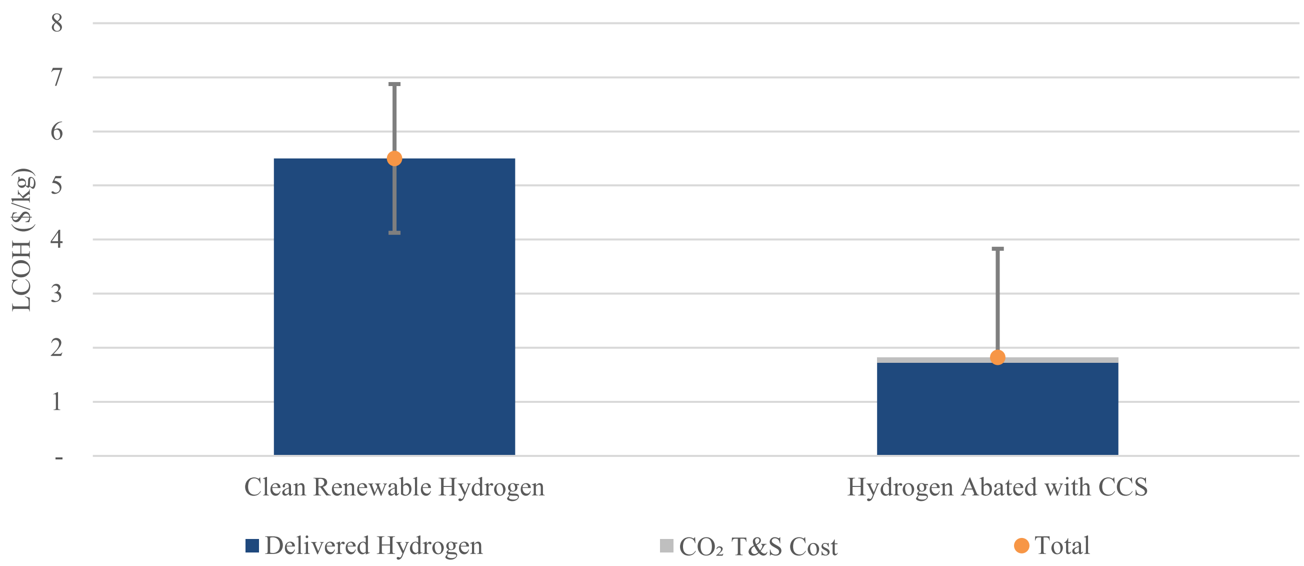
Table 12: Configurations and Cost Metrics for Refineries

Refinery Use Case	Alternative	Technology Application	Cost Metric
Process Hydrogen	Angeles Link	Clean Renewable Hydrogen	LCOH ($/kg)
	CCS	Hydrogen Abated with Carbon Capture	

4.2.2.3.1. Cost Analysis Results

The analysis showed that the addition of CCS to existing unabated hydrogen supply is likely more cost effective for refinery hydrogen compared to clean renewable hydrogen delivered from Angeles Link, assuming site suitability for the addition of CCS equipment and access to CO_2 transport and sequestration infrastructure. Additional findings are discussed below:

Figure 18: Cost Effectiveness: Refineries (Clean Renewable Hydrogen and CCS) (2030)



Note: “T&S” refers to CO_2 transport and sequestration. Delivered hydrogen for the CCS alternative includes the cost of capture equipment.

Angeles Link: The cost of hydrogen delivered to refineries ranges from $3.9 - $6.6 per kg. This reflects the LCOH from Angeles Link.

CCS: The cost of hydrogen delivered to refineries ranges between $1.8 - $3.8 per kg. This reflects the input cost of natural gas delivered to near-site SMRs, measured by prices at SoCal Citygate,[124] in addition to the cost of transport and sequestration of captured CO_2 from the refinery facility.

4.2.2.3.2. Key Sensitivities: Fuel Cost and CO_2 Transport and Sequestration Costs

Like cement, the LCOH analysis for refinery hydrogen is sensitive to both fuel cost and the cost of CO_2 transport and sequestration infrastructure. The study applied a sensitivity range to the costs of hydrogen and natural gas. The variation in the natural gas price reflects a range of market prices and potential future industrial natural gas tariffs, while the variation in hydrogen cost reflects an estimation range for the production and delivery costs of clean renewable hydrogen. A multiplier was also added to CO_2 transport and sequestration infrastructure costs to reflect uncertainties in the cost and utilization of the infrastructure.

4.2.2.3.3. Non-Economic Considerations

Adding CCS to existing unabated hydrogen supply could offer a potential decarbonization solution for the refinery sector. It allows for the capture of point source CO_2 within the facility, and refineries offer the necessary scale to make use of a larger CO_2 transport and sequestration infrastructure. Nevertheless, every refinery may adopt a unique strategy for reducing CO_2 emissions in their hydrogen supply to comply with California's decarbonization goals. The viability of CCS in some refineries may be challenging due to geospatial limitations, the remaining operational life, or the economic performance of the facility. CCS retrofits for refinery process use versus the use of clean renewable hydrogen will also be influenced by the availability of CO_2 transport and sequestration infrastructure and enabling state policy.

[124] Citygate is a point or a measuring station at where a gas utility receives gas from a natural gas pipeline company or transmission system. Source: EIA.

4.2.3. Cross-Sector Takeaways for Non-Hydrogen Alternatives

This study found that clean renewable hydrogen delivered by Angeles Link is cost effective relative to electrification for Phase 1 purposes. While CCS can be more cost effective than Angeles Link in some use cases, it requires specific conditions for adoption, including access to CO_2 transport and sequestration infrastructure, site-level capacity for CO_2 capture equipment, and end user proximity to wider industrial clusters to drive scale.

- In the **mobility** sector, FCEVs (supplied by Angeles Link) were found to be cost-effective relative to BEVs (the electrification alternative) for long-haul use cases with en-route refueling needs like Class 8 sleeper cabs and transit buses. Depending on fuel and charging costs, FCEVs can also be cost-effective for other heavy-duty use cases like Class 8 drayage and day cabs. CCS is not a technically viable alternative that could be deployed at scale to capture tailpipe emissions for the mobility sector (which accounts for approximately 40% of estimated hydrogen demand by 2045 according to the Demand Study).
- In the **power** sector, hydrogen combustion power plants (with hydrogen supplied by Angeles Link) were found to be cost-effective relative to 12-hour lithium-ion battery energy storage facilities (the electrification alternative) for lower capacity factor reliability use cases (peakers). Both hydrogen combustion turbines (with hydrogen supplied by Angeles Link) and CCS (added to gas power plants) can be cost-effective for higher capacity factor use cases (baseload), although CCS adoption is reliant on site-level capacity for CO_2 capture equipment and access to CO_2 transport and sequestration infrastructure.
- In **industrial** sectors, clean renewable hydrogen delivered by Angeles Link was found to be cost-effective relative to electrification for medium- and high-heat industrial needs due to high industrial electricity tariffs in California. CCS was generally found to be more cost effective than Angeles Link for cogeneration, refinery, and cement applications,[125] although CCS adoption is reliant on site-level capacity for CO_2 capture equipment and access to CO_2 transport and sequestration infrastructure, among many other variables.

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[125] Particularly in the cement sector, CCS is well-positioned to support California's decarbonization goals set out in SB 596 due to its ability to address the full scope of cement facility emissions.

5. Stakeholder Comments

The Cost Effectiveness Study received feedback from various stakeholders engaged in the Angeles Link PAG and CBOSG processes, including feedback on the Preliminary Findings for the Cost Effectiveness Study and draft report preview during the June 2024 PAG and CBOSG meetings. All comments, as captured in the SoCalGas Angeles Link Quarterly Report to the CPUC, reflect diverse perspectives from organizations such as the Environmental Defense Fund (EDF), Air Products, Communities for a Better Environment (CBE), among others. Written stakeholder comments are responded to in SoCalGas's quarterly reports, which are accessible on SoCalGas's website.[126]

Key themes in the feedback included:

- Comments regarding the evaluation of retail (commodity) price of hydrogen;
- Requests for information about the total investment cost required to build Angeles Link;
- Requests to provide the underlying input assumptions informing the preliminary findings;
- Request to evaluate a High Voltage Direct Current (HVDC) electric transmission system as a potential alternative to support in-basin hydrogen production;
- Comments on the role of hydrogen to offset traditional fuels in heavy duty end-use equipment and trucking in order to meet the decarbonization and energy reliability needs;
- A preference for the least disruptive hydrogen delivery method with durability, and the ability to take on a heavier duty cycle and payload (in the mobility sector); and
- Comments noting that while clean electricity is crucial for reducing emissions, the constraints of electrical infrastructure emphasize the need to simultaneously advance and broaden the use of clean fuels to attain a reliable, resilient, and economically viable net-zero energy future.

With respect to the stakeholders' comments related to providing a retail (commodity) price of hydrogen, the Cost Effectiveness Study assessed the levelized cost of hydrogen to ascertain the total delivered cost (including production, transport, storage, and delivery[127]). As discussed in the more detailed responses to comments in the Q1 2024 Angeles Link quarterly report, the study was not intended to address the

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[126] Angeles Link | SoCalGas.
[127] For Angeles Link and delivery alternatives, delivery corresponds to hydrogen provision via Angeles Link Central as defined by the Design Study. See Appendix 7.3.1.5.

retail (commodity) price of hydrogen, which is driven by costs for most major energy commodities and is also influenced by market-based supply and demand dynamics. Physical delivery and storage infrastructure has also been found to play a critical role in driving convergence between commodity costs and market prices.[128]

With respect to comments requesting information about the total investments needed to build Angeles Link, please refer to the Design Study, Section 6 (Cost Estimates), which includes a high-level cost estimate for constructing potential conceptual Angeles Link configurations.[129] A more detailed assessment of Angeles Link construction costs will be performed in future phases of Angeles Link planning. For purposes of evaluating the cost effectiveness of various hydrogen delivery alternatives in this Cost Effectiveness Study, SoCalGas leveraged the LCOH methodology to evaluate cost effectiveness, which includes the lifetime asset costs associated with hydrogen production, transport, storage, and delivery.

In response to stakeholders' request to provide the underlying input assumptions informing the findings of this Cost Effectiveness Study, please see Section 3 (Study Methodology Overview) and Section 7 (Appendix) of this report detailing the key techno-economic input assumptions and considerations informing the cost effectiveness evaluation.

In response to the request to assess the role of a High Voltage Direct Current (HVDC) electric transmission system as a potential system alternative to support in-basin hydrogen production, please refer to Appendix 7.5.2, which discusses the potential role of a HVDC system. As described therein, electricity can be transmitted via a HVDC system instead of a High Voltage Alternating Current (HVAC) transmission system. For the purpose of this study, the T&D with in-basin hydrogen production alternative selected a 500kV AC transmission system to enable system and operational compatibility

[128] Current hydrogen retail pricing in the California market is specific to hydrogen delivered via gaseous and liquid trucks in relatively small quantities for consumption primarily in the passenger FCEV market. With an anticipated increase in clean renewable hydrogen supply and connective infrastructure, it is expected that the costs of hydrogen on a delivered basis (inclusive of production, transmission, storage, and delivery, as well as additional overhead costs not considered within the scope of this study) will play a significant role as a price setting mechanism for clean renewable hydrogen. As discussed in the more detailed responses to comments in the Q1 2024 Angeles Link quarterly report, the study was not intended to address the retail (commodity) price of hydrogen, which is driven by costs for most major energy commodities and is also influenced by market-based supply and demand dynamics.
[129] Please refer to Table 17 (Design Study).

with California's predominantly HVAC electric grid system and with the intent to support the system's reliability and resiliency requirements.

In response to feedback to address the role of hydrogen to offset traditional fuels in heavy duty end-use equipment (in the industrial sector) and trucking (in the mobility sector) to meet decarbonization and energy reliability needs, please refer to Sections 5 (Evaluation of Alternatives) and Section 6 (Key Findings) of the Alternatives Study, and Section 4.2 (Cost Effectiveness of Angeles Link vs. Non-Hydrogen Alternatives) of this report. These sections detail how clean renewable hydrogen can play a potential role in the decarbonization of these hard-to-electrify end-uses while meeting their reliability needs through the development of a resilient and cost-effective hydrogen transportation system.

6. Future Considerations

The Cost Effectiveness Study as part of Phase 1 was intended to determine a methodology to measure cost effectiveness and evaluate the cost effectiveness of Angeles Link against the alternatives.

For future phases of Angeles Link, and in alignment with expected DOE requirements, a Techno Economic Analysis (TEA) may be conducted for Angeles Link. The TEA will build upon the Phase 1 results to estimate the expected levelized cost of clean renewable hydrogen delivered by Angeles Link. The TEA would be refined as more study results, performance data, and cost estimates become available. The analysis may leverage proprietary and published data, existing DOE tools, estimates or quotes from industry suppliers, and previous operational experience, as needed. This analysis would also likely define expected values of key parameters relevant to future Angeles Link operations, including expected expenditures, tax credits, operating costs, and useful life of the asset(s).

Additionally, integrating Angeles Link to support power generation (and more broadly the electric grid) requires careful consideration of the electric infrastructure, transmission capacity, interconnections, and other grid operational requirements. Hence, future phases may evaluate the role of Angeles Link to support electric system reliability and resiliency. Electric grid integration with hydrogen would support firm dispatchable power, storage, and load balancing needs and would necessitate the need for power systems modeling to evaluate system resiliency and reliability under loss of load expectations (LOLE).

7. Appendix

7.1. Formulas & Calculation Frameworks

7.1.1. LCOH Calculation Framework

LCOH Formula

$$LCOH_{\substack{Post-Tax,\\ Levered}} = \frac{\sum_{i=1}^{T} \frac{(Opex^i + Capex_L^i + Interest^i + Principal^i)}{(1+r)^i}}{\sum_{i=1}^{T} v^i \left(\frac{1+\text{inf}}{1+r}\right)^i}$$

Parameter	Description
OpEx	Operating Expenses
CapEx	Capital Expenses
DTS	Depreciation Tax Shield
L	Levered
T	Total years of Project Lifetime
Inf	Rate of Inflation (%)
r	Discount Rate (%) (required rate of return)
v	Volume of Hydrogen
Interest	Interest Loan Payments
Principal	Principal Loan Payment
i	Time, assumes each year of the operational or economic life of the relevant hydrogen infrastructure
$\sum$	Mathematical shorthand notation to indicate the sum of a number of similar terms, in this case the sum of all years of the operational or economic life of the relevant hydrogen infrastructure

LCOH figures represent the cost for new-build projects:

- Uses volumes of selected routes
- Accounts for losses across the value chain
- Assumes tax incentives (PTC) and tax shields as applicable

7.1.2. LCOE Calculation Framework

$$LCOE = \frac{(CAPEX - \sum_1^n \frac{DEP}{(1+r)^n} \times TR + \sum_1^n \frac{LP}{(1+r)^n} - \sum_1^n \frac{INT}{(1+r)^n} \times TR + \sum_1^n \frac{AO}{(1+r)^n} \times (1-TR) + \sum_1^n \frac{Fuel\,Cost}{(1+r)^n} \times (1-TR))}{\sum_1^n \frac{Initial\,MWh \times (1-Degradation)^n}{(1+r)^n}}$$

Parameter	Description
$CapEx$	Capital Expenses
$\sum$	Sum
n	Life of asset in years
DEP	Depreciation
r	Discount Rate
TR	Tax Rate
LP	Loan Payment
INT	Interest
AO	Annual operation cost including operation and maintenance cost or other taxes such as carbon tax
$Fuel\,Cost$	Cost of fuel
$Degradation$	System degradation rate

Table 13: LCOE Components

LCOE Category	Included Parameters	Key Notes
Capital Costs	• Includes construction, equipment, land, engineering, management, and related capital costs • Finance costs reflect after-tax equity Internal Rate of Return (IRR) hurdle rates	• Thermal generation CapEx generally provided as "overnight" costs: generation, Balance of Plant (BOP), development and interconnection costs • T&D infrastructure is not in scope
Operations and Maintenance	Ongoing costs to run the power station, including equipment and site maintenance, salaries and staff, management, and sales	• Fixed Operations and Maintenance (O&M) includes both scheduled and unscheduled maintenance
Fuel and Emissions Cost	The delivered cost of feedstock for power plants based on price outlooks over the project lifetime[130]	• No national carbon tax assumed • Delivered cost of hydrogen reflects Angeles Link LCOH
Taxes, Fees, and Incentives	May include incentives, land, regulatory, corporate, carbon, value-added or other taxes, or fees required or provided by law	• 45V Production Tax Credit (PTC) is incorporated into the Angeles Link delivered LCOH • Investment Tax Credit (ITC) is incorporated as a reduction in capital cost for battery storage • 45Q tax credit for carbon sequestration is incorporated as a reduction in operating costs for CCS facility owners

[130] Project lifetime ranges between 20-40 years depending on the technology being analyzed. See Appendix 7.3.2.2.

7.1.3. TCO Calculation Framework

$$TCO = \frac{IPC + M\&R + Ops + Fuel + Emissions + Taxes + Subsidies}{VMT}$$

Parameter	Description
IPC	Initial Purchase Cost
$M\&R$	Maintenance and Repairs
Ops	Operations Cost
$Fuel$	Fuel Cost
$Emissions$	Emissions cost
VMT	Vehicle Miles Traveled

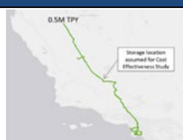
Table 14: TCO Components

TCO Category	Included Parameters	Key Notes
Initial Purchase Cost	Reflects the MSRP for transit buses and Class 8 trucks based on a fuel economy and depreciation schedule present in commercial vehicles today	Assumes the vehicle is bought outright and not financed
Maintenance and Repairs	Ongoing costs to run the vehicle, including equipment maintenance and servicing	Includes both scheduled and unscheduled maintenance
Operations	Includes labor, dwell time, and payload losses	Reflects vehicle class-specific operational characteristics
Fuel Cost	The delivered cost of hydrogen or electricity to the refueling or charging station	• Hydrogen cost reflects the Angeles Link LCOH, plus the cost of distribution and the refueling station • Electricity cost reflects California retail tariffs for charging stations, plus the cost of the charging station itself and a retail markup
Taxes and Subsidies	• Includes sales, excise, and other taxes or fees required by law • Subsidies reflect all relevant state and federal incentives	• Subsidies reflect purchase and any applicable fuel incentives, including Low Carbon Fuel Standard (LCFS)

7.2. Angeles Link Scenario Configurations and Alternatives Descriptions

7.2.1. Scenario Configurations for Angeles Link

Table 15: Angeles Link Configurations Assumptions by Scenario[131]

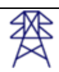
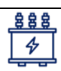
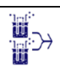
Scenario	Map	Throughput	Production (mtpa)			Storage	
			SJV	Lancaster	Blythe	Depleted Oil/Gas Fields	Salt Caverns
1		0.5 Mtpa	0.5			✓	
2		0.5 Mtpa		0.5		✓	
3		0.5 Mtpa			0.5		✓
4		1.0 Mtpa	0.5	0.5		✓	
5		1.0 Mtpa		0.5	0.5	✓	✓
6		1.0 Mtpa	0.5		0.5	✓	✓
7		1.5 Mtpa	0.75	0.75		✓	
8		1.5 Mtpa	0.5	0.5	0.5	✓	✓

[131] The Production Scenarios as defined Design Study. For additional detail on the scenarios, refer to the Design Study.

7.2.2. Description of Delivery Alternatives

As detailed in Sections 3, a core principle of the analysis was the consistent application of key project parameters across all the Delivery Alternatives, including a common hydrogen production configuration, end-user delivery system, system throughput expectations (hydrogen volumes), demand profile, and potential storage needs. The scope configurations were defined for the delivery alternatives to align with the scale, production locations and storage sites for Angeles Link Scenario 7 to the extent possible. The following sections describe the scope configuration assumptions for each delivery alternative. Table 16 provides definitions for the iconography used as a part of the diagrams and tables included for each alternative definition.

Table 16: Iconography of Infrastructure & Peripherals

Icon	Icon Name *Infrastructure & Peripherals*
	**Solar power:** *Solar panel arrays, power inverters*
	**Water for electrolysis:** *Water source, water treatment facility, water supply infrastructure*
	**Power transmission and distribution:** *High-voltage transmission lines, electrical grid infrastructure*
	**Substation:** *Transformers, control room, fencing and security, electric connections DC-AC inverters*
	**High, mid, low hydrogen production:** *Electrolyzers, H_2 purification and compression units, utility connections for water and power*
• • •	**Subscale hydrogen production:** *Electrolyzers, H_2 purification and compression units, utility connections for water and power*
	**Storage vessels** [132]**:** *Above-ground storage vessels (liquefied), utility connections for power*
	**Underground storage**[132]**:** *Underground storage in depleted oil fields or salt caverns, utility connections for power*
	**Liquefied hydrogen:** *Cryogenic liquefaction plants, utility connections for power*
	**Hydrogen regasification:** *Regasification units, heating systems, utility connections for power*
	**Pipeline:** *Pipelines, recompression stations along the pipeline, sub-stations for utility connections for power*

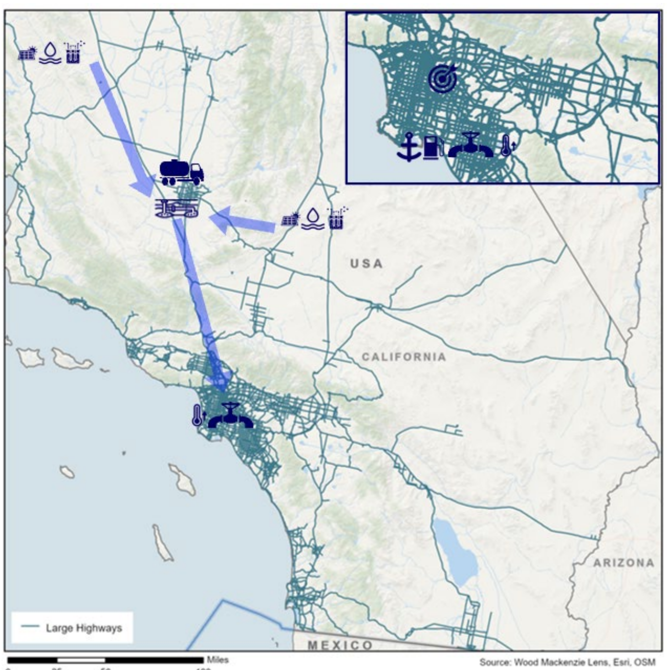
[132] Additional detail for storage considerations can be found on Appendix 7.5.1.

Icon	Icon Name *Infrastructure & Peripherals*
	Trucked hydrogen: *H_2 transport trucks (compressed or liquefied), filling and offloading stations, fuel stations*
	Shipped hydrogen: *H_2 vessels (as liquefied or methanol), port facilities for loading and unloading, reforming/cracking for methanol shipping*

7.2.2.1. Liquid Hydrogen Shipping

Production of hydrogen in Central and Northern California is transported via a pipeline to a liquefaction terminal in the nearby port. Liquid hydrogen is loaded into 10,000 cubic meter vessels (approximately 700 tonnes). These vessels transport the hydrogen to L.A. Ports, which are transferred into liquid storage vessels and then regasified at the terminal to be directly serviced at the interconnection point at the Ports. This alternative assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.

Figure 19: Liquid Hydrogen Shipping Map and Components

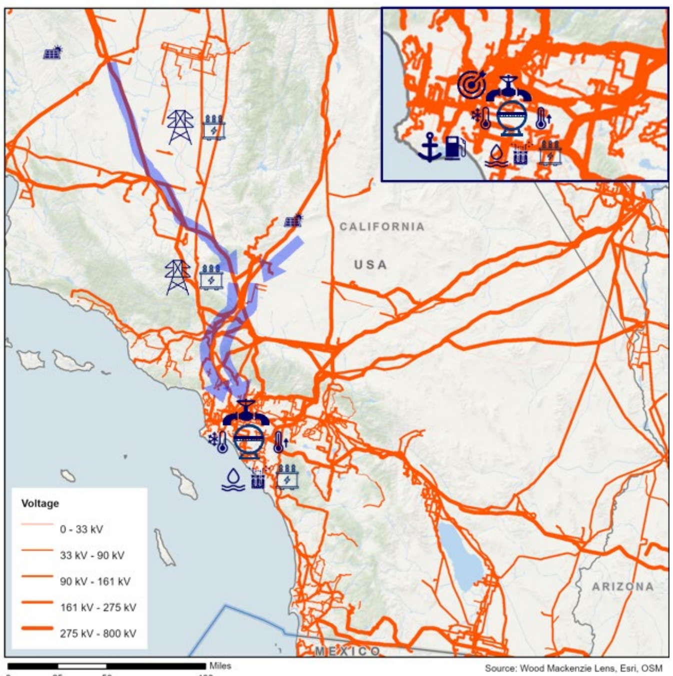


Component	Key Infrastructure for Scenario 7
Production	39.9 GW solar plants
	1.5 mtpa from Northern California 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	Above-ground storage at ports in a 135-acre, 610 liquid sphere farm
Transmission	27 ships making 2,100 round trips a year to transport 1.5 mtpa from Northern California to L.A. ports
Delivery	~80-mile delivery pipeline

7.2.2.2. Power T&D with In-Basin Production

This alternative involves transmitting renewable energy as electrons through multiple 500 kV AC electric power lines, connecting solar production sites to the L.A. Basin generally following potential conceptual Angeles Link pipeline corridors. [133] Hydrogen production would occur in-basin, with a distribution pipeline interconnection to end users, including the Ports. This assumes all new transmission lines with no interconnection to the existing grid. To meet reliability requirements, this option assumes liquid storage in-basin.

Figure 20: Power T&D with In-Basin Production Map and Components



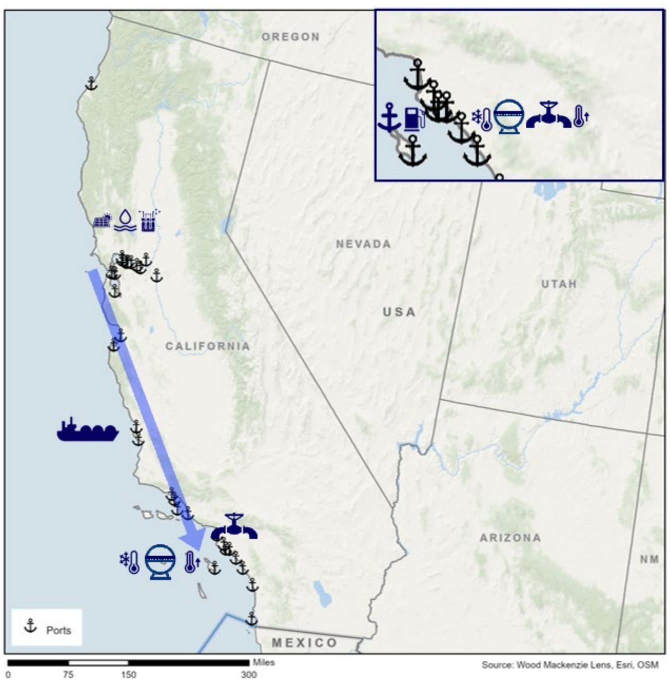
Component	Key Infrastructure for Scenario 7
Production	43 GW solar plants
	1.5 mtpa produced in L.A. basin 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	In-basin production requires 135 acres, or 610 liquid spheres for above-ground storage
Transmission	400 miles of new 500 kV transmission line corridor needed from SJV and Lancaster to L.A. basin. It needs 4 substations and 308 transformers
Delivery	~80-mile delivery pipeline

[133] A 500kV AC transmission system was selected in order to meet the capacity requirements for the Delivery Alternative. The 500kV system is largely compatible with the CAISO grid, which is mostly AC. As discussed in Appendix 7.3.1.2.4, the effective load carrying capacity for a typical 500kV AC transmission system does not exceed 3GW, rapidly declining with the transmitting distance. Hence, supporting 26.6 GW of electricity load requirement (in addition to the 1.8 GW of transmission load losses) for hydrogen production would require multiple transmission lines consisting of 10 double circuit and 1 single circuit transmission system (for a total of 21 circuits) across a 400-mile transmission corridor (accounting for a total of 2,500 miles of transmission). See Appendix 7.2.2 and 7.3.1 for additional details.

7.2.2.3. Methanol Shipping

Production of hydrogen in Central and Northern California is transported via a pipeline to a methanol conversion plant in nearby ports. The methanol is transferred onto a methanol vessel intended to transport hydrogen as methanol to L.A. Ports. Methanol is then transferred into a methanol-to-hydrogen reconversion facility. After reconversion, the hydrogen is stored as liquid hydrogen before being regasified to be directly serviced at the interconnection point at the Ports. This alternative assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.

Figure 21: Methanol Shipping Map and Components

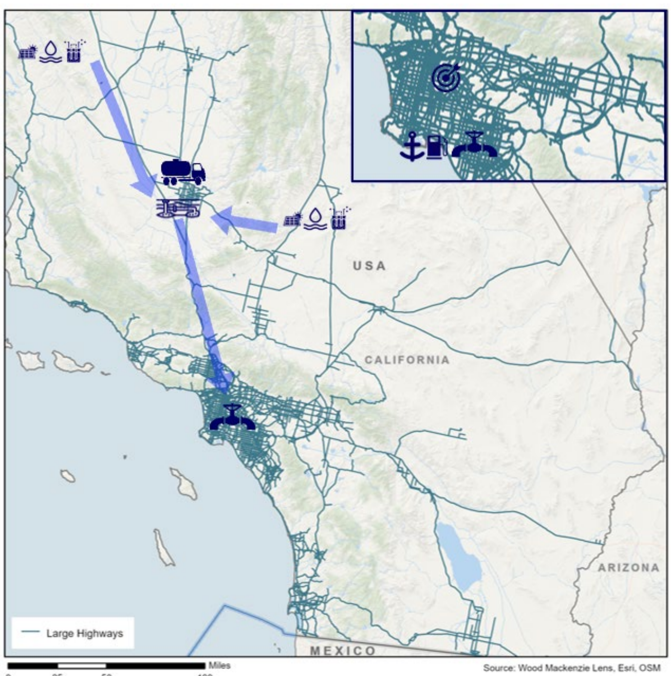


Component	Key Infrastructure for Scenario 7
Production	39.9 GW solar plants
	1.5 mtpa from Northern California 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	Above-ground storage at ports in a 135 acres, 610 liquid sphere farm
Transmission	1 to 2 ships making 60 round trips a year to transport 1.5 mtpa from Northern California to L.A. ports
Delivery	~80-mile delivery pipeline

7.2.2.4. Gaseous Hydrogen Trucking

Hydrogen produced at the identified production locations is compressed and loaded at production facilities, then transported to end users via compressed hydrogen trucks. Each truck can transport up to 1 tonne of hydrogen per load, while loading bays can dispatch 5 trucks per day. Assumes vehicle stock turnover from diesel trucks to fuel cell electric drive trains in the 2030s to meet California's decarbonization goals. Trucks would use existing highways, following corridors similar to conceptual pipeline routes. This alternative assumes the use of underground storage (such as depleted oil fields), which would be connected via gaseous trucks. This alternative assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports.

Figure 22: Gaseous Hydrogen Trucking Map and Components



Component	Key Infrastructure for Scenario 7
Production	39.9 GW solar plants
	0.75 mtpa from SJV and 0.75 mtpa from Lancaster 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	Underground storage in depleted oil fields
Transmission	12,700 trucks and 3,400 loading bays required to serve maximum day capacity on a year, 127 vehicle-miles[134] for Scenario 7
Delivery	~80-mile delivery pipeline

[134] 127 vehicle-miles in this context equates to a 127-mile chain of contiguous gaseous hydrogen trucks in a single day.

7.2.2.5. Localized Hub[135]

A dedicated clean renewable hydrogen pipeline system located within the L.A. Basin with production and end use in close proximity that could support connections between the state's decarbonization projects within the ARCHES portfolio. This Localized Hub connects clean renewable hydrogen producers to multiple end users in the hard-to-electrify sectors via open access, common carrier pipeline infrastructure. The Localized Hub within the L.A. Basin is fed only by in-basin production and/or production in close proximity to multiple in-basin end users and storage. The considerations for the Localized Hub are split into two areas: A) Geography and B) Value Chain Evaluation.

A. **Geography** The L.A. Basin is a geographically defined area in Southern California; a coastal plain bounded by the Pacific Ocean to the west and surrounded by mountains and hills, including the Santa Monica Mountains to the north, the San Gabriel mountains to the northeast, and the Santa Ana Mountains to the southeast. The L.A. Basin encompasses the central part of Los Angeles County, including portions of the San Fernando Valley, and extends into parts of Orange, Riverside and San Bernardino counties.
B. **Value Chain Evaluation** The Localized Hub is characterized and analyzed to account for the hydrogen value chain to support local production, transport, storage, and delivery systems and the associate feasibility considerations.
    a. **Production**: The Localized Hub considers production within and in close proximity to multiple in-basin end users and storage and will assess production prospects within a 40-mile radius expanding outward from the area of concentrated demand near the Ports of Los Angeles and Long Beach. This approach is designed to encompass the L.A. Basin and those outskirt areas close to multiple in-basin end users and storage. See Figure 23 below for a map depicting L.A. Basin and close proximity boundary.
    Hydrogen production will include two primary feedstocks: solar energy and biomass. Regarding solar energy, the assessment will include feasibility of constructing

[135] "SoCalGas shall study a localized hydrogen hub solution, under the specifications required to be eligible for federal funding provided through the Infrastructure Investment and Jobs Act, as part of Phase One." (D.22-12-055, p. 74.).

independent solar power sites. Biomass will focus on the utilization of woody biomass and the conversion of municipal waste.

b. **Target Demand Sectors**: The Hub aims to address the dedicated demand from multiple sectors within the L.A. Basin contributing to a reduction in GHG emissions and will seek to meet the diverse capacity and unique consumption patterns of the different end use applications. These sectors include the following:
    i. Power Generation: Supporting the transition to cleaner energy solutions for public and private power generation facilities.
    ii. Industrial & Commercial Manufacturing: Catering to the energy and feedstock demands of factories, processing plants, and other industrial and manufacturing end users.
    iii. Mobility: Especially focusing on heavy-duty trucking operations emerging from ports, which require substantial low-carbon and zero-carbon energy solutions. The Localized Hub's close proximity to ports provides efficient fueling solutions for these heavy-duty transport systems.

c. **Pipeline Transmission**: Within the Hub, hydrogen would be transported through a series of high-pressure trunk transmission pipelines to connect production and offtake and facilitate potential connections to third-party storage facilities. The pipeline system would be designed for safe, efficient, and rapid transport of hydrogen from production sources located within or close to multiple delivery points within the L.A. Basin. For purposes of the feasibility stage, the Hub is assumed to include approximately 80 miles of transmission pipeline within the 40-mile radius for production and storage assessed for the Hub. This mileage corresponds to the miles of transmission pipeline that would be located within the L.A. Basin for the Angeles Link preferred routes, as this provides a baseline for potential transmission needs for the Hub to connect well-known demand centers near the Ports of Los Angeles and Long Beach. The total mileage of pipelines for the Hub may be greater, as land constraints may result in more distributed production facilities and additional pipeline mileage needed for transmission and distribution to meet the production, demand, and storage needs.

d. **Storage**: In the intermittence of synchronized production and demand, reserve hydrogen would be stored above-ground. Storage solutions within a 40-mile radius expanding from the area of concentrated demand near the Ports of Los Angeles and Long Beach are considered with regard to their high-level suitability and technology readiness level.

Figure 23: Localized Hub Area Map

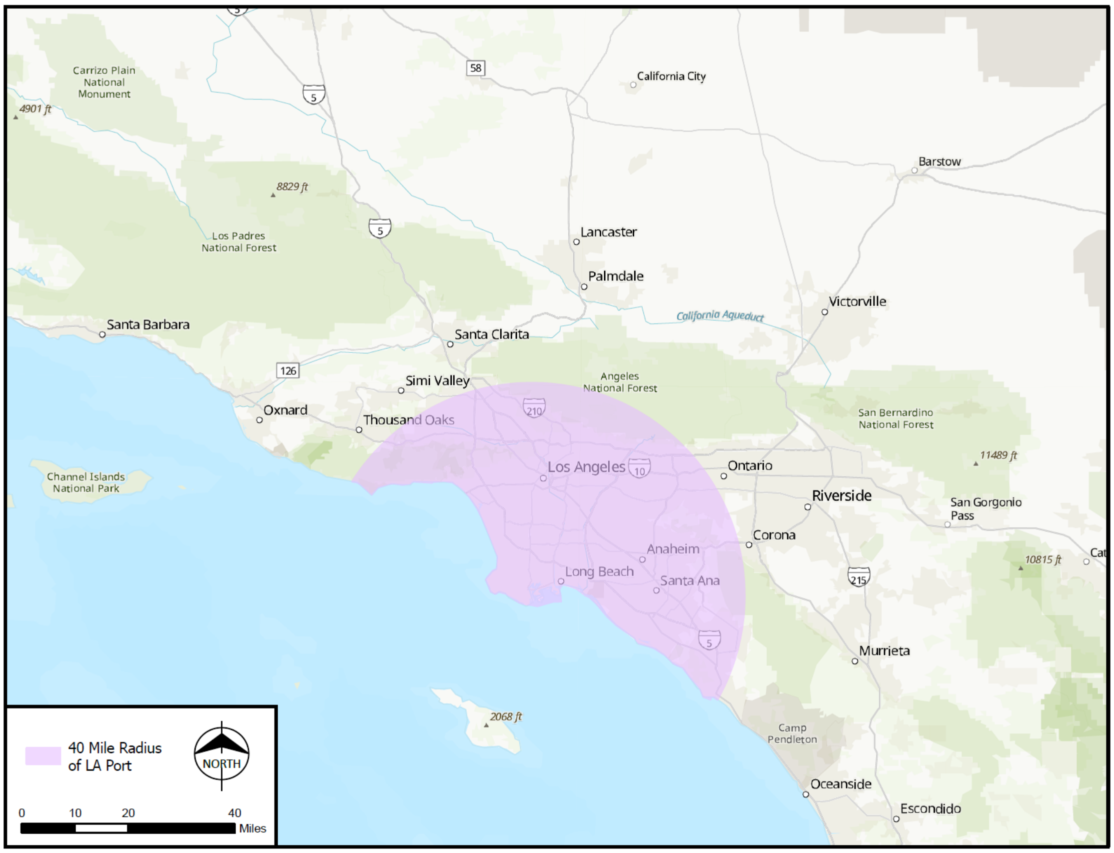
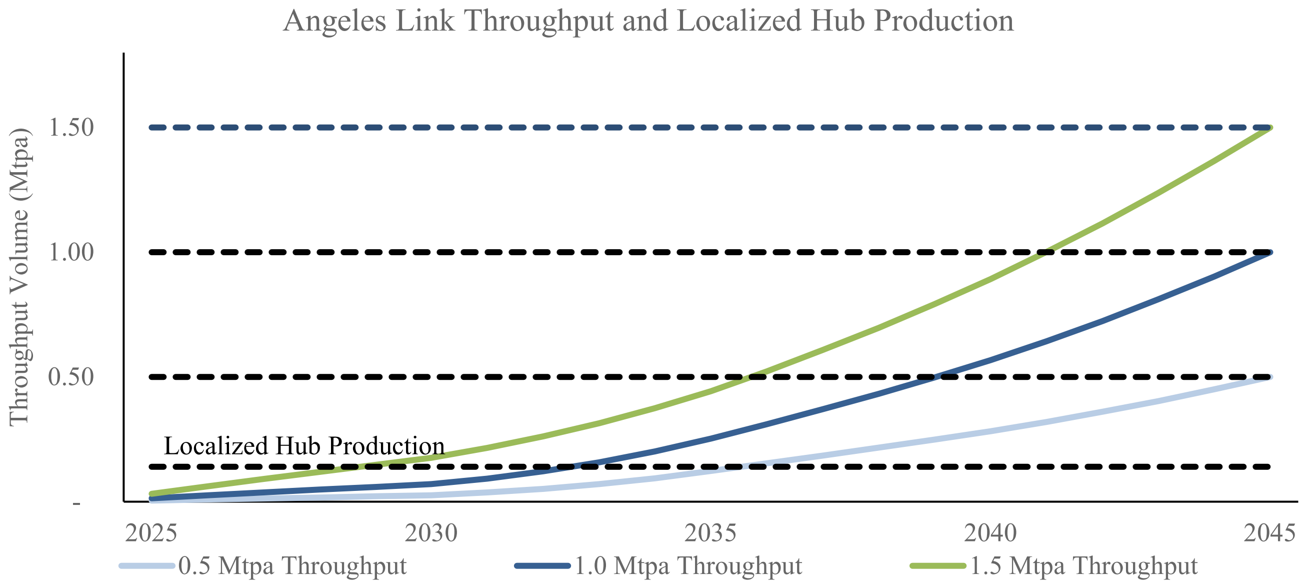


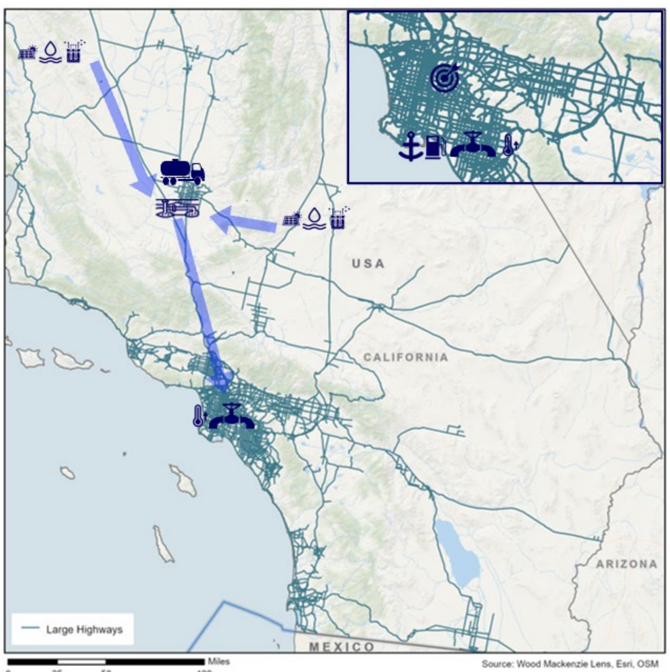
Figure 24: Angeles Link Throughput and Localized Hub Production



7.2.2.6. Liquid Hydrogen Trucking

Hydrogen produced at the defined production locations is liquefied and loaded at each production site to liquid hydrogen trucks and then transported to end users. Each truck can transport up to 4 tonnes (metric tons) of hydrogen per load, while loading bays can dispatch 4 trucks per day. Assumes vehicle stock turnover from diesel trucks to fuel cell electric drive trains in the 2030s to meet California's decarbonization goals. Trucks would use existing highways, following corridors similar to conceptual pipeline routes. This alternative assumes the use of underground storage (such as depleted oil fields), which would be connected via liquid trucks. Assumes a distribution pipeline is developed in the L.A. Basin with interconnection to end users, including the Ports of Los Angeles and Long Beach (Ports).

Figure 25: Liquid Hydrogen Trucking Map and Components

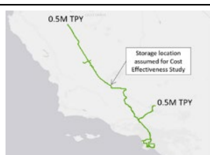
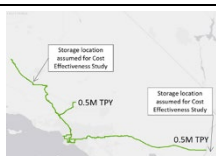
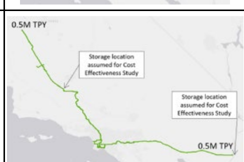
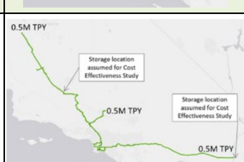


Component	Key Infrastructure for Scenario 7
Production	39.9 GW solar plants
	0.75 mtpa from SJV and 0.75 mtpa from Lancaster 133 | 200 MW electrolyzers equivalent to 26.6 GW capacity 14.7 MGD water feedstock
Storage	Underground storage in depleted oil fields
Transmission	3,200 trucks and 700 loading bays required to serve maximum day capacity, 32 vehicle-miles on the road for scenario 7[136]
Delivery	~80-mile delivery pipeline

[136] 32 vehicle-miles in this context equates to a 32-mile chain of contiguous liquid hydrogen trucks in a single day.

7.2.3. Angeles Link & Delivery Alternatives Scenarios Configurations

Table 17: Angeles Link Production Scenarios vs. Hydrogen Delivery Alternatives

Scenario	Map	Demand	Delivery Methods	Production (mtpa)					Storage		
				SJV	Lancaster	Blythe	Northern California	In-Basin	Depleted Oil Fields	Salt Caverns	Above-Ground
1		0.5 mtpa	Angeles Link	0.5					✓		
			Trucking	0.5					✓		
			Shipping				0.5				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
2		0.5 mtpa	Angeles Link		0.5				✓		
			Trucking		0.5				✓		
			Shipping				0.5				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
3		0.5 mtpa	Angeles Link			0.5				✓	
			Trucking			0.5				✓	
			Shipping				0.5				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
4		1.0 mtpa	Angeles Link	0.5	0.5				✓		
			Trucking	0.5	0.5				✓		
			Shipping				1.0				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
5		1.0 mtpa	Angeles Link		0.5	0.5			✓	✓	
			Trucking		0.5	0.5			✓	✓	
			Shipping				1.0				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
6		1.0 mtpa	Angeles Link	0.5		0.5			✓	✓	
			Trucking	0.5		0.5			✓	✓	
			Shipping				1.0				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
7		1.5 mtpa	Angeles Link	0.75	0.75				✓		
			Trucking	0.75	0.75				✓		
			Shipping				1.5				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓
8		1.5 mtpa	Angeles Link	0.5	0.5	0.5			✓	✓	
			Trucking	0.5	0.5	0.5			✓	✓	
			Shipping				1.5				✓
			In-Basin Prod.	N/A							✓
			Localized Hub					0.14			✓

7.3. Assumptions Tables

7.3.1. Hydrogen Delivery Alternatives

7.3.1.1. Production

Table 18 below is shows a summary of the Production Cost Input Assumptions and their sources. Hydrogen production costs were assumed to be the same for all delivery alternatives, except the localized hub.[137] Extended cost input assumptions for hydrogen production can be found in the Production Study.

Table 18: Production Cost Input Assumptions

Parameter	Unit	Angeles Link & Delivery Alternatives (Except Localized Hub)	Source
Power Production Facility			
Solar facility CAPEX	\$/kW, real 2024	\$1,125	Production Study
Solar facility OPEX	\$/kW/year, real 2024	\$20	
Solar capacity factor	%	26.4%	
Hydrogen Production Facility			
Electrolyzer CAPEX	\$/kW, real 2024	\$2,707	Production Study
Electrolyzer OPEX	% of CAPEX	0.7%	
Stack replacement CAPEX	\$/kW, real 2024	\$509	
Stack replacement frequency	years	10	
Electrolyzer plant efficiency	kWh/kgH_2	60	
Hydrogen production technology	N/A	PEM Electrolyzer	
Input for LCOH for Scenario 7			
Discounted total costs (CAPEX, OPEX, and PTC)	US\$ MM, real 2024	\$74,809	N/A

[137] While costs were the same, each delivery alternative had different losses (per Appendix 7.3.1.7) along the value chain, which means the LCOH would show slight variations.

7.3.1.2. Transmission

7.3.1.2.1. Angeles Link System

Additional cost information can be found in the Pipeline Design Study.

Table 19 below shows a summary of the Angeles Link transmission cost input assumptions for Scenario 7. Additional cost information can be found in the Pipeline Design Study.

Table 19: Angeles Link System Cost Input Assumptions for Scenario 7

Parameter	Unit	Value	Source
Inputs from Design Study			
Pipeline CAPEX	US$ MM, real 2024	$7,471.06	Design Study
Compressor Station CAPEX	US$ MM, real 2024	$3,673.23	
Pipeline O&M	% of pipeline CAPEX	1%	
Compressor fixed O&M	% of compressor CAPEX	1%	
Compressor power requirement	kWh/kgH_2	0.36 - 0.40	
Key infrastructure requirements			
Total transmission pipeline length[138]	mi	310	Design Study
Total compressor power capacity	hp	100,000	
Number of compressor stations	#	2	
Input for LCOH			
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$11,243	N/A

Note: In line with the treatment for all delivery alternatives, the pipeline CAPEX was adjusted to meet the estimated maximum daily throughput requirements from production facilities to either storage or delivery in Central and Southern California and estimated maximum daily draw from storage to Central and Southern California. The key infrastructure requirements and inputs for LCOH correspond to the Scenario 7 for 1.5 Mtpa.

[138] Excludes the approximately 80-mile delivery system.

7.3.1.2.2. Trucking

The table below shows the gaseous trucking and liquid trucking transmission cost input assumptions.

Table 20: Trucking Cost Input Assumptions

Parameter	Unit	Gaseous Hydrogen Trucking	Liquid Hydrogen Trucking[139]	Source
Terminal				
Loading bay capacity	tpd	4	20	National Petroleum Council[140]
CAPEX per bay	US$ MM, real 2024	$11.09	$105.94	
Fixed O&M loading bay	% of CAPEX	5.0%	3.3%	
Electricity consumption	kWh/kgH_2	3	10	
Delivery Trucks				
CAPEX, trucks, and trailers	US$ MM, real 2024	$1.18	$1.41	National Petroleum Council
Fixed O&M	US$ per truck, real 2024	$70,627	$188,340	
Variable O&M (non-fuel)	US$/mi, real 2024	$1.61	$1.29	
Variable O&M (fuel)	MJ/mi	20		
Truck speed (average)	Mph	35		
Loading / unloading time	hours	1.45		
On-trailer capacity	Ton H_2	1	4	
Truck lifecycle	years	12		
Key Infrastructure Requirements for Scenario 7				
Loading terminals required	#	3,428	686	N/A
Trucks required	#	12,760	3,190	
Total miles per year	Million mi	618	155	
Input for LCOH for Scenario 7				
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$108,380	$119,242	N/A

Note: The number of loading bays and trucks required were estimated to meet the maximum daily requirement of hydrogen over a one-year period. The total miles traveled per year were optimized for each scenario, so that the distance traveled from supply, to and from storage, and into demand sites was minimized. The parameters for Opex such as electricity consumption and O&M were estimated for the average utilization. For liquid hydrogen trucking, liquefaction costs were considered as part of transmission. Regasification costs were accounted for as a separate line item, please refer to Table 23 for additional information on liquid hydrogen trucking regasification.

[139] Additional Liquid Hydrogen Trucking assumptions can be found in Table 23.
[140] National Petroleum Council. Harnessing Hydrogen: A Key Element of the U.S. Energy Future.

7.3.1.2.3. Shipping

The table below shows a summary of the shipping cost input assumptions used to estimate shipping cost.

Table 21: Shipping Cost Input Assumptions

<table>
<tr><th>Parameter</th><th>Unit</th><th>Liquid Hydrogen Shipping [141]</th><th>Methanol Shipping [142]</th><th>Source</th></tr>
<tr><td colspan="5">CAPEX and OPEX</td></tr>
<tr><td>CAPEX per vessel</td><td>US$ MM, Real 2024</td><td>$51.02</td><td>$217.77</td><td rowspan="3">Wood Mackenzie Hydrogen Midstream Model</td></tr>
<tr><td>Fixed O&M</td><td>% of CAPEX</td><td>4.45%</td><td>4.45%</td></tr>
<tr><td>Port charge (loading / unloading)</td><td>US$ MM, Real 2024</td><td>$0.03</td><td>$0.20</td></tr>
<tr><td colspan="5">Operational Parameters</td></tr>
<tr><td>Ship size</td><td>Cubic meters</td><td>10,000</td><td>174,000</td><td rowspan="7">Wood Mackenzie Hydrogen Midstream Model</td></tr>
<tr><td>Ship speed</td><td>knots</td><td colspan="2">19</td></tr>
<tr><td>On hire days</td><td>days</td><td colspan="2">350</td></tr>
<tr><td>Fill rate</td><td>%</td><td colspan="2">98.5%</td></tr>
<tr><td>Port days loading / unloading</td><td>days</td><td>0.75</td><td>1.50</td></tr>
<tr><td>Port fuel consumption</td><td>tpd</td><td>4</td><td>25</td></tr>
<tr><td>At sea fuel consumption (laden and ballast)</td><td>tpd</td><td>64</td><td>210</td></tr>
<tr><td colspan="5">Key Infrastructure Requirements for Scenario 7</td></tr>
<tr><td>Vessels required</td><td>#</td><td>27</td><td>1</td><td rowspan="2">N/A</td></tr>
<tr><td>Round trips required</td><td>#</td><td>2,125</td><td>57</td></tr>
<tr><td colspan="5">Input for LCOH for Scenario 7</td></tr>
<tr><td>Discounted total costs (CAPEX and OPEX)</td><td>US$ MM, real 2024</td><td>$4,712</td><td>$616</td><td>N/A</td></tr>
</table>

Note: The number of ships was estimated to meet the maximum daily requirement over a one-year period.

141 Additional Liquid Hydrogen Shipping assumptions can be found in Table 23.
142 Additional Methanol Shipping assumptions can be found in Table 24.

7.3.1.2.4. Power T&D

The table below shows a summary of the shipping cost input assumptions used to estimate shipping cost.

Table 22: Power T&D Cost Input Assumptions

Parameter	Unit	Value	Source
CAPEX and Operational Parameters			
CAPEX single circuit transmission line	US$ MM, real 2024	$5.95	Southern California Edison[143]
CAPEX double circuit transmission line	US$ MM, real 2024	$10.78	
CAPEX Substation	US$ MM, real 2024	$47.68	
CAPEX transformer (500/230 kV, 1,120 MVA)	US$ MM, real 2024	$37.84	
CAPEX transformer (230/66 kV, 280 MVA)	US$ MM, real 2024	$8.78	
Operational Parameters			
Transmission line voltage	kV	500	CAISO and PG&E operating metrics for typical 500 kV equipment
Power factor	Factor	0.80	
Transformer capacity (1,120 MVA)	GW	0.896	
Transformer capacity (280 MVA)	GW	0.224	
Transmission line losses	% per 100 mi	1.30%	
Transformer losses	%	2.00%	
Power Carrying Capacity (500 kV AC transmission lines)			
From 0 to 50 miles	MW	3,040	U.S. Department of Energy[144]
From 51 to 100 miles	MW	2,080	
From 101 to 200 miles	MW	1,320	
From 201 to 300 miles	MW	1,010	
From 301 to 400 miles	MW	810	
From 401 to 500 miles	MW	680	
From 501 to 600 miles	MW	600	
Key Infrastructure Requirements for Scenario 7			
New transmission lines miles	Miles	400	N/A
New transmission lines[145]	#	21	
Substations required	#	4	
Transformers	#	308	
Input for LCOH for Scenario 7			
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$28,889	N/A

Note: The number of transmission lines was estimated to meet the maximum daily requirement over a one-year period.

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[143] Southern California Edison, 2022 SCE Generator Interconnection Unit Cost Guide.
[144] U.S. Department of Energy, National Transmission Needs Study.
[145] The number of lines required depends on the power generation capacity and carrying capacity for the distance from supply to sub-station. 26.6 GW is the electricity need for the electrolysis process. Total generation also accounts for transmission losses of 1.8 GW for the scope configuration of Scenario 7 of the in-basin hydrogen production with power T&D alternative. Total installed solar capacity is estimated at 43 GW in the Production Study to account for intra-day availability. The assumption in Scenario 7 is fourteen single circuit (seven double circuit) lines from SJV to the L.A. Basin (assumes a 300-mile distance), and seven single circuit (three double circuit plus one single circuit) lines from SJV to the L.A. Basin (assumes a 100-miles distance) across a 400 mile transmission corridor.

7.3.1.3. Liquefaction and Regasification

The table below shows a summary of the cost input assumptions for liquefaction for liquid hydrogen shipping and regasification for liquid hydrogen shipping and liquid hydrogen trucking.

Table 23: Liquefaction and Regasification Cost Input Assumptions

Parameter	Unit	Liquid Hydrogen Shipping	Liquid Hydrogen Trucking	Source
Liquefaction				
CAPEX per liquefaction train	US$ MM, real 2024	$125	Inc. in transmission costs as part of loading bays	Wood Mackenzie Hydrogen Midstream Model
Fixed O&M	% of CAPEX	1.0%		
Liquefaction power consumption	kWh/kgH_2	10		
Liquefaction train size	tpd	30		
Number of liquefaction trains required	#	136		
Regasification				
CAPEX regasification terminal	US$/Nm^3/h, real 2024	$956.38	$956.38	Wood Mackenzie Hydrogen Midstream Model
CAPEX liquid storage tanks	US$/m^3, real 2024	$4,251	$4,251	
Fixed O&M	% of CAPEX	1.24%	1.24%	
Key Infrastructure Requirements for Scenario 7				
Total power consumption	GWh/year	539	539	N/A
Input for LCOH for scenario 7				
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$23,235	$2,965	N/A

Note: Liquefaction and regasification infrastructure was estimated to meet the maximum daily requirements over a one-year period. For liquid hydrogen trucking, the liquefaction costs were assumed to be part of transmission since loading bays include liquefaction and loading costs.

7.3.1.4. Methanol Production and Hydrogen Reconversion

The table below shows a summary of the cost input assumptions for methanol production and hydrogen reconversion for methanol shipping.

Table 24: Methanol Production and Hydrogen Reconversion Cost Input Assumptions

Parameter	Unit	Methanol Production	Hydrogen Reconversion	Source
Methanol Production and Hydrogen Reconversion				
CAPEX methanol plant	US$ MM/tpd H_2, real 2024	\$2.49	\$6.08	Wood Mackenzie Hydrogen Midstream Model
CAPEX methanol storage	US\$/m^3, real 2024	\$311.06		
Fixed O&M	% of CAPEX	1.24%	0.90%	
Key Infrastructure Requirements for Scenario 7				
Total power consumption	GWh/year	3,349		N/A
Input for LCOH for Scenario 7				
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	\$50,294		N/A

Note: Methanol production and hydrogen reconversion infrastructure were estimated to meet the maximum daily requirements over a one-year period.

7.3.1.5. Distribution Pipeline

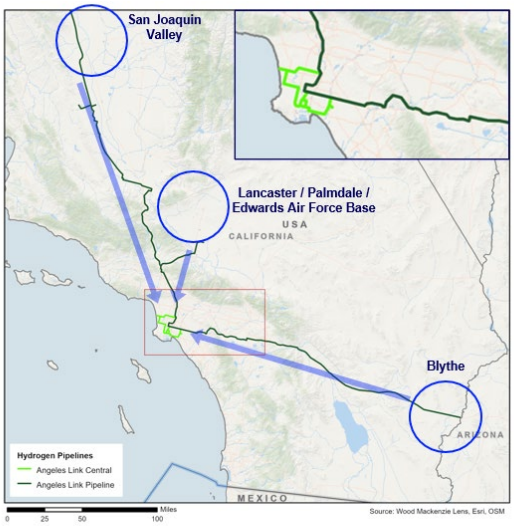
The table below shows the distribution pipeline cost input assumptions for Angeles Link. The same costs were assumed for all delivery alternatives.

Table 25: Distribution Cost Input Assumptions

Parameter	Unit	Value for all Delivery Alternatives	Source
Inputs from Design Study			
Distribution pipeline CAPEX	US$ MM, real 2024	$1,436.60	Design Study
Distribution pipeline O&M	% of pipeline CAPEX	1%	
Key infrastructure requirements for Scenario 7			
Distribution pipeline length	mi	80	Design Study
Input for LCOH for Scenario 7			
Discounted total costs (CAPEX and OPEX)	US$ MM, real 2024	$1,419	N/A

Note: Distribution costs were modeled to match the delivery costs of the Angeles Link Central per Figure 26 below for each delivery alternative.

Figure 26: Illustrative Map of Angeles Link and Delivery Alternatives Key Locations[146]



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[146] The systems would be designed to serve demand along their routes.

7.3.1.6. Storage

For additional storage assumptions, refer to Appendix 7.5.1. For the localized hub alternative, the above-ground storage requirements were assumed to be the same on a $/KgH$_2$ and the total costs were adjusted to match the localized hub production volumes.

7.3.1.7. Losses by Delivery Alternative

Table 26: Hydrogen Losses by Delivery Alternative and Value Chain Segment

(%)	Angeles Link	Liquid Hydrogen Shipping	In-Basin Production w/Power T&D	Methanol Shipping	Gaseous Hydrogen Trucking	Localized Hub	Liquid Hydrogen Trucking	Source
Regasification or Hydrogen Reconversion	N/A	0.00%	0.00%	0.07%	N/A	N/A	0.00%	Wood Mackenzie Midstream Model
Liquefaction or Methanol Production	N/A	0.00%	N/A	0.00%	N/A	N/A	N/A	
Transmission	1.26%	0.32%	N/A	0.00%	N/A	N/A	N/A	
	N/A	N/A	N/A	N/A	2.00%	N/A	5.00%[147][148]	National Petroleum Council[148]
Storage	N/A	3.38%	3.37%	3.37%	N/A	N/A	N/A	
	0.02%	N/A	N/A	N/A	0.02%	N/A	0.02%	Angeles Link Hydrogen Leakage Study[149]
Delivery	0.57%	0.59%	0.58%	0.58%	0.58%	N/A	0.59%	
Production	2.00%	2.00%	2.00%	2.00%	2.00%	N/A	2.00%	
Total	**3.85%**	**6.29%**	**5.95%**	**6.02%**	**4.60%**	**N/A**	**7.61%**	

Assumptions on hydrogen losses across each delivery alternative's value chain segments determine the final volume delivered.

[147] Includes liquefaction losses.
[148] National Petroleum Council. (2024). Harnessing Hydrogen: A Key Element of the U.S. Energy Future
[149] Angeles Link Hydrogen Leakage Study.

7.3.2. Non-Hydrogen Alternatives Assumption Tables

7.3.2.1. Mobility

Table 27: Techno-Economic Assumptions: Class 8 Sleeper Cab (2030)

Assumptions	Low	Base	High	Sources
Fuel economy (MPGe)				
FCEV		13		Argonne National Laboratory
BEV		23		
Tank range (mi):				
FCEV		420		Representative vehicle specifications from OEMs
BEV		275		
Purchase cost ($k):				
FCEV	228		456	Argonne National Laboratory
BEV	255		510	
Labor cost ($/mi)		0.94		
Dwell cost ($/hr)		89		
Refueling rate (mins):				
FCEV	10		30	Argonne National Laboratory
BEV	20		60	Argonne National Laboratory and TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/kg)	4.51	6.01	7.51	Includes the LCOH from Angeles Link of $5.29 + $1.85 distribution cost + $0.70 dispensing cost - $2.04 LCFS credit pass through
BEV ($/kWh)	0.31	0.43	0.60	Assuming a SCE EV charging tariff and applying a retail projection along with a retail markup. Assuming LCFS credits are included in the retail markup

Table 28: Techno-Economic Assumptions: Transit Bus (2030)

Assumptions	Low	Base	High	Sources
Fuel economy (MPGe)				
FCEV	17			Argonne National Laboratory
BEV	29			
Tank range (mi):				
FCEV	370			Representative vehicle specifications from OEMs
BEV	300			
Purchase cost ($k):				
FCEV	311		623	Argonne National Laboratory
BEV				
Labor cost ($/mi)	0.94			
Dwell cost ($/hr)	89			
Refueling rate (mins):				
FCEV	10		30	Argonne National Laboratory
BEV	20		60	Argonne National Laboratory and TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/kg)	4.51	6.01	7.51	Includes the LCOH from Angeles Link of $5.29 + $1.85 distribution cost + $0.70 dispensing cost - $2.04 LCFS credit pass through
BEV ($/kWh)	0.31	0.43	0.60	Assuming a SCE EV charging tariff and applying a retail projection along with a retail markup. Assuming LCFS credits are included in the retail markup

Table 29: Techno-Economic Assumptions: Class 8 Drayage (2030)

Assumptions	Low	Base	High	Sources
Fuel economy (MPGe)				
FCEV	12			Argonne National Laboratory
BEV	22			
Tank range (mi):				
FCEV	450			Representative vehicle specifications from OEMs
BEV	200			
Purchase cost ($k):				
FCEV	185		371	Argonne National Laboratory
BEV	166		331	
Labor cost ($/mi)	0.94			
Dwell cost ($/hr)	89			
Refueling rate (mins):				
FCEV	10		30	Argonne National Laboratory
BEV	20		60	Argonne National Laboratory and TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/kg)	4.51	6.01	7.51	Includes the LCOH from Angeles Link of $5.29 + $1.85 distribution cost + $0.70 dispensing cost - $2.04 LCFS credit pass through
BEV ($/kWh)	0.34	0.35	0.49	Assuming a SCE EV charging tariff and applying a retail projection along with a retail markup. Assuming LCFS credits are included in the retail markup

Table 30: Techno-Economic Assumptions: Class 8 Day Cab (2030)

Assumptions	Low	Base	High	Sources
Fuel economy (MPGe)				
FCEV	13			Argonne National Laboratory
BEV	23			
Tank range (mi):				
FCEV	500			Representative vehicle specifications from OEMs
BEV	300			
Purchase cost ($k):				
FCEV	201		402	Argonne National Laboratory
BEV	187		373	
Labor cost ($/mi)	0.94			
Dwell cost ($/hr)	89			
Refueling rate (mins):				
FCEV	10		30	Argonne National Laboratory
BEV	20		60	Argonne National Laboratory and TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/kg)	4.51	6.01	7.51	Includes the LCOH from Angeles Link of $5.29 + $1.85 distribution cost + $0.70 dispensing cost - $2.04 LCFS credit pass through
BEV ($/kWh)	0.34	0.35	0.49	Assuming a SCE EV charging tariff and applying a retail projection along with a retail markup. Assuming LCFS credits are included in the retail markup

7.3.2.2. Power

Table 31: Techno-Economic Assumptions: Hydrogen Combustion Turbine Retrofit (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		500		Wood Mackenzie LCOE Model
Net capacity factor (%)				
Baseload	60%	50%	40%	Wood Mackenzie LCOE Model
Peaking	11%	10%	9%	
Capex ($/kW)				
Baseload – retrofit	156	208	260	NPC Study
Peaking – retrofit	156	208	260	
Fixed O&M ($/kW-yr)				
Baseload	70	78	86	Wood Mackenzie LCOE Model
Peaking	51	56	62	
Variable O&M ($/MWh)				
Baseload	3	4	4	Wood Mackenzie LCOE Model
Peaking	11	13	14	
Fuel cost				
Angeles Link LCOH ($/kg)	4.13	5.50	6.88	Cost Effectiveness Study LCOH
Energy equivalent ($/MMBtu$_e$)	31	41	51	Conversion of LCOH to energy equivalent in MMBtu

Table 32: Techno-Economic Assumptions: Gas Turbine with CCS Retrofit (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		500		Wood Mackenzie LCOE Model
Net capacity factor (%)	60%	50%	40%	
Capex ($/kW)				
Baseload - retrofit	1,243	1,775	2,308	Wood Mackenzie LCOE Model
Fixed O&M ($/kW-year)	64	91	119	Wood Mackenzie LCOE Model
Variable O&M ($/MWh)	4	5	7	
Fuel cost				
Delivered fuel cost ($/MMBtu$_e$)	3.6	4.5	5.4	Forecast of delivered gas price at SoCalGas Citygate
T&D adder ($/MMBtu)		3.5		Wood Mackenzie LCOE Model
CO_2 transport and sequestration ($/ton)	92		368	Wood Mackenzie CCS Model (California-specific)
45Q credit value ($/MWh)		18		Forecast reflecting outlook on current policy

Table 33: Techno-Economic Assumptions: Battery Storage Facility - 12 hour (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		400		Based on Moss Landing, largest operating facility in California
Discharge duration (Hours)		12		Wood Mackenzie LCOE Model
Roundtrip efficiency (%)		86%		
Net capacity factor (%)	12%	10%	8%	Follows from duration and assumes 30+ cycles per year
Capex ($/kW)	2,526	3,367	4,209	Wood Mackenzie LCOE Model
Fixed O&M ($/kW-yr)	95	119	143	
Variable O&M ($/MWh)	10	13	16	
Charging cost ($/MWh)	44	59	71	Forecast of average annual wholesale price forecast for CAISO SP15
ITC (%)		30%		Forecast reflecting outlook on current policy

7.3.2.3. Cogeneration

Table 34: Techno-Economic Assumptions: Hydrogen Turbine Retrofit (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		30		Wood Mackenzie LCOE Model
Net capacity factor (%)	69	58	46	
Capex ($/kW)	266	380	494	
Fixed O&M ($/kW-year)	105	117	129	
Variable O&M ($/MWh)	8	9	9	
Fuel cost				
Angeles Link LCOH ($/kg)	4.13	5.50	6.88	Angles Link LCOH
Energy equivalent ($/MMBtu$_e$)	31	41	51	Conversion of LCOH to energy equivalent in MMBtu

Table 35: Techno-Economic Assumptions: Gas Turbine with CCS Retrofit (2030)

Assumptions	Low	Base	High	Sources
Facility size (MW)		30		Wood Mackenzie LCOE Model
Net capacity factor (%)	69	58	46	
Capex ($/kW)	2,100	3,000	3,900	
Fixed O&M ($/kW-year)	124	137	151	
Variable O&M ($/MWh)	10	11	13	
Fuel cost				
Delivered fuel cost ($/MMBtu$_e$)	3.6	4.5	5.4	Forecast of delivered gas price at SoCal Citygate
T&D adder ($/MMBtu)		3.5		Wood Mackenzie North America Gas Model
CO_2 transport and sequestration ($/ton)	92		368	Wood Mackenzie CCS Model (California-specific)
45Q credit value ($/MWh)		18		Forecast reflecting outlook on current policy

7.3.2.4. Food & Beverage

Table 36: Techno-Economic Assumptions: Food & Beverage Alternatives (2030)

Assumptions	Low	Base	High	Sources
Hydrogen				
Delivered fuel cost ($/kg)	4.1	5.5	6.9	Angeles Link LCOH
Electricity				
Retail cost ($/MWh)	180	225	270	SCE Industrial Service Tariffs and Third-Party Forecasts
Green premium - CA REC prices ($/MWh)	25			Wood Mackenzie Long Term Power Model

7.3.2.5. Cement

Table 37: Techno-Economic Assumptions: Cement Alternatives (2030)

Assumptions	Low	Base	High	Sources
Hydrogen				
Delivered fuel cost ($/kg)	4.1	5.5	6.9	Angeles Link LCOH
Gas + CCS				
Delivered fuel cost ($/MMBtu)	3.6	4.5	5.4	Wood Mackenzie North America Gas and CCS Models
T&D adder ($/MMBtu)	3.5			
CO2 transport and sequestration cost ($/ton)	92		368	
Electricity				
Retail cost ($/MWh)	180	225	270	SCE Industrial Service Tariffs and Third-Party Forecasts
CA REC prices ($/MWh)	25			Wood Mackenzie Long Term Power Model

7.3.2.6. Refineries

Table 38: Techno-Economic Assumptions: Refinery Alternatives (2030)

Assumptions	Low	Base	High	Sources
Clean Renewable Hydrogen				
Delivered feedstock cost ($/kg)	4.1	5.5	6.9	Angeles Link LCOH
Hydrogen Abated with CCS				
Delivered feedstock cost ($/kg)	1.8		3.5	Wood Mackenzie LCOH Model
CO_2 transport and sequestration cost ($/ton)	92		368	Wood Mackenzie CCS Models (California-specific)

7.4. Results Tables

7.4.1. LCOH by Alternative Matrix

Table 39 below includes a summary of the LCOH ($/KgH₂) estimated for all Angeles Link and delivery alternatives for all scenarios. For additional information on scenarios, refer to Appendix 7.2.2.6.

Table 39: Cost Effectiveness of Angeles Link vs. Alternatives for All Scenarios

LCOH ($/KgH$_2$)	Angeles Link	Liquid Hydrogen Shipping	In-Basin Production w/Power T&D	Methanol Shipping	Gaseous Hydrogen Trucking	Localized Hub	Liquid Hydrogen Trucking
Scenario 1	$6.20	$8.14	$9.79	$9.14	$11.84	$12.03	$12.62
Scenario 2	$5.95	$8.11	$7.62	$9.11	$11.51	$12.03	$12.55
Scenario 3	$7.35	$8.11	$9.02	$9.11	$15.03	$12.03	$14.38
Scenario 4	$5.53	$8.33	$8.95	$9.34	$11.78	$12.03	$13.06
Scenario 5	$6.38	$8.32	$8.58	$9.33	$14.10	$12.03	$14.29
Scenario 6	$6.52	$8.33	$9.67	$9.34	$14.16	$12.03	$14.28
Scenario 7	$5.50	$8.21	$8.73	$9.20	$11.40	$12.03	$12.62
Scenario 8	$6.22	$8.20	$8.94	$9.19	$12.63	$12.03	$13.28

7.4.2. Delivery Alternatives Costs

Table 40 below includes a summary of the estimated cost by value chain segment for Angeles Link (per the Production Study and Design Study) and delivery alternatives. For additional information on the inputs for these costs, refer to Appendix 7.3.1.

Table 40: Discounted Costs by Delivery Alternatives and Value Chain Segment for Scenario 7

LCOH (US$MM)	Angeles Link	Liquid Hydrogen Shipping	In-Basin Production w/Power T&D	Methanol Shipping	Gaseous Hydrogen Trucking	Localized Hub	Liquid Hydrogen Trucking
Delivery	1,419	1,419	1,419	1,419	1,419	1,419	1,419
Regasification or Hydrogen Reconversion	0	3,013	0	25,541	0	0	2,965
Storage	4,603	26,920	37,880	37,880	4,603	3,536	4,603
Transmission	11,243	4,712	28,889	616	108,380	0	119,242
Liquefaction or Methanol Production	0	23,235	0	10,414	0	0	0
Production	74,809	74,809	74,809	74,809	74,809	15,207	74,809
Total	**92,074**	**134,108**	**142,997**	**150,679**	**189,211**	**20,162**	**203,038**

7.5. Key Considerations

7.5.1. Storage

Clean hydrogen production and above-ground and underground storage are not currently proposed as part of Angeles Link. As Angeles Link is further designed and, in alignment with the development of system requirements, the role of storage to support regional hydrogen producers and end users should be considered. During the early phases of the demand growth, above-ground storage (such as liquid hydrogen storage vessels) and, when pipelines are available, line pack, could potentially support the required storage needs for regional hydrogen producers and end users.[150]

The Alternatives Study and Cost Effectiveness Study were guided by the Production Study storage analysis, which evaluated conceptual hydrogen storage and associated storage injection and withdrawal flow trends enabling the technoeconomic assessments across various types of storage.[151] In line with these assumptions, the Alternatives Study and Cost Effectiveness Study included storage as a component of the Angeles Link pipeline system and Hydrogen Delivery Alternatives to support energy system reliability needs at a high level. This simplified approach did not consider how market demand for hydrogen and its storage will scale over time and how interim storage solutions may be utilized in the early phases of demand growth, as described above.

To analyze delivery alternatives in the Cost Effectiveness Study, two primary storage methods were considered for cost effectiveness evaluation: above-ground storage and underground storage, with underground storage further divided into salt caverns and depleted oil/gas reservoirs. Storage methods for each delivery alternative are location-bound, meaning the type of storage assumed depends on availability (or lack thereof) near the delivery alternative's value chain.

For third-party production regions, such as SJV and Lancaster, there is potential to use depleted oil/gas reservoirs near Bakersfield. To accommodate production near the L.A. Basin, specifically in-basin production, it was assumed it would be necessary to construct above-ground storage facilities. This is due to the unavailability of underground storage options within the L.A. Basin. In the context of above-

[150] The Angeles Link pipeline system could also offer storage options through linepack. See Production Study, section 8.2 for additional information.
[151] See Production Study for additional information on storage.

ground storage, liquid storage vessels were chosen due to their higher energy density. When comparing above-ground compressed gaseous storage facilities to above-ground liquid hydrogen storage, the latter has the potential to address land limitations that may arise when implementing large-scale above-ground in-basin storage solutions.

The techno-economic parameters for cost-effectiveness evaluation are identified in Table 41. These parameters are based on external literature and have been prorated to meet the storage capacity and throughput requirements of the Angeles Link System (Scenario 7) and other delivery alternatives. [152,153]

[152] Some storage cost components were taken and adjusted to reflect Angeles Link capacity and throughput requirements from: Chen, F., Ma, Z., Nasrabadi, H., Chen, B., Mehana, M. Z. S., & Van Wijk, J. (2024). Capacity Assessment and Cost Analysis of Geologic Storage of Hydrogen: A Case Study in Intermountain-West Region USA. Los Alamos National Laboratory and Texas A&M University.
[153] National Petroleum Council. (2024). Harnessing Hydrogen: A Key Element of the U.S. Energy Future.

Table 41: Storage Cost Parameters for Scenario 7[154]

Parameter	Unit	Underground		Above-ground Liquid Storage	Source
		Depleted Oil Field	Salt Cavern		
Total storage capacity	tH_2	425,000	425,000	425,000	Angeles Link Production Study
Individual storage tank capacity	tH_2 or m^3	N/A	N/A	~700 tH_2 or 10,000 m^3	National Petroleum Council[155, 156]
Total storage volumes (throughput)	tH_2	~968,000	~968,000	~968,000	Angeles Link Production Study
Pressure	Bar	235	235	<5	Underground: Chen et. al.[157] Above-ground: National Petroleum Council
Fixed O&M	% of CAPEX	1.0%	1.0%	2.0%	
Power demand	kWh/kgH_2	2.2	2.2	10.0	
Storage CAPEX (including cushion gas)	US$MM	$3,052	$12,328	$17,756	
Compressor/Liquefier CAPEX	US$MM	$917	$917	$10,257	
Total CAPEX	**US$MM**	**$3,968**	**$13,244**	**$28,013**	

[154] See Table 5 in the Design Study, Configuration A, single run scenario; also referred to as Scenario 7 in table 4 in the same study.
[155] National Petroleum Council. Harnessing Hydrogen: A Key Element of the U.S. Energy Future.
[156] The capacities assumed for above-ground storage were reported as commercially available by developers. Larger storage vessels are in development: a large-scale LH_2 tank, with a capacity ranging from 20,000 to 100,000 cubic meters, is both feasible and cost competitive at import and export terminals. See: Shell-Led Consortium Selected by DOE to Demonstrate Feasibility of Large-Scale Liquid Hydrogen Storage.
[157] Capacity Assessment and Cost Analysis of Geologic Storage of Hydrogen: A Case Study in Intermountain-West Region USA. Chen, et al, 2024.

7.5.2. Considerations for T&D with In-Basin Production Transmission Technology

The T&D with in-basin hydrogen production alternative assumed a new build electric transmission and distribution system (500kV AC transmission system) in addition to the associated electric system appurtenances (such as step-up/step-down electric transformer substations required at the point of offtake of electricity and at the point of receipt) and associated high voltage transmission losses. In response to stakeholder feedback during the PAG meeting in June 2024, considerations of the potential to transmit electricity via High Voltage Direct Current (HVDC) system instead of High Voltage Alternating Current (HVAC) transmission system were added to this analysis.

Several factors may influence the decision to move energy as molecules (hydrogen) or electrons (electricity), including regionality constraints, siting/land-use restrictions, environmental implications, energy throughput considerations, techno-economics, and the transport distance. According to the LA100 Study, "resources that use renewably produced and storable fuels…[are] a key element of maintaining reliability at least cost given…challenges in upgrading existing or developing new transmission."[158] The HVDC systems will require additional electric conversion investments to convert electricity from direct current (DC) to alternating current (AC) at the point of receipt to utilize the energy for hydrogen production at scale.

California has roughly 33,000 miles of electrical lines, with PG&E operating 57%, Southern California Edison (SCE) 16%, San Diego Gas & Electric (SDG&E) 6%, local utilities 18%, and government 3%.[159] HVAC systems account for the majority of the high voltage transmission network in California.[160] The only HVDC transmission line in the California high voltage transmission system is the undersea Trans Bay Cable in San Francisco Bay, which went into service in late 2010.[161] The high-voltage TransWest Express Transmission Project (to meet the energy demands in the western United States) is currently under development and includes 732 miles of high-voltage transmission infrastructure divided into two systems: a 3,000 MW HVDC segment with terminals near Sinclair,

[158] Chapter 6. Renewable Energy Investments and Operations (nrel.gov) (p. 3).
[159] California Power Lines, Hydroelectric Power, and Natural Gas (uci.edu).
[160] Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generating Stations (SONGS): Environmental Feasibility Analysis.
[161] Ibid.

Wyoming, and Delta, Utah, and a 1,500 MW HVAC segment from the Utah terminal to southern Nevada.[162]

For the purpose of this study, the T&D with in-basin hydrogen production alternative focused on the 500kV AC transmission system as the default technology of choice to enable system and operational compatibility with the California's predominantly HVAC electric grid system to help meet the reliability and resiliency requirements.

[162] Ibid.