This supplemental databook is complementary to the Angeles Link High-Level Economic Analysis and Cost Effectiveness Study prepared by Wood Mackenzie.

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Financial Assumptions

Parameter	Unit	Value	Source
Federal tax rate	%	21.0%	Internal Revenue Service
State tax rate	%	8.8%	State of California
Inflation rate	%	2.0%	Wood Mackenzie
Period of valuation	years	25	Industry Standard
Discount date	dd/mm/yyyy	1/1/2024	SoCalGas
WACC	%	7.67%	SoCalGas WACC from CPUC Resolution E-5306
Depreciation timeframe	years	20	Assumption
Depreciation method	na	Straight Line	
Owners Cost	% of CAPEX	10.0%	
Days in year	Days	365	

Tax Credits

Parameter	Unit	Value	Source
Tax Credits			
H2 production tax credit	US$/kg-H2, Real 2024	$3.00	Inflation Reduction Act
H2 production tax credit last start year	year	2033	
H2 production tax credit years	year	10	
Power ITC	%	30.0%	
Power PTC	US$ per kWh, Real 2024	$0.03	
ITC/PTC last start year	year	2036	
Power PTC years	years	10	
Power Tax credits (ITC/PTC) phase out percentages			
2023-2033	year	100.00%	Inflation Reduction Act
2034-2035	year	75.00%	
2035-2036	year	50.00%	
2036+	year	0.00%	

CAPEX Schedule

Parameter	Unit	Value	Source
CAPEX Schedule			
2025	Start year -5	0.00%	Assumption
2026	Start year -4	0.00%	
2027	Start year -3	0.00%	
2028	Start year -2	75.00%	
2029	Start year -1	25.00%	

Distances Assumptions

Parameter	Unit	Value	Source
Pipeline Route Distances			
San Joaquin Valley Route to Delivery Point	miles	250	Design Study
Palmdale / Lancaster Route to Delivery Point	miles	100	
Blythe Route to Delivery Point	miles	235	
Trucking Routes Distances			
San Joaquin Valley to San Joaquin Valley Depleted Oil Fields Storage	miles	140	Estimated from Design Study Inputs
Palmdale / Lancaster to San Joaquin Valley Depleted Oil Fields Storage	miles	90	
Blythe to Out of State Salt Cavern Storage	miles	100	
San Joaquin Valley Depleted Oil Fields Storage to Distribution Delivery Point	miles	140	
Out of State Salt Cavern Storage to Distribution Delivery Point	miles	335	
Shipping Routes Distances			
Northern California	nm (vessel)	450	Assumption
In-Basin Production with Power T&D Routes Distances			
San Joaquin Valley	miles	300	Estimated from Design Study Inputs
Palmdale / Lancaster	miles	100	
Blythe	miles	235	
Delivery Pipeline Length			
Delivery/Distribution Line	miles	79	Design Study

Upstream Assumptions for Angeles Link & Delivery Alternatives (Except Localized Hub)

Parameter	Unit	Value	Source
Power Feedstock			
H2 power demand	kWh / kg-H2	60	Production Study
Solar capacity factor	%	26.40%	
Water Feedstock			
Water usage intensity	kg H2O per kg H2	14	Water Study
Water cost	US$/m3	$2.51	
Hydrogen Production			
Electrolyzer building block	MW	200	Production Study
Stack lifetime (hours)	hours	34,087	
Stack replacement CAPEX	US$/kW	$508.82	
Electrolyzer unit cost	US$/kW	$2,707.38	
Fixed Electrolyzer O&M (% / yr of capex)	%	0.74%	
Production losses	%	2.00%	Air Studies
Degradation factor	%	0.75%	Wood Mackenzie
Electrolyzer owners cost	%	10.00%	Assumption
Online factor	days	365	

Liquefaction or Methanol Conversion

Parameter	Unit	Value	Source
Hydrogen Liquefaction			
Liquefaction CAPEX per train	US$ MM	$124.96	Wood Mackenzie Hydrogen Midstream Model
H2 liquefaction train size	tpd	30	
Liquefaction fixed O&M (% / yr of capex)	%	1.00%	
Power consumption	kWh/kgH2	10	National Petroleum Council
Hydrogen conversion losses	%	0.00%	Assumption
Methanol conversion			
Methanol plant CAPEX	US$ MM/tpd hydrogen	$2.49	Wood Mackenzie Hydrogen Midstream Model
Methanol conversion losses	%	0.00%	
Methanol storage time	days	14	
Fixed O&M (% / yr of capex)	%	1.24%	
Methanol storage CAPEX	$/m3	$311.06	

Storage

Parameter	Unit	Value	Source
Gaseous Storage			
Total Storage Capacity for Scenario 7	tH2	425,000	Production Study
Total Storage Throughput for Scenario 7	tH2	968,000	
Turnover frequency, nameplate capacity basis for Scenario 7	1/year	2.28	
Storage Capacity per Unit (gaseous)	tH2	5,000	National Petroleum Council
Pressure (gaseous storage)	bar	150	
Tank CAPEX (cH2 Storage)	$/kgH2	$17.88	
Compressor CAPEX (cH2 Storage)	$/kgH2-year	$0.78	
Fixed O&M (cH2 Storage)	% CAPEX	2.00%	
cH2 Storage power demand	kWh/kgH2	2	
cH2 Storage boil-off rate	% per day	0.00%	
Liquid Storage			
Total Storage Capacity for Scenario 7	tH2	425,000	Production Study
Total Storage Throughput for Scenario 7	tH2	968,000	
Turnover frequency, nameplate capacity basis for Scenario 7	1/year	2.28	
Storage Capacity per unit (Liquid)	tH2	700	National Petroleum Council
Pressure (liquid storage)	bar	<5	
Tank Capex (LH2 Storage)	$/kgH2	$41.72	
Liquefier CAPEX (LH2 Storage)	$/kgH2-year	$10.58	
Fixed O&M (LH2 Storage)	% CAPEX	2.00%	
LH2 Storage power demand	kWh/kgH2	10	
LH2 Storage boil-off rate	% per day	0.03%	
Underground Storage: Depleted Oil Fields			
Total Storage Capacity for Scenario 7	tH2	425,000	Production Study
Total Storage Throughput for Scenario 7	tH2	968,000	
Turnover frequency, nameplate capacity basis for Scenario 7	1/year	2.28	
Pressure (gaseous storage)	bar	235	
DOF CAPEX (cH2 Storage)	$/kgH2	$2.43	
Fixed O&M (cH2 Storage)	% CAPEX	1.00%	
Compressor CAPEX (cH2 Storage)	$/kgH2-year	$0.95	Capacity Assessment and Cost Analysis of Geologic Storage of Hydrogen: A Case Study in Intermountain-West Region
cH2 Storage power demand	kWh/kgH2	2.20	
Cushion gas percentage from capacity	%	100.00%	
cH2 Storage boil-off rate	% per day	0.00%	National Petroleum Council
Underground Storage: Salt Caverns			
Total Storage Capacity for Scenario 7	tH2	0	Production Study
Total Storage Throughput for Scenario 7	tH2	N/A	
Turnover frequency, nameplate capacity basis for Scenario 7	1/year	N/A	
Pressure (gaseous storage)	bar	235	
Salt Cavern CAPEX (cH2 Storage) for Scenario 7	$/kgH2	N/A	
Fixed O&M (cH2 Storage)	% CAPEX	1.00%	
Compressor CAPEX (cH2 Storage)	$/kgH2-year	$0.95	Capacity Assessment and Cost Analysis of Geologic Storage of Hydrogen: A Case Study in Intermountain-West Region
cH2 Storage power demand	kWh/kgH2	2.20	
Cushion gas percentage from capacity	%	100.00%	
cH2 Storage boil-off rate	% per day	0.00%	National Petroleum Council

Trucking

Parameter	Unit	Value	Source
Trucks (General)			
Truck speed	Mph	35	Assumption
Shift time	hours per day	8.8	
Truck lifetime	years	12.0	National Petroleum Council
Shifts per day	#	1.0	
Terminal bay lifetime (Trucks)	years	25.0	
Truck fuel consumption	MJ/mi	20.0	
Truck fuel consumption	kgH2/Mi	0.167	
Truck fuel consumption	gal of Diesel/Mi	0.147	
Fuel cost	$/MJ	0.037	
Gaseous Trucks and Terminal			
Loading bay capacity (gaseous)	tpd	4.0	National Petroleum Council
Capex per bay (gaseous)	US$ MM	$11.09	
Fixed O&M gaseous terminal	% of bay CAPEX	5.00%	
Gaseous terminal power demand	kWh/kgH2	3.0	
Gaseous truck CAPEX	US$ MM	$1.18	
Fixed O&M gaseous truck	US$/truck-shift	$70,627.79	
Non Fuel gaseous truck O&M variable	US$/mi	$1.61	
Gaseous truck capacity	kgH2/round trip	1,000	
Gaseous truck loading/unloading losses	%	0.00%	
Gaseous truck unloading losses	%	0.00%	
Gaseous truck boil-off losses	%	2.00%	
Gaseous loading time	hours	1.45	Assumption
Gaseous unloading time	hours	1.45	
Liquid Trucks and Terminal			
Loading bay capacity (liquid)	tpd	20.0	National Petroleum Council
Capex per bay (liquid)	US$ MM	$105.94	
Fixed O&M liquid terminal	% of bay CAPEX	3.30%	
Liquid terminal power demand	kWh/kgH2	10.0	
Liquid truck CAPEX	US$ MM	$1.41	
Fixed O&M liquid truck	US$/truck	$188,340.78	
Non Fuel liquid truck O&M variable	US$/mi	$1.29	
Liquid truck capacity	kgH2/round trip	4,000	
Liquid truck loading losses	%	0.00%	
Liquid truck unloading losses	%	0.00%	
Liquid truck boil-off losses	%	5.00%	
Liquid loading time	hours	1.45	Assumption
Liquid unloading time	hours	1.45	

Shipping

Parameter	Unit	Value	Source
Shipping (General)			
Fuel price (VLSFO)	$/tonne	$595.00	Wood Mackenzie North America Product Markets
On hire days	days	350.00	Wood Mackenzie Hydrogen Midstream Model
Fill Rate	%	98.50%	
Shipping Liquid H2			
Vessel size	m3	10,000	Wood Mackenzie Hydrogen Midstream Model
Vessel speed	knots	19.00	
LH2 boil-off rate	% per day	0.23%	
Port days loading	days	0.75	
Port days discharge	days	0.75	
Port fuel consumption	tpd	4.00	
At sea fuel consumption laden	tpd	45.00	
At sea fuel consumption ballast	tpd	19.00	
Port charge loading/unloading	US$ MM	$0.03	
Vessel liquid H2 CAPEX	US$ MM	$51.02	
Vessel liquid H2 OPEX	US$ MM	$2.27	
Shipping Methanol			
Vessel size	m3	174,000	Wood Mackenzie Hydrogen Midstream Model
Vessel speed	knots	19.00	
Methanol boil-off rate	% per day	0.00%	
Port days loading	days	1.50	
Port days discharge	days	1.50	
Port fuel consumption	tpd	25.00	
At sea fuel consumption laden	tpd	105.00	
At sea fuel consumption ballast	tpd	105.00	
Port charge loading/unloading	US$ MM	$0.20	
Vessel liquid methanol CAPEX	US$ MM	$217.77	
Vessel liquid methanol OPEX	US$ MM	$4.13	

H2 Regasification and Methanol Reconversion

Parameter	Unit	Value	Source
H2 Regasification			
Regasifier CAPEX	$/Nm3/h	$956.38	Wood Mackenzie Hydrogen Midstream Model
Regas power consumption	kW/Nm3/h	0.05	
Fixed O&M H2 regas (% / yr of capex)	%	1.24%	
Hydrogen regas losses	%	0.00%	
Liquid hydrogen storage CAPEX	$/m3	$4,251.11	
Hydrogen storage time	days	4.00	
Methanol Reconversion			
Methanol reformer CAPEX	US$ MM/tpd hydrogen	$6.08	Wood Mackenzie Hydrogen Midstream Model
Methanol boil off	%/day	0.01%	
Methanol storage CAPEX	$/m3	$311.06	
Methanol storage time	days	14.00	
Methanol reconversion losses	%	0.00%	
Fixed O&M (% / yr of capex)	%	0.90%	
LP hydrogen storage CAPEX	$/kgH2	$680.63	
Hydrogen storage time	days	0.00	

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Production by Scenario

Parameter	Unit		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Comments
Total Production	Mtpa		0.5	0.5	0.5	1	1	1	1.5	1.5	Total project size (Mtpa)

Volume Allocation by Corridor

Parameter	From	To	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Comments
Allocation of volumes by Production Location											
Production %	From	San Joaquin Valley	100.0%			50.0%		50.0%	50.0%	33.3%	Split from production locations
Production %	From	Palmdale / Lancaster		100.0%		50.0%	50.0%		50.0%	33.3%	Split from production locations
Production %	From	Blythe			100.0%		50.0%	50.0%		33.3%	Split from production locations
% of Average Supply Delivered to Storage vs. LA Basin											
Average	To LA Basin	San Joaquin Valley	36.8%			0.0%		34.3%	0.0%	0.0%	Assumption % of avg prod to destination
Average	To LA Basin	Palmdale / Lancaster		36.8%		68.6%	34.3%		70.9%	70.9%	Assumption % of avg prod to destination
Average	To LA Basin	Blythe			36.8%		34.3%	34.3%		35.5%	Assumption % of avg prod to destination
Average	To Storage	San Joaquin Valley to SJV	63.2%	0.0%	0.0%	100.0%	0.0%	65.7%	100.0%	100.0%	Assumption % of avg prod to destination
Average	To Storage	Palmdale / Lancaster to SJV	0.0%	63.2%	0.0%	31.4%	65.7%	0.0%	29.1%	29.1%	Assumption % of avg prod to destination
Average	To Storage	Blythe to OOS	0.0%	0.0%	63.2%	0.0%	65.7%	65.7%	0.0%	64.5%	Assumption % of avg prod to destination
Average	In/out Storage	SJV Depleted Oil Field Storage to Port	63.2%	63.2%	0.0%	131.4%	65.7%	65.7%	129.1%	129.1%	Total avg flow into storage
Average	In/out Storage	OOS Salt Cavern Storage to Port	0.0%	0.0%	63.2%	0.0%	65.7%	65.7%	0.0%	64.5%	Total avg flow into storage
% of Maximum Supply Delivered to Storage vs. LA Basin											
Max	To LA Basin	San Joaquin Valley	43.3%			0.0%		34.2%	0.0%	0.0%	Assumption % of max prod to destination
Max	To LA Basin	Palmdale / Lancaster		43.3%		68.4%	34.2%		76.7%	76.7%	Assumption % of max prod to destination
Max	To LA Basin	Blythe			43.3%		34.2%	34.2%		38.4%	Assumption % of max prod to destination
Max	To Storage	San Joaquin Valley to SJV	56.7%	0.0%	0.0%	100.0%	0.0%	65.8%	100.0%	100.0%	Assumption % of max prod to destination
Max	To Storage	Palmdale / Lancaster to SJV	0.0%	56.7%	0.0%	31.6%	65.8%	0.0%	23.3%	23.3%	Assumption % of max prod to destination
Max	To Storage	Blythe to OOS	0.0%	0.0%	56.7%	0.0%	65.8%	65.8%	0.0%	61.6%	Assumption % of max prod to destination
Max	In/out Storage	SJV Depleted Oil Field Storage to Port	56.7%	56.7%	0.0%	131.6%	65.8%	65.8%	123.3%	123.3%	Total max flow into storage
Max	In/out Storage	OOS Salt Cavern Storage to Port	0.0%	0.0%	56.7%	0.0%	65.8%	65.8%	0.0%	61.6%	Total max flow into storage
Ratio of Average to Maximum Flows by Corridor											
Ratio avg to max	Production	San Joaquin Valley	1.44			1.44		1.44	1.44	1.44	Max flow prod / avg flow prod
Ratio avg to max	Production	Palmdale / Lancaster		1.44		1.44	1.44		1.44	1.44	Max flow prod / avg flow prod
Ratio avg to max	Production	Blythe			1.44		1.44	1.44		1.44	Max flow prod / avg flow prod
Ratio avg to max	To Storage	SJV Depleted Oil Field Storage to Port	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.77	Max flow into storage / avg flow prod
Ratio avg to max	To Storage	OOS Salt Cavern Storage to Port	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.89	Max flow into storage / avg flow prod
Ratio avg to max	To LA Basin	SJV Depleted Oil Field Storage to Port	1.77	1.77		4.26	2.13	2.13	3.88	4.11	Max flow out / avg flow prod
Ratio avg to max	To LA Basin	OOS Salt Cavern Storage to Port			1.77		2.13	2.13		1.71	Max flow out / avg flow prod

Storage Cost Assumptions

Cost Assumption	Parameter	Unit	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Source
Above Ground Storage Assumptions											
AG storage	Total capacity	ktpa	125.00	125.00	125.00	300.00	300.00	300.00	425.00	425.00	Production Study
AG storage	Throughput	ktpa	316.00	316.00	316.00	657.00	657.00	657.00	968.00	968.00	
AG storage	Turnover frequency, nameplate capacity basis	times	2.53	2.53	2.53	2.19	2.19	2.19	2.28	2.28	
Depleted Oil Fields Storage Assumptions											
DOF Storage	Total CAPEX	US$MM	$342.59	$342.59		$646.65	$411.11	$411.11	$1,032.97	$646.65	See Storage Appendix
DOF Storage	Total capacity	ktpa	125.00	125.00		300.00	150.00	150.00	425.00	300.00	
DOF Storage	Throughput	ktpa	316.00	316.00		657.00	329.00	329.00	968.00	657.00	
DOF Storage	Turnover frequency, nameplate capacity basis	times	2.53	2.53	0.00	2.19	2.19	2.19	2.28	2.19	
Salt Cavern Storage Assumptions											
Salt Cavern Storage	Total CAPEX	US$MM			2863.58		3436.29	3436.29		2863.58	See Storage Appendix
Salt Cavern Storage	Total capacity	ktpa			125.00		150.00	150.00		125.00	
Salt Cavern Storage	Throughput	ktpa			316.00		329.00	329.00		316.00	
Salt Cavern Storage	Turnover frequency, nameplate capacity basis	times	0.00	0.00	2.53	0.00	2.19	2.19	0.00	2.53	

Pipeline CAPEX

Parameter	Parameter	Unit	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Source
Angeles Link Transmission											
Path 1 - SJV (Nodes 1, 2, 3, 4, 6)	Total CAPEX	US$MM	$2,707.85	$1,198.25		$1,787.77	$735.10	$1,783.85	$3,080.89	$2,694.59	Estimated from Design Study to meet Max. throughput
Path 2 - Lancaster (Nodes 8, 9, 10)	Total CAPEX	US$MM		$753.45		$567.48	$566.75		$834.19	$751.78	
Path 3 - SJV & Lancaster (Node 13)	Total CAPEX	US$MM	$2,888.35	$2,905.16		$2,597.83	$2,249.28	$2,590.47	$3,555.97	$3,437.66	
Path 4 - Blythe (Nodes 29, 36)	Total CAPEX	US$MM			$6,890.96		$5,567.95	$5,709.67		$7,099.57	
Path 5 - Blythe to OOS SC	Total CAPEX	US$MM			$3,076.32		$2,496.84	$2,560.39		$3,169.45	
Path 6	Total CAPEX	US$MM									
Path 7	Total CAPEX	US$MM									
Path 8	Total CAPEX	US$MM									
Distribution for all Delivery Alternatives											
Distribution & Delivery	Total CAPEX	US$MM	$1,297.53	$1,122.36	$1,122.58	$1,295.55	$1,264.40	$1,294.08	$1,436.60	$1,334.26	Design Study

Compressor Cost Assumptions

Parameter	Parameter	Unit	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Source
Compressor CAPEX											
San Joaquin Valley	Total CAPEX	US$MM	$1,212.17			$1,212.17		$1,212.17	$1,836.61	$1,212.17	Estimated from Design Study to meet Max. throughput
Palmdale / Lancaster	Total CAPEX	US$MM		$1,212.17		$1,212.17	$1,212.17		$1,836.61	$1,212.17	
Blythe	Total CAPEX	US$MM			$1,212.17		$1,212.17	$1,212.17		$1,212.17	
Pipeline and Compressor Fixed OPEX											
Pipeline	Fixed O&M	% of CAPEX	1%	1%	1%	1%	1%	1%	1%	1%	Design Study
Compressor	Fixed O&M	% of CAPEX	1%	1%	1%	1%	1%	1%	1%	1%	
Compressor Efficiency											
San Joaquin Valley	Power consumption	kWh/kg H2	0.38			0.34		0.20	0.40	0.36	Design Study
Palmdale / Lancaster	Power consumption	kWh/kg H2		0.26		0.18	0.26		0.36	0.21	
Blythe	Power consumption	kWh/kg H2			0.21		0.24	0.17		0.28	
Compressor power drive	Electric / Hydrogen		Electric	Electric	Electric	Electric	Electric	Electric	Electric	Electric	

Pipeline distances

Parameter	Parameter	Unit	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Source
Path 1 - SJV (Nodes 1, 2, 3, 4, 6)	Total Distance	Miles	276	157		235	157	276	227	235	Design Study
Path 2 - Lancaster (Nodes 8, 9, 10)	Total Distance	Miles		37		37	37		41	37	
Path 3 - SJV & Lancaster (Node 13)	Total Distance	Miles		41		41	41		42	41	
Path 4 - Blythe (Nodes 29, 36)	Total Distance	Miles			224		223	223		224	
Path 5 - Blythe to OOS SC	Total Distance	Miles			100		100	100		100	
Distribution & Delivery	Total Distance	Miles	79	79	79	79	79	79	80	79	

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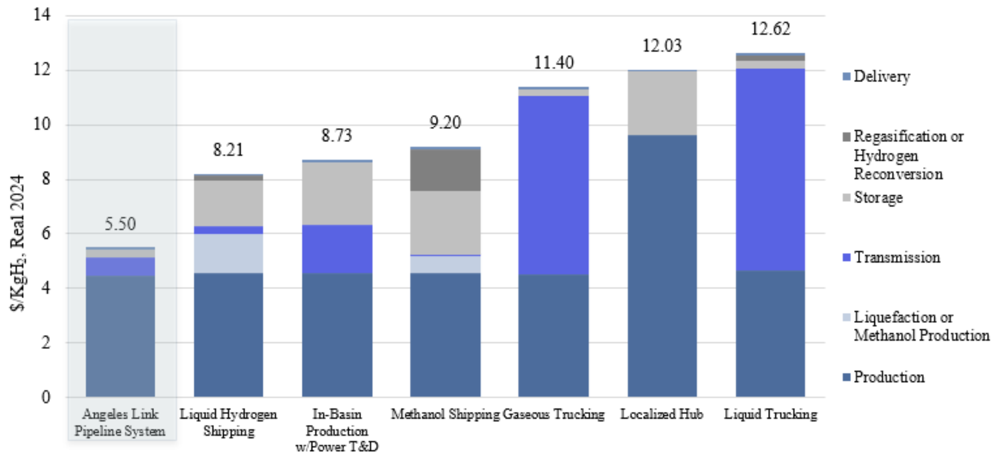

Notes: Reflects costs from Scenario 7 for 1.5 Mtpa. Production is assumed to begin in 2030 to take advantage of tax incentives, including Production Tax Credits (PTC) for hydrogen (45V)[66] and power (45Y),[67] which provide up to $3 per kgH_2 and $0.028 per kWh for ten years. Storage assumptions were based on proximity to production sites, and the geographic footprint under consideration for storage in the Production Study.[68] 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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Mobility Input Assumptions

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Class 8 Sleeper Cab

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)		$89		
Refueling rate (mins):				
FCEV	10		30	Argonne National Laboratory
BEV	20		60	Argonne National Laboratory and Wood Mackenzie TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/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

Transit Bus

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	$311		$623	
Labor cost ($/mi)		$0.94		
Dwell cost ($/hr)		$89		
Refueling rate (mins):				
FCEV	10		30	Argonne National Laboratory
BEV	20		60	Argonne National Laboratory and Wood Mackenzie TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/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

x

Class 8 Drayage

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)		$89		
Refueling rate (mins):				
FCEV	10		30	Argonne National Laboratory
BEV	20		60	Argonne National Laboratory and Wood Mackenzie TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/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

Class 8 Day Cab

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)		$89		
Refueling rate (mins):				
FCEV	10		30	Argonne National Laboratory
BEV	20		60	Argonne National Laboratory and Wood Mackenzie TCO Model
Fuel cost (net of applicable LCFS)				
FCEV ($/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

Wood Mackenzie

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Power Input Assumptions

x

Hydrogen Combustion Turbine Retrofit

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

x

Battery Storage Facility - 12 hour

Assumptions	Low	Base	High	Sources
Facility size (MW)		400		Based on Moss Landing, largest operating facility in Califiornia
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

x

Gas Turbine with CCS Retrofit

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

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Cogeneration Input Assumptions

x

Hydrogen Turbine Retrofit

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

x

Gas Turbine with CCS Retrofit

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

Food & Beverage Input Assumptions

x **Food & Beverage Alternatives**

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

Cement Input Assumptions

x **Cement Alternatives**

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

Refineries Input Assumptions

x **Refinery Alternatives**

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)

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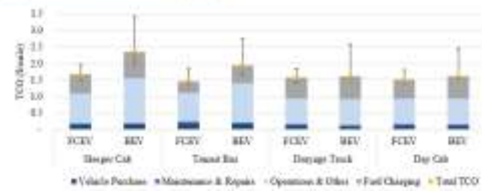
Note: The output tables shown below were used to generate the charts in the Cost Effectiveness Report. A screenshot of the corresponding chart has been provided.

Mobility

x **TCO Cost Effectiveness - Mobility**

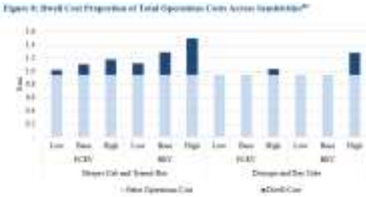
	Sleeper Cab		Transit Bus		Drayage Truck		Day Cab	
	FCEV	BEV	FCEV	BEV	FCEV	BEV	FCEV	BEV
Vehicle Purchase	$0.15	$0.17	$0.19	$0.19	$0.12	$0.11	$0.13	$0.12
Maintenance & Repairs	$0.04	$0.02	$0.05	$0.02	$0.04	$0.02	$0.04	$0.02
Operations & Other	$0.90	$1.36	$0.88	$1.20	$0.77	$0.79	$0.76	$0.80
Fuel/Charging	$0.59	$0.81	$0.35	$0.53	$0.64	$0.70	$0.59	$0.67
TCO - Base	$1.68	$2.36	$1.47	$1.94	$1.57	$1.62	$1.52	$1.61
TCO - High	$1.99	$3.43	$1.86	$2.76	$1.84	$2.59	$1.80	$2.46
TCO - Low	$1.47	$1.94	$1.33	$1.64	$1.43	$1.52	$1.39	$1.52

Figure 7: Cost Effectiveness: Mobility (2030)



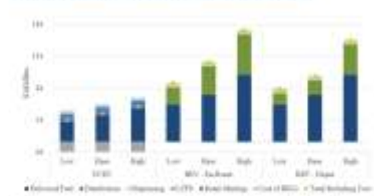
x **Dwell Cost Proportion of Operations Cost**

	Sleeper Cab and Transit Bus						Drayage and Day Cabs					
	FCEV			BEV			FCEV			BEV		
	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
Other Operations Cost	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94
Dwell Cost	$0.08	$0.16	$0.24	$0.18	$0.35	$0.56	$0.00	$0.00	$0.09	$0.00	$0.00	$0.34



x **Fuel/Charging Cost Breakdown**

	FCEV			BEV - En-Route			BEV - Depot		
	Low	Base	High	Low	Base	High	Low	Base	High
Delivered Fuel	$30.69	$40.92	$51.15	$58.31	$73.84	$104.89	$58.31	$73.84	$104.89
Distribution	$13.76	$13.76	$13.76						
Dispensing	$5.21	$5.21	$5.21						
LCFS	-$15.18	-$15.18	-$15.18						
Retail Markup				$26.24	$44.30	$62.94	$17.49	$22.15	$47.20
Cost of RECs				$7.44	$7.44	$7.44	$7.44	$7.44	$7.44
Total Refueling Cost	$34.49	$44.72	$54.95	$91.99	$125.58	$175.27	$83.24	$103.43	$159.54



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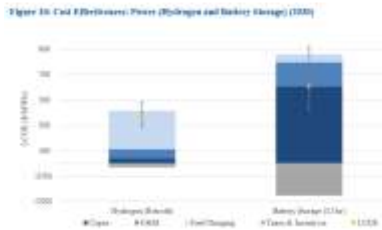
Power and Cogeneration Outputs

Hydrogen vs Electrification

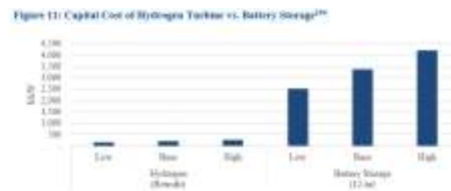
x **LCOE Cost Effectiveness - Power**

	Hydrogen (Retrofit)	Battery Storage (12-hr)
Capex	$38	$606
O&M	$73	$189
Fuel/Charging	$303	$67
Taxes & Incentives	-$30	-$252
LCOE - Base	$384	$609
LCOE - High	$483	$923
LCOE - Low	$288	$419



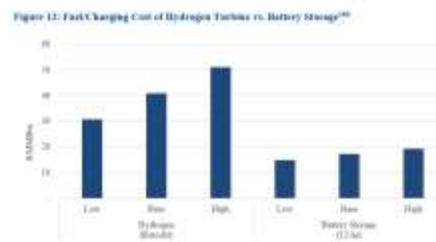
x **Capital Cost**

	Hydrogen (Retrofit)			Battery - 12 hr		
	Low	**Base**	**High**	**Low**	**Base**	**High**
Capital Expenditures	$156	$208	$260	$2,526	$3,367	$4,209



x **Fuel/Charging Cost Breakdown**

	Hydrogen (Retrofit)			Battery - 12 hr		
	Low	**Base**	**High**	**Low**	**Base**	**High**
Fuel/Charging Expenditure	$31	$41	$51	$15	$17	$19



Hydrogen vs CCS

x **LCOE Breakdown - Power**

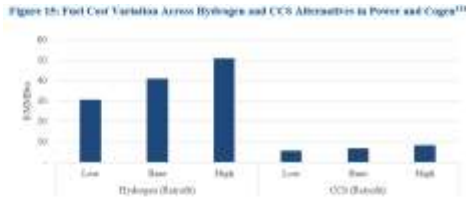
	Hydrogen (Retrofit)	CCS (Retrofit)
Capex	$12	$50
O&M	$19	$25
Fuel/Charging	$227	$70
CO2 T&S Cost	$0	$31
Taxes & Incentives	-$30	-$19
LCOE - Base	$229	$157
LCOE - High	$298	$294
LCOE - Low	$164	$120

LCOE Breakdown - Cogeneration

	Hydrogen (Retrofit)	CCS (Retrofit)
Capex	$16	$74
O&M	$31	$40
Fuel/Charging	$227	$67
CO2 T&S Cost	$0	$30
Taxes & Incentives	$2	-$23
LCOE - Base	$277	$189
LCOE - High	$351	$333
LCOE - Low	$208	$144

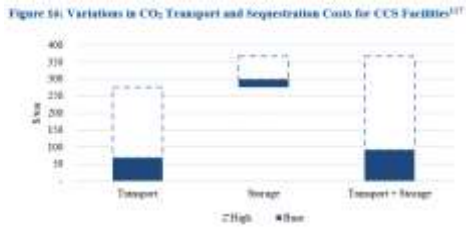
x **Fuel Cost Variation**

	Hydrogen (Retrofit)			CCS (Retrofit)		
	Low	Base	High	Low	Base	High
Fuel Cost	$30.7	$40.9	$51.2	$6.4	$8.0	$9.5



x **CO2 transport and Storage Cost Sensitivities**

	Transport	Storage	Transport + Storage
Base	$ 69	$ 23	$ 92
High	$ 207	$ 69	$ 276



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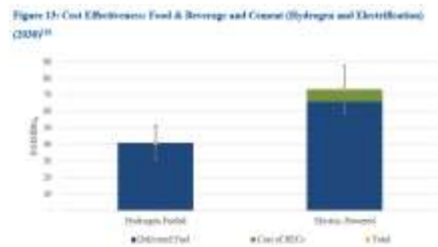
Hydrogen vs Electrification

Industry - Food & Beverage and Cement Outputs

x **Cost Effectiveness - F&B and Cement**

	Hydrogen-Fueled	Electric-Powered
Delivered Fuel	$40.9	$65.9
Cost of RECs	$0.0	$7.3
Total - Base	$40.9	$73.2
Total - High	$51.2	$88.0
Total - Low	$30.7	$58.7

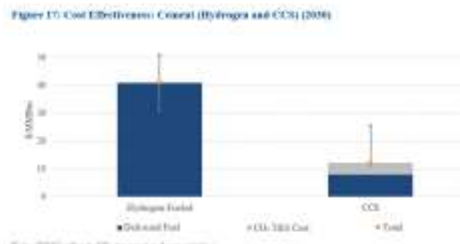


Hydrogen vs CCS

Industry - Cement Outputs

x **Cost Effectiveness - Cement**

	Hydrogen-Fueled	CCS
Delivered Fuel	$40.9	$8.0
CO_2 T&S Cost	$0.0	$4.2
Total - Base	$40.9	$12.2
Total - High	$51.2	$25.8
Total - Low	$30.7	$11.3



Industry - Refineries Outputs

x **Cost Effectiveness - Refineries**

	Clean Renewable Hydrogen	Hydrogen Abated with CCS
Delivered Hydrogen	$5.5	$1.7
CO_2 T&S Cost	$0.0	$0.1
Total - Base	$5.5	$1.8
Total - High	$6.9	$3.8
Total - Low	$4.1	$1.8