The Role of Clean Fuels and Gas Infrastructure in Achieving California's Net Zero Climate Goal

Technical appendices

November 2021

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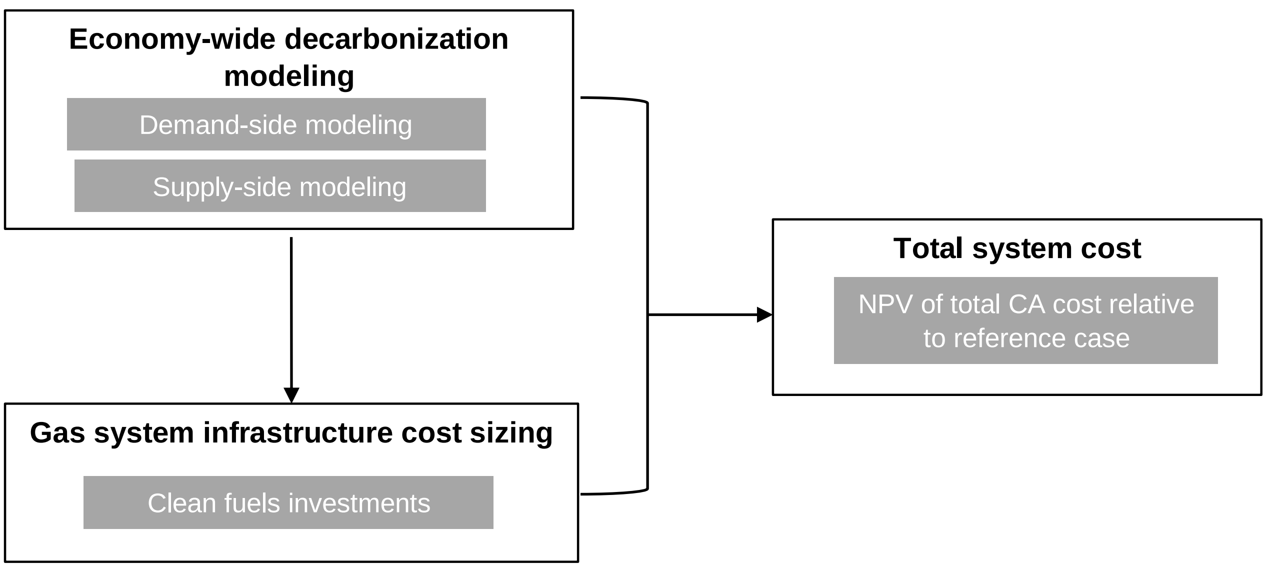
Introduction

These technical appendices provide additional detail to support the “The Role of Clean Fuels and Gas Infrastructure in Achieving California’s Net Zero Climate Goal” white paper. The following chapters outline the methodology and key assumptions in regard to (A) the economy-wide decarbonization scenario modeling and (B) clean fuels infrastructure implications and costs.

The analysis is first anchored on an economy-wide decarbonization modeling framework that looks at different potential scenarios that achieve full carbon neutrality. That economy-wide decarbonization modeling is composed of a demand-side scenario analysis and a supply-side least cost optimization. The analysis then goes beyond what has historically been done in many other full decarbonization studies to model the economy-wide decarbonization, size up needs for clean fuel infrastructure and assess cost-competitiveness and viability of various pathways to achieving full decarbonization

The outputs of both the economy-wide decarbonization modeling and the clean fuels infrastructure sizing inform a more complete assessment of total system cost. A high-level overview of the framework that informs this analysis is depicted in Exhibit 1.

Exhibit 1. Integrated framework to inform total analysis



Appendix A: Economy-wide decarbonization modeling

Overall economy-wide decarbonization modeling methodology

Modeling of the energy system in this analysis was performed using an integration of demand-side and supply-side models, both of which are numerical models with temporal, sectoral, and spatial resolution. The demand-side model is used to estimate final energy demand from the bottom-up with over sixty demand subsectors and over twenty final energy types. This final energy demand for fuels along with time-varying (8760 hour[1]) electricity demand profiles are used as inputs to the supply-side model, a linear programming model that combines capacity expansion and sequential hourly operations to find least-cost supply-side pathways. This pair of models produces energy, cost, and emissions data over the 30-year study period, 2020 – 2050. The supply-side model used for this analysis reflects detailed interactions among electricity generation, fuel production and consumption, and carbon capture, allowing accurate evaluation of coupling between these sectors in the context of economy-wide emissions constraints.

In general, this modeling and the assumptions are uncertain. They are based on assumptions related to technology development, customer behaviors, and other large-scale trends over a 30-year time period, and in some instances were selected to test a range of potential scenarios. Therefore, the results can be used to guide high-level strategic decision-making but should not be used as a forecasts.

The following sections provide additional detail on the demand-side and supply-side models.

Demand-side modeling

The demand-side model estimates energy demand for each end-use or subsector of the economy. Demand estimates are based on user decisions about technology adoption and energy service activity levels. For example, the vehicles miles traveled in the light-duty trucks subsector and sales share (adoption) of battery electric vehicles are both inputs that will likely drive final energy demand estimates for that subsector. Energy efficiency and end-use electrification measures are incorporated in demand-side scenarios, and the demand-side outputs are then used as inputs to the supply-side modeling.

Supply-side modeling

Supply-side modeling optimizes annual investments for the electricity and fuels sectors to meet carbon targets and other constraints. It incorporates estimated final energy demand in future years from the demand-side modeling, the future technology and fuel options available (including their efficiency, operating, and cost characteristics), and clean energy goals (such as Renewable Portfolio Standard, Clean Energy Standard, and carbon intensity).

The supply-side model simulates hourly electricity operations by utilizing the 8760 hourly profiles of load from the demand-side modeling, but optimizes operations for a subset of representative

[1] To cover all hours in a year.

days (“sample days”) before mapping them back to the full year to generate annual metrics. Operations are performed over sequential hourly timesteps.

For this analysis, the 2011 weather year was utilized due to the availability of time-synchronous hourly wind, solar and load data. Hourly electricity system operations were simulated for forty sample days of each model year.

In addition to the electricity system, the modeling includes the fuels system, which allows for a co-optimized (electricity & fuels) supply-side while enforcing economy-wide emissions constraints. This is important for accurate representation of the economics when electricity is used to produce fuels, for example when renewable over-generation is used for the production of hydrogen.

Assumptions and data sources

The economy-wide decarbonization modeling includes both scenario assumptions selected by SoCalGas and varying across the scenarios, and base model assumptions based on publicly available data which are held constant across all scenarios. The following two sections outline the scenario assumptions and the key base model assumptions.

Scenario assumptions

Assumptions that vary across the scenarios (referred to as “scenario assumptions”) were selected in order to better understand pathways that California could take to meet its carbon neutrality goals with varying implications for gas system infrastructure. The assumptions listed in Table A-1 below were selected to create the specific scenarios analyzed in the technical analysis.

Table A-1. Scenario assumptions

Category	Key assumptions	No fuels network	Resilient electrification	High clean fuels	High sequestration
Residential and commercial building electrification	Building electrification - measures	100% sales of gas appliances electrified by 2035	100% sales of gas appliances electrified by 2035	50% sales of gas appliances electrified by 2035	50% sales of gas appliances electrified by 2035
Transportation sales by 2035	LDV	BEV: 85% FCEV: 15%	BEV: 85% FCEV: 15%	BEV: 85% FCEV: 15%	BEV: 85% FCEV: 15%
	MDV	BEV: 90% FCEV: 10%	BEV: 90% FCEV: 10%	BEV: 50% FCEV: 50%	BEV: 50% FCEV: 50%
	HDV: Short-haul and transit buses	BEV: 100% FCEV: 0%	BEV: 100% FCEV: 0%	BEV: 50% FCEV: 50%	BEV: 50% FCEV: 50%
	HDV: Long-haul	BEV: 50% FCEV: 50%	BEV: 50% FCEV: 50%	BEV: 0% FCEV: 100%	BEV: 0% FCEV: 100%

Category	Key assumptions	No fuels network	Resilient electrification	High clean fuels	High sequestration
Renewables costs	Based on National Renewable Energy Laboratory. 2020. "Annual Technology Baseline."	Modeling based on mid-case scenario[2]	Modeling based on low-case scenario		Modeling based on mid-case scenario[3]
Pipeline blending	Maximum cap of hydrogen blending in gas pipeline (by volume)	N/A: No remaining pipelines assumed	5%	20%	No cap
Electrolyzer capex		2020: $1,000/kWe 2030: $600/kWe 2050: $375/kWe		2020: $1000/kWe; dropping to the EU ASSET Database forecasts for 2030[4]	2020: $1,000/kWe 2030: $600/kWe 2050: $375/kWe
Carbon capture and sequestration potential and cost curves	Carbon capture (CC) availability	CC available for biofuels, DAC, and industrial processes			All options for CC available: CC for power, H2 production, biofuels, industry, DAC
	Carbon sequestration[5]	No sequestration allowed	Sequestration allowed[6]	No sequestration allowed	Sequestration allowed[7]

[2] Total costs adjusted downwards for apples-to-apples comparison with scenarios run on low case.

[3] Ibid.

[4] Capros et al., "Technology Pathways in Decarbonisation Scenarios," Advanced System Studies for Energy Transition, July 2018, available at: https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf.

[5] U.S. Department of Energy, National Energy Technology Laboratory, "FE/NETL CO2 Saline Storage Cost Model," September 2017, available at: https://edx.netl.doe.gov/dataset/fe-netl-co2-saline-storage-cost-model-2017.

[6] Binned annual carbon sequestration injection potential by state with associated costs.

[7] Ibid.

Base model assumptions and input sources

The economy-wide decarbonization modeling draws upon publicly sourced data that underpin costs, potentials, and performance characteristics of fuels and resources for all of the scenarios, referred to here as "base model assumptions". The following assumptions (referred to as "key base model assumptions") are common across all scenarios and match public sources that have been frequently used in other decarbonization studies in California and other geographies.

Table A-2. Key base model assumption data sources

Category	Assumption / Input	Source
Residential building appliances / equipment	Initial residential appliance stock	2019 California Energy Commission, "Residential Appliance Saturation Survey", preliminary results[8]
	Residential building heating technology performance	NREL Electrification Futures Study, mid-technology scenario
	Residential building heating technology cost	Massachusetts 2050 Decarbonization Roadmap[9]
Transportation	Initial Light-duty vehicle stock	California Air Resources Board, EMFAC, 2021[10]
Electricity generation technologies	Renewable resource potential and performance	CPUC Integrated Resource Plan[11]
End-use load shapes	Residential and commercial heating loads	NREL Electrification Futures Study
	Light-duty vehicles	NREL Electrification Futures Study
Biomass	Cost and potential	US Department of Energy, Billion Ton Study[12]

[8] California Energy Commission, "2019 Residential Appliance Saturation Survey," CEC-200-2021-005-PO, July 2021, available at: https://webtools.dnv.com/CA_RASS/Uploads/CEC-200-2021-005-PO.pdf.

[9] Government of Massachusetts, "MA Decarbonization Roadmap," December 2020, available at: https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download.

[10] California Air Resources Board, "EMFAC," January 2021, available at: https://arb.ca.gov/emfac/.

[11] California Public Utilities Commission, "Integrated Resource Plan and Long Term Procurement Plan (IRP-LTPP)," available at: https://www.cpuc.ca.gov/irp/.

[12] US Department of Energy, "2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy," July 2016, available at: https://www.energy.gov/sites/default/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf.

Category	Assumption / Input	Source
Biogas	Cost and potential	American Gas Foundation, “Renewable Sources of Natural Gas”[13]
Conversion cost and performance	Biomass Gasification Biomass Gasification with CCUS	G. del Alamo et al.[14]
	Renewable Diesel Renewable Diesel with CCUS	G. del Alamo et al.
	Biomass Pyrolysis Biomass Pyrolysis with CCUS	Meerman, J. and E. Larson (2017)[15]
	Power-to-liquids	EU ASSET Database[16]
	Power-to-gas	Gorre, et al.[17]
Fossil fuel cost and potential	Domestic production potential of natural gas	US EIA, 2020: Natural Gas Primary – Domestic; High Oil & Gas Supply case
	Domestic production potential of oil	US EIA, 2020: Oil Primary – Domestic High Oil & Gas Supply case

[13] American Gas Foundation, “Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment,” December 2019, available at: https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

[14] International Energy Agency Bioenergy, “Implementation of bio-CCS in biofuels production: IEA Bioenergy Task 33 special report,” July 2018, available at: https://www.ieabioenergy.com/wp-content/uploads/2018/08/Implementation-of-bio-CCS-in-biofuels-production_final.pdf.

[15] The Royal Society of Chemistry, “Electronic Supplementary Material (ESI) for Sustainable Energy & Fuels,” 2018, available at: http://www.rsc.org/suppdata/c8/se/c8se00129d/c8se00129d1.pdf.

[16] Capros et al., “Technology Pathways in Decarbonisation Scenarios,” Advanced System Studies for Energy Transition, July 2018, available at: https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf.

[17] Costs data from Gorre et al., “Production Costs for Synthetic Methane in 2030 and 2050 of an Optimized Power-to-Gas Plant with Intermediate Hydrogen Storage,” Applied Energy, Volume 253, 113594, November 2019, available at: https://www.sciencedirect.com/science/article/pii/S0306261919312681?via%3Dihub. Efficiency/performance data from EU ASSET database. (Capros et al., “Technology Pathways in Decarbonisation Scenarios,” Advanced System Studies for Energy Transition, July 2018, available at: https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf.)

Category	Assumption / Input	Source
	Natural Gas Primary – Domestic cost curves	US EIA, 2020: Commodity cost of natural gas at Henry Hub. AEO low gas price forecast
	Refined Fossil Diesel; Refined Fossil Jet Fuel; Refined Fossil Kerosene; Refined Fossil Gasoline; Refined Fossil LPG	US, EIA 2020: Undelivered costs of refined fossil products. AEO low oil price forecast

Cost of capital and discount rates

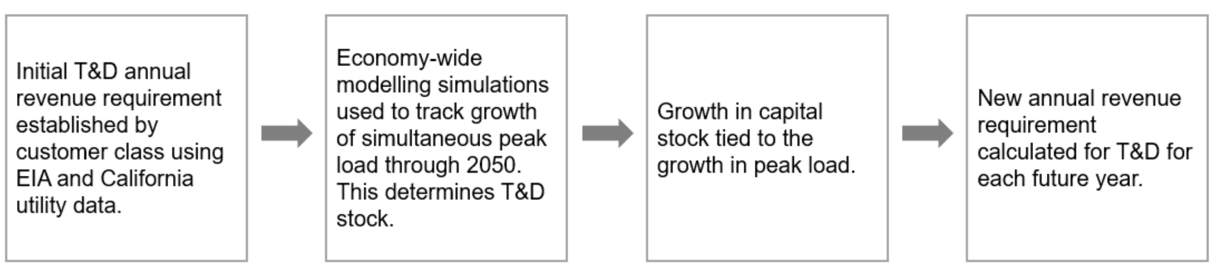
The following discount rates and cost of capital were applied in the economy-wide decarbonization modeling:

- Discount rate: 2% real
- Demand-side equipment cost of capital: 3-8% real depending on subsector
- Offshore wind: 5% real
- All other electricity generation: 4% real
- Fuel conversion technologies: 10% real

Energy delivery infrastructure

Electricity delivery infrastructure calculations were done in a four-step process explained in Exhibit A-1 below.

Exhibit A-1. Electric delivery infrastructure calculation methodology



The above calculation results in an average electricity distribution growth cost of ~$275-$310 / kW-year.[18]

[18] This electricity distribution growth cost represents the cost of per kW-year growth of the simultaneous peak across all distribution feeders.

Gas delivery infrastructure needs were modeled and sized with additional granularity, as outlined in Appendix B.

Supply portfolio results

Table A-3. Annual California electric capacity, by source technology (GW)

Scenario	Capacity	2020	2030	2040	2050
Resilient electrification	Battery storage	1	2	33	35
	Gas	36	27	36	54
	HVDC onshore wind		5	15	25
	Hydro	11	12	12	12
	Nuclear	3	1	1	1
	Offshore wind		0	2	10
	Onshore wind	6	8	8	8
	Other resources	6	4	4	3
	Pumped hydro	4	4	4	4
	Rooftop solar	11	23	30	37
	Solar	13	43	131	153
	Total	**92**	**131**	**277**	**343**
High clean fuels	Battery storage	0	4	28	24
	Gas	36	23	23	35
	HVDC onshore wind		5	15	25
	Hydro	11	12	12	12
	Nuclear	3	1	1	1
	Offshore wind		0	1	2
	Onshore wind	6	8	8	8
	Other resources	6	4	4	3
	Pumped hydro	4	4	4	4
	Rooftop solar	11	23	30	37
	Solar	13	53	205	228
	Total	**92**	**138**	**332**	**379**
High carbon sequestration	Battery storage	0	2	24	20
	Gas	36	25	27	38
	HVDC onshore wind		5	15	25
	Hydro	11	12	12	12
	Nuclear	3	1	1	1
	Offshore wind		0	1	9
	Onshore wind	6	8	8	8
	Other resources	6	4	4	3
	Pumped hydro	4	4	4	4
	Rooftop solar	11	23	30	37
	Solar	13	43	122	152
	Total	**91**	**127**	**249**	**309**

Appendix B. Clean fuels infrastructure implications and associated costs

Overview

The results of the economy-wide scenario modeling suggest that there will likely be new types of fuels, such as hydrogen, in the gas pipeline system; new users of the pipeline network; and changing throughput volumes to existing users.

This analysis relies on historical SoCalGas data, research conducted by SoCalGas and by third parties (e.g., universities, national labs, other utilities, etc.), market forecasts from a range of sources, and learnings from other geographies. This analysis provides a high-level view of the types of investments that could be required and is intended to inform long-term, high-level strategy. The assumptions have inherent uncertainty and can change quickly as technologies and markets evolve. The assumptions underlying this analysis should be monitored continuously to determine how the results and implications evolve over time.

Focus geography

This analysis was conducted considering the SoCalGas system configuration and pipeline miles and inventory, lay out of load centers, natural gas storage, etc., as described in the following sections. This SoCalGas-focused analysis was used to calculate potential clean fuels infrastructure investment needs for the utility. The numbers listed throughout Appendix B reflect the analysis for SoCalGas territory.

To derive total system cost for all of California, the investment needed was scaled up to all of California using a scaling factor of 2.15, based on the ratio of SoCalGas pipeline mileage (both transmission and distribution) relative to total California pipeline mileage.[19]

Hydrogen transmission (Tx) pipelines – new-build

Inputs to size the costs associated with building new hydrogen transmission pipeline include:

1. Distance
2. Region
3. Costs

[19] SoCalGas, "Southern California Gas Company's Service Territory", December 2013, available at: https://www.socalgas.com/documents/news-room/fact-sheets/ServiceTerritory.pdf; National Conference of State Legislatures, "Making State Gas Pipelines Safe and Reliable: An Assessment of State Policy," March 2011, available at: https://www.ncsl.org/documents/energy/PipelineWebBrief.pdf.

Distance

The miles of new hydrogen transmission pipeline that could be built are largely driven by (1) the average concentration of hydrogen in the gas pipelines, as determined by the economy-wide scenario modeling, (2) pure hydrogen demand from dedicated pipelines, and (3) the geography of the SoCalGas territory.

For the first consideration, Section 4.4 of "The Role of Clean Fuels and Gas Infrastructure in Achieving California's Net Zero Climate Goal" outlines the considerations, constraints, and assumptions for blending of hydrogen into existing natural gas pipelines. Of the more plausible scenarios, only the High clean fuels scenario does not require new transmission pipelines to be built based on the hydrogen concentrations in the pipelines; in this scenario it is assumed that technological innovation enables higher hydrogen concentrations (20% by volume) in existing pipelines, beyond what is considered viable today without extensive retrofits and/or replacements.

For the second consideration, the existing SoCalGas transmission map was assessed to determine where new hydrogen pipelines could be needed to connect hydrogen supply regions (e.g., southeastern part of California) to demand-centers (e.g., Los Angeles). The clean fuels infrastructure analysis found that additional pipeline miles will likely be needed to meet industrial cluster needs and along transit corridors. Those assumptions are summarized in Table B-1.

The number of hydrogen compressor stations needed is driven by the number of miles of new hydrogen transmission pipeline. On average, SoCalGas currently has one compressor station for every approximately 150 miles of backbone natural gas transmission pipeline. This same ratio is applied to estimate the number of hydrogen-specific compressor stations that would be needed for each scenario, based on the estimated number of miles of new hydrogen transmission pipeline described above. In the High clean fuels scenario, where hydrogen is blended to higher levels through the gas network, it assumed that new compressors stations would need to be built across the system to accommodate this blend of hydrogen in the transmission pipelines.

Region

The study looks at a high-level geographic breakdown of new hydrogen transmission pipeline as one of the considerations for estimating hydrogen infrastructure needs. Per-mile cost of pipeline varies based on type of geography, with different per-mile costs associated with (1) low-population regions, (2) non-coastal populated regions, and (3) coastal populated regions. The percentage of hydrogen pipeline located in each of these three types of geographies is approximated based on an assessment of where hydrogen pipelines are needed, as summarized in Table B-1.

Table B-1. Assumed new hydrogen transmission pipeline mileage and geographic breakdown in SoCalGas territory

Scenario	Hydrogen Tx miles	Geographic breakdown	Rationale for assumed mileage and geographic breakdown
Resilient electrification	~400 miles	Low-population region: 0-5% Non-coastal populated region: 80-85% Coastal populated region: 10-20%	Based on locations of industrial clusters and heavy transportation use cases in SoCalGas territory, most of the new pipeline would be built in and around the LA Basin; only a small fraction of pipeline would be in a low-population region, most relatively far from the coast.
High clean fuels	0 miles	N/A	If a high percentage of hydrogen in the existing natural gas pipelines could be achieved with minimal retrofits (requiring innovation beyond what is currently considered feasible), existing pipelines are assumed to be sufficient for needed hydrogen delivery, including extracting hydrogen from blended gas pipelines for hydrogen end-uses, so no new hydrogen transmission pipelines are built.
High carbon sequestration	~400 miles	Low-population region: 0-5% Non-coastal populated region: 80-85% Coastal populated region: 10-20% (remainder)	Based on locations of industrial clusters and heavy transportation use cases in SoCalGas territory, most of the new pipeline would be built in and around the LA Basin; only a small fraction of pipeline would be in a low-population region, most relatively far from the coast.

Costs

This study reviewed a range of hydrogen transmission costs based on various factors that were informed by experiences in other geographies. This information was used to scale up the historical cost of natural gas infrastructure to estimate the potential cost of analogous hydrogen infrastructure. While these estimates considered some geographical factors, this study did not include a detailed, project level analysis that accounts for granular locational cost impacts. Based on these estimated costs, per-mile capex associated with new construction of 30" hydrogen transmission pipelines in SoCalGas territory are estimated to be $7 - $36M, costs vary by region.

Based on North American natural gas pipeline cost data from 2000 to 2020, pipeline capex costs are calculated to increase at a rate of 3% p.a., over inflation.[20] Annual operating costs for hydrogen transmission pipelines are assumed to be 0.8-1.7% of initial capex.[21]

Compressor station costs vary widely as they are based on numerous factors including site work requirements, foundation, prime mover and compressor package, appurtenances, instrumentation, piping, environmental (CEQA) mitigation, and performance testing, among others. There is also variability driven by the material, diameter, wall thickness, and operating pressure of future hydrogen pipelines; these would require detailed engineering analyses not performed in this effort.

Hydrogen compressor station capex is estimated to range from approximately $300M to 550M. Cost are estimated to grow at a rate of 1% p.a., over inflation. Annual operating costs, excluding electricity costs associated with compression, are assumed to be 0.8 – 1.7% of capex.[22]

Hydrogen distribution (Dx) pipelines – new-build

Inputs to size the costs associated with building new hydrogen distribution pipeline include:

1. Distance and cost
2. Gas Blend Separation

Distance and cost

An analysis specific to the pipelines in the Los Angeles Basin was conducted to determine the number of new hydrogen distribution pipeline miles needed for each scenario. This was used as a "reference" case; each scenario was then sized based on the hydrogen needed in the distribution pipeline system relative to the Los Angeles Basin.

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[20] Based on publicly available FERC filings and EIA data.

[21] Gas for Climate, "European Hydrogen Backbone: How a Dedicated Hydrogen Infrastructure Can be Created," p. 20, July 2020, available at: https://gasforclimate2050.eu/wp-content/uploads/2020/07/2020_European-Hydrogen-Backbone_Report.pdf.

[22] Gas for Climate, "European Hydrogen Backbone: How a Dedicated Hydrogen Infrastructure Can be Created," p. 20, July 2020, available at: https://gasforclimate2050.eu/wp-content/uploads/2020/07/2020_European-Hydrogen-Backbone_Report.pdf.

Distribution pipeline mileage in the Los Angeles Basin is inventoried at a high level based on the following pipeline variables that influence the feasibility of hydrogen blending:

- Pipeline pressure (medium-pressure (< 60 psg); high-pressure ($\geq$ 60 psg))
- Pipeline vintage (pre-1970; post-1970)
- Pipeline material (plastic; steel)[23].

The various combinations of pipeline profiles along these dimensions are categorized into different "archetypes," and the approximate pipeline mileage associated with each archetype in the LA Basin is estimated. Each archetype is assessed based on what would be required to accommodate high hydrogen concentrations: full replacement, repair/retrofit, or no new investment. Given uncertainty around feasibility of different hydrogen concentrations across different types of distribution pipeline, there is a range of estimated potential investment needs to accommodate higher hydrogen blends.

It is assumed that the majority of distribution pipeline that needs investment to accommodate higher hydrogen blends would be replaced rather than repaired. This assumption is based on SoCalGas historical and current distribution pipeline replacement procedures: plastic pipeline is typically cut out and replaced when it leaks; similarly, steel pipe is mainly replaced as opposed to repaired. Adjustments to the sizing have been made to account for pipeline that may be addressed through utility programs

This analysis results in a wide range of estimates for the miles of pipeline to be replaced, repaired/retrofitted, or left as-is. For each scenario, mileage is scaled back from the "reference case" estimation of hydrogen demand and concentration for the Los Angeles Basin. Table B-2 below summarizes the new hydrogen distribution pipeline mileage assumptions.

[23] Within plastic: Aldyl-A; non-Aldyl-A. Within steel: low/medium-grade; high-grade (the latter being defined as X60 or higher); cathodically protected; not cathodically protected

Table B-2. Assumed new hydrogen distribution pipeline mileage in SoCalGas territory

Scenario	Dx pipeline mileage	Assumption rationale
Resilient electrification	200 – 2,500 miles	Assumed that serving LA industrial customers (only those using H_2 as a feedstock) and fueling stations will require 5-15% of the new Dx pipeline investments required by the distribution reference case of all Los Angeles Basin
High clean fuels	0 miles	If a high percentage of hydrogen in the existing natural gas pipelines could be achieved with minimal retrofits (requiring innovation beyond what is currently considered feasible), existing pipelines are assumed to be sufficient for needed hydrogen delivery, so no new hydrogen distribution pipelines are assumed to be built
High carbon sequestration	500 – 3,500 miles	Assumed that serving LA industrial customers (for feedstock and fuel) and fueling stations will require 10-20% of the new Dx pipeline investments required by the distribution reference case of all the Los Angeles Basin

Distribution pipeline cost assumptions are based on SoCalGas historical averages for polyethylene distribution pipeline build. An assumed 10-20% adder is included for overhead based on traditional adders for large pipeline build or replacement programs.

Gas Blend Separation

This analysis assumes that if hydrogen is transported via blending with natural gas in existing pipelines – as it could be in a high clean fuels scenario -, dedicated hydrogen end-uses will require the hydrogen to be separated from the natural gas at the end-use.

The mass of hydrogen to be separated from natural gas in the pipeline is calculated as the sum of 2050 fueling station demand and industrial hydrogen demand, shown in Exhibit 4.3 of "The Role of Clean Fuels and Gas Infrastructure in Achieving California's Net Zero Climate Goal". In the High clean fuels scenario, it is assumed that 80-90% of hydrogen delivered to fueling stations would be transported via blending in the natural gas pipeline and so would need to be separated at the fueling station. The remaining 10-20% of hydrogen would come directly from on-site or very proximate hydrogen production. For industrial demand, it is assumed that 60-80% of delivered hydrogen would be transported via blending in the natural gas pipeline and so would need to be separated at the industrial customer site. The remaining consumed hydrogen is assumed to be utilized as a hydrogen-natural gas blend (e.g., combustion) and so would not require separation.

To separate hydrogen from natural gas for those dedicated end-uses, electrochemical hydrogen purification and compression (EHPC) is the assumed separation technology. In this analysis, capex is assumed to be $500 per kg-$H_2$/day of capacity from 2025-2050. The analysis also assumes 360 operating days per year and an equipment lifetime of 20 years.

Hydrogen transmission (Tx) pipelines – upgrades to existing pipeline

Inputs to size the costs associated with upgrading existing transmission pipeline for hydrogen include:

1. Pipeline Requirements, Installation, and Costs
2. Compressor Stations
3. Blending Stations
4. Chromatographs

Pipeline Requirements, Installation, and Costs

Pipeline retrofits are assumed to be possible only where parallel natural gas transmission pipelines already exist, so that one pipeline could be temporarily shut down for retrofits while the other pipeline(s) continue serving customers. Within SoCalGas territory, these areas were identified primarily as the South Desert (roughly 150 miles between Blythe and Moreno Valley), pipelines moving west from Moreno, and pipelines moving west from Adelanto. Areas where hydrogen transmission is needed but parallel pipelines do not exist are assumed to require new hydrogen pipelines, as described in the above section, "Hydrogen transmission (Tx) pipelines – new-build." Methods do exist to shut down sections of transmission pipeline for repairs that do not have a parallel pipeline – such as back feeds and bypasses – while continuing to serve downstream customers. However, given the scale of retrofits required to build the clean fuels network, these solutions have limitations and are not assumed in this analysis.

The assumptions for retrofitted mileage are summarized in Table B-3. Assumed pipeline retrofit costs will vary by geography, as they are informed by new-build costs. Table B-3 also summarizes the mileage assumptions and geographic breakdown of retrofitted pipeline miles needed.

Table B-3. Assumed retrofitted transmission pipeline mileage and geographic breakdown in SoCalGas territory

Scenario	Tx pipeline mileage	Assumed geographic breakdown	Assumption rationale
Resilient electrification	175 miles	Low-population region: 60-75% Non-coastal populated region: 25-40% Coastal populated region: 0% (remainder)	The majority of retrofitted pipeline would be in the South Desert between Blythe and Moreno Valley (along I-10), as well as near Adelanto. These are classified as low-population regions. The remaining retrofits would occur in more populated inland regions.
High clean fuels	350 – 700 miles	Low-population region: 60-75% Non-coastal populated region: 25-40% Coastal populated region: 0% (remainder)	It is assumed that a high percentage of hydrogen in the existing natural gas pipelines could be achieved with minimal retrofits, with 10-20% of all transmission pipelines needing retrofits to accommodate the higher percentage of hydrogen. These hydrogen concentration levels are not considered feasible today, without significant retrofits and/or replacements, so this is an aspirational case requiring technological advancements.
High carbon sequestration	175 miles	Low-population region: 60-75% Non-coastal populated region: 25-40% Coastal populated region: 0% (remainder)	The majority of retrofitted pipeline would be in the South Desert between Blythe and Moreno Valley (along I-10), as well as near Adelanto. These are classified as low-population regions. The remaining retrofits would occur in more populated inland regions.

Retrofit costs are assumed to be 10-35% of the costs of a new hydrogen transmission pipeline, described above in “Hydrogen transmission (Tx) pipelines – new-build”.[24] In general, retrofit costs may include activities such as nitrogen purging; dismantling of connections; crack

[24] Gas for Climate 2050, “European Hydrogen Backbone: How A Dedicated Hydrogen Infrastructure Can Be Created,” p. 19, July 2020, available at: https://gasforclimate2050.eu/wp-content/uploads/2020/07/2020_European-Hydrogen-Backbone_Report.pdf.

monitoring and repair; replacement of valves, fittings, and meters; and hydrostatic pressure testing.

Compressor Stations

Compressor stations would require retrofits to accommodate high hydrogen blending. The number of compressor stations to be retrofitted is calculated in the same way as for new-build compressor stations: proportional to the number of miles of pipeline retrofitted to accommodate higher hydrogen blending, as described above in “Hydrogen transmission (Tx) pipelines – new-build”. The cost of compressor station retrofits to accommodate significantly higher hydrogen blends is assumed to be roughly equivalent to the cost of building a new hydrogen compressor station.[25] These costs are described in “Hydrogen transmission (Tx) pipelines – new-build”.

Blending Stations

Research has shown that hydrogen could be injected into the natural gas grid via blending stations.[26] Since the “High clean fuels” scenario is the only scenario involving blending hydrogen throughout the entire gas grid – as opposed to delivering hydrogen through dedicated hydrogen pipelines – the number and cost of blending stations is relevant only for that scenario.

The number of blending stations required in the High clean fuels scenario is estimated to be approximately 20 to 40, based on the number of hydrogen production facilities that could be required in that scenario from the results of the economy-wide decarbonization modeling. This assumes one blending station per centralized hydrogen production facility, and approximately 1 to 2 GW of capacity at each centralized hydrogen production facility. The costs of blending stations were estimated based on experiences from other geographies and initial data from pilot projects.

Chromatographs

Chromatographs are used on the system where precise gas quality measurement and tracking are required. Since the “High clean fuels” scenario is the only scenario involving blending hydrogen throughout the entire gas grid – as opposed to delivering hydrogen through dedicated hydrogen pipelines – the number and cost of chromatograph replacement is relevant only for that scenario. Based on blend limits published in recent literature, it is assumed that all chromatographs would need to be replaced in order to accommodate ~20% hydrogen blends.[27] Chromatograph replacements and new installations are assumed to have relatively similar costs. The cost inputs are informed by historical SoCalGas cost data.

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[25] Ibid.

[26] National Renewable Energy Laboratory, “HyBlend Project To Accelerate Potential for Blending Hydrogen in Natural Gas Pipelines,” November 2020, available at: https://www.nrel.gov/news/program/2020/hyblend-project-to-accelerate-potential-for-blending-hydrogen-in-natural-gas-pipelines.html.

[27] Altfeld, K. and Pinchbeck, D., “Admissible hydrogen concentrations in natural gas systems,” *Gas for Energy*, p. 7, March 2013, available at: https://gerg.eu/g21/wp-content/uploads/2019/10/HIPS_Final-Report.pdf.

Hydrogen distribution (Dx) pipelines – upgrades to existing pipeline

Inputs to size the costs associated with upgrading existing distribution pipeline for hydrogen include:

1. Pipeline miles retrofitted for hydrogen
2. Pipeline retrofit cost per mile

Pipeline miles retrofitted for hydrogen

In the "Resilient electrification" scenario and the "High carbon sequestration" scenario, existing distribution pipeline replacement programs are assumed to approximate the costs of distribution infrastructure retrofit needs, as, based on experiences from other geographies, it is anticipated that a primary action to make the system "hydrogen-ready" will be adopting modern plastic pipelines. The "High clean fuels" scenario assumes that existing pipelines can handle ~20% hydrogen concentrations with minimal retrofits required to existing pipelines; this would require an innovation beyond what is currently feasible today on the California system. Therefore, this case is assumed to require retrofit of 5-10% of all distribution pipeline, incremental to the miles of pipeline that SoCalGas currently plans to replace via existing replacement programs, subject to regulatory approval.

Pipeline retrofit cost per mile

The low range of the costs to retrofit distribution pipeline for higher hydrogen blending is assumed to be ~$50,000/mile, consistent with the cost to replace necessary valves and seals, assuming the pipeline is largely "hydrogen-ready" already. The high range of the costs is assumed to be as high as $500,000/mile: roughly 25% of the high estimate for laying new distribution pipeline, consistent with research estimates that retrofits cost 10-35% of new pipeline.[28]

Hydrogen fueling stations

Inputs to size the costs associated with hydrogen fueling stations for Fuel Cell Electric Vehicles (FCEVs) include:

1. Hydrogen fueling station capacity need
2. Fueling station quantity and cost

Hydrogen fueling station capacity need

The forecasted fueling demand for each scenario is an output of economy-wide decarbonization scenario modeling, listed by scenario in Table B-4. To determine needed fueling station

[28] Gas for Climate 2050, "European Hydrogen Backbone: How A Dedicated Hydrogen Infrastructure Can Be Created," p. 19, July 2020, available at: https://gasforclimate2050.eu/wp-content/uploads/2020/07/2020_European-Hydrogen-Backbone_Report.pdf.

capacity, a 20% buffer is added to the forecasted fueling demand to account for varying rates of station utilization.

Fueling station quantity and cost

The number of fueling stations is estimated such that total daily fueling capacity satisfies the total fueling demand forecasted by the decarbonization modeling. Because smaller stations have higher per-kg costs, the low end of each scenario's fueling station cost range represents a greater concentration of larger stations while the high end represents a greater concentration of smaller stations. Fueling station costs are assumed to vary based on fueling station size. These costs were provided for 350-bar stations (for medium-duty and heavy-duty vehicles) and 700-bar stations (for light-duty vehicles) by a proprietary, third-party data source.

Table B-4. Assumed number and size of fueling stations for SoCalGas territory

Scenario	Daily fueling demand (kg H2 per day)	Number of stations for low end of cost range	Number of stations for high end of cost range
Resilient electrification	~2M	LDV (700 bar) • Large: 75 stations • X-Large: 225 stations MDV/HDV (350 bar) • "Large as needed" (~16,000 kg/day): 70 stations	LDV (700 bar) • Large: 980 stations MDV/HDV (350 bar) • X-Large: 65 stations • "Mega" (15,000 kg/day): 20 stations • "Large as needed" (~16,000 kg/day): 35 stations
High clean fuels	~4.5M	LDV (700 bar) • Large: 75 stations • X-Large: 225 stations MDV/HDV (350 bar) "Large as needed" (~50,000 kg/day): 70 stations	LDV (700 bar) • Large: 980 stations MDV/HDV (350 bar) • X-Large: 25 stations • "Mega" (15,000 kg/day): 110 stations • "Large as needed" (~50,000 kg/day): 35 stations
High carbon sequestration	~4.5M	LDV (700 bar) • Large: 75 stations • X-Large: 225 stations MDV/HDV (350 bar) • "Large as needed" (~50,000 kg/day): 70 stations	LDV (700 bar) • Large: 980 stations MDV/HDV (350 bar) • X-Large: 25 stations • "Mega" (15,000 kg/day): 110 stations • "Large as needed" (~50,000 kg/day): 35 stations

Hydrogen storage

Inputs to size the costs associated with hydrogen storage include:

1. On-site storage capacity need and cost for fueling stations and industry
2. Storage capacity leveraging existing underground storage
3. Remaining hydrogen storage capacity need and cost

On-site storage capacity need and cost for fueling stations and industry

The additional on-site hydrogen storage capacity needed for fueling stations in 2050 is estimated based on the system-wide daily hydrogen fueling station capacity, an output of the economy-wide decarbonization scenario modeling and the same value used for the fueling station sizing – and:

a. Adjusted up by 0-10% to represent the additional aboveground storage capacity needed, beyond the on-site storage costs for hydrogen fueling stations already accounted for in fueling station capex estimates
b. Added a 20% buffer to daily station capacity for additional reliability through on-site storage.

The storage capacity needed for industrial customers in 2050 was estimated based on the system-wide annual industrial hydrogen usage (TBtu H_2 per year) for each scenario – an output from economy-wide decarbonization scenario model and:

a. Adjusted up by 1-1.5% to represent the aboveground storage capacity needed (equivalent to ~3-5 days of on-site storage)
b. Added a 20% buffer for additional reliability through on-site storage.

Aboveground gas pressure vessels (100 kg H_2 capacity, at 500 bar) are assumed to determine on-site storage costs.

Storage capacity leveraging existing underground storage

A high-level and preliminary assessment of the suitability of SoCalGas underground storage (UGS) facilities for hydrogen blending suggests that some of the existing SoCalGas storage fields could have potential for low volumes of hydrogen blending, though significantly more analysis is needed for this to be confirmed. In the “High clean fuels” scenario, it is assumed that hydrogen concentrations up to 10% could be achieved in one of the existing UGS facilities. In other scenarios, a single UGS facility is assumed to store up to 1% hydrogen, with 0% hydrogen blending in all other UGS facilities. More detailed analysis is required, along with research and testing, to determine whether these hydrogen concentrations are feasible in existing UGS facilities.

Remaining hydrogen storage capacity need and cost

The economy-wide decarbonization scenario modeling estimates the total hydrogen storage capacity needed for each scenario, excluding site-specific on-site storage needs (e.g., storage tanks for back-up at a fueling station or industrial site). To estimate infrastructure investment needed for hydrogen storage, the hydrogen storage capacity output from the scenario modeling was used as a low-end; the high-end was assumed to be two times that capacity. The assumed hydrogen storage capacity needed for each scenario is shown in Table B-5 below. The hydrogen storage capacity assumed to be provided by blending into existing UGS facilities, described in the above section, is netted out from that total hydrogen storage capacity need to determine the remaining storage capacity that needs to be built.

Based on the volume of hydrogen storage capacity needed, large and medium aboveground liquid storage tanks and hydrogen liquefaction are estimated to be the most economical storage options.[29] Large aboveground storage tanks (3,500 tons H_2 capacity, with a liquefaction plant capacity of 500 tons H_2 per day) are less expensive per unit of hydrogen stored, but likely not practical given the need for hydrogen storage to be distributed across the territory near demand centers. Thus, multiple medium aboveground storage tanks are assumed to address the remaining hydrogen storage need.

Table B-5. Assumed hydrogen storage capacity needed in SoCalGas territory

Scenario	Total storage capacity needed based on scenario modeling (bscf H_2)	Assumed storage capacity met through blending in existing UGS facilities (bscf H_2)	Assumed remaining storage capacity met through aboveground liquid tanks (bscf H_2)
Resilient electrification	2.3 – 4.6	0 – 0.2	2.1 – 4.6
High clean fuels	3.4 – 6.8	0.2 – 1.9	1.5 – 6.6
High carbon sequestration	1.1 – 2.1	0 – 0.2	0.8 – 2.1

Aboveground liquid storage tank and liquefaction plant costs are included in storage capex assumptions. OpEx costs are informed by proprietary third-party data.

[29] Other options analyzed included hydrogen storage in the form of ammonia; aboveground gas pressure vessels; and storage in salt caverns in Utah, with hydrogen transported from salt caverns to California population centers via pipeline. Different volumes of hydrogen storage capacity needed could influence which storage option is the most cost effective.

CO_2 pipelines

Inputs to size the costs associated with CO_2 pipelines include:

1. CO_2 pipeline miles and cost
2. CO_2 compressor stations
3. CO_2 booster pumps

CO_2 pipeline miles and cost

Analysis suggests that CO_2 pipelines are more cost-effective when connecting carbon-emitting industrial clusters (as opposed to isolated sites) to sequestration or utilization sites.[30] This CO_2 pipeline analysis focuses on four industrial clusters in SoCalGas territory: Kern County, Los Angeles, southwest San Bernardino County, and midwest San Bernardino County.

A geospatial analysis identifies potential CO_2 pipeline routes that followed existing rights-of-way and minimized pipeline mileage needed to connect the San Bernardino County clusters to CO_2 sequestration sites in the San Joaquin Valley. Those exact pipeline routes and associated mileage are illustrative and should be refined by engineering and construction analyses. This analysis informs the CO_2 pipeline mileage assumed for each scenario.

Table B-6. Assumed CO2 pipeline miles required in SoCalGas territory

Scenario	Assumed CO_2 pipeline (miles)	Assumption rationale
Resilient electrification	300 – 375	Pipelines primarily to connect emitters to sequestration sites
High clean fuels	250 – 300	Pipelines primarily to connect emitters to carbon utilization sites. Assumes that an additional 5-10 miles of pipeline would be needed to connect industrial clusters with a nearby utilization site.
High carbon sequestration	200 – 350	Pipelines primarily to connect emitters to sequestration sites

[30] Global CCS Institute, “Transporting CO_2: Fact Sheet,” available at: https://www.globalccsinstitute.com/wp-content/uploads/2018/12/Global-CCS-Institute-Fact-Sheet_Transporting-CO2-1.pdf.

CO_2 pipeline capex is estimated to be approximately $3.4M to $6M per mile. The low end of the range is based on a review of five long-haul CO_2 pipelines in North America,[31] whose average construction cost is approximately $0.22M/inch-mile; a pipeline diameter of 16 inches was then used to arrive at $3.4M/mile. The high end of the assumed CO_2 pipeline cost range comes from a cost estimation analysis scaling costs to account for more difficult installation conditions for a similarly sized CO_2 pipeline. CO_2 pipeline capital costs are assumed to increase at a rate of 3% p.a., over inflation, in line with estimates for natural gas transmission pipeline cost increases described above in "Hydrogen transmission (Tx) pipelines – new-build". Pipeline annual opex is assumed to be 2-3% of capex.[32]

CO_2 compressor stations

In all scenarios the analysis assumes that 1 to 2 compressor stations are needed to compress the gaseous CO_2 to a supercritical state. Multiple industrial sites and clusters could send gaseous CO_2 to a shared compressor station, to reduce expensive compressor station build-out. The costs of initial compression – to send an emitter's gaseous CO_2 effluent into the pipeline – are excluded, assuming they would be site-specific investment needs. Based on research from other geographies, CO_2 compressor station capex is estimated to be approximately $127M to 212M per station.[33] CO_2 compressor station annual opex is assumed to be 2% of initial capex.

CO_2 booster pumps

Using a research analysis based on a 2018 FE/NETL transport cost model, it is estimated that one booster pump would be needed for pipeline distances between 62 to 250 miles. For each scenario, the total CO_2 pipeline mileage needed is divided by 250 miles and rounded up to the nearest integer to estimate the number of booster pumps needed. Capex is calculated to be $1.8M per booster pump. Annual opex is calculated to be $0.9M to 1.1M per pump per year, with the range reflecting different electricity cost assumptions.[34]

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[31] Kinder Morgan Centerline (Permian Basin), Kinder Morgan Eastern Shelf (Permian Basin), Alberta Carbon Trunk line (Alberta), Denbury Green (US Gulf Coast), and Denbury Greencore (US Rockies)

[32] Dubois et al., "CO_2 Pipeline Cost Analysis Utilizing a Modified FE/NETL CO_2 Transport Cost Model Tool," p. 2, August 2017, available at: http://www.kgs.ku.edu/PRS/ICKan/2018/Aug/1_Poster_Dubois_McFarlane_2017_DOE-NETL_PipelineModeling.pdf.

[33] Mallon et al., "Costs of CO_2 Transportation Infrastructures," 37 Energy Procedia 2969, 2013, available at: https://doi.org/10.1016/j.egypro.2013.06.183. $127-212M estimate based on sub-estimates of: €78.9-131.5M per station, in 2011 euros; a 2011 USD/EUR conversion rate of 1.3924; and a 2020 USD / 2011 USD conversion rate of 1.16. To arrive at the first sub-estimate, it is observed from the literature that the compressor capex is €26.3M for a discharge pressure of 150 bar and a throughput of 6 Mton/year of CO_2 (p.2976, Table 4). According to the cost figures from the FEED studies (p.2977, Table 5), compressors are roughly 1/3 to 1/5 of the cost of compressor stations. Thus, compressor station costs were estimated as €26.3M x (3 or 5).

[34] Dubois et al., "CO_2 Pipeline Cost Analysis Utilizing a Modified FE/NETL CO_2 Transport Cost Model Tool," August 2017, available at: http://www.kgs.ku.edu/PRS/ICKan/2018/Aug/1_Poster_Dubois_McFarlane_2017_DOE-NETL_PipelineModeling.pdf.

Fuel cells

Fuel cells are assumed to be used in two main functions across the various scenarios. First, they could be demanded by a broad range of customer types who desire additional reliability/resiliency, particularly customers in high wildfire risk areas and critical loads. Second, the system will likely require additional resiliency in large urban areas. In some scenarios, this analysis assumes fuel cells needed in the LA Basin are located at distribution-level substations to provide baseload or back-up power (varies by scenario). The quantitative assumptions that reflect these system configurations are driven by inputs that include:

1. Broad customer demand for back-up power
2. Additional system resiliency for urban areas
3. Fuel cell cost

Broad customer demand for back-up power

To estimate the potential investment needed in fuels cells to meet broad customer demand for back-up power, an analysis was conducted considering factors such as critical loads, the business models of industrial and commercial customers that influences their willingness to pay for back-up power, and the needs of residential customers at high risk during outages. Different adoption rate ranges for different customer categories were assumed and applied to the total load of the respective customer category to estimate the fuel cell capacity needed to address broad customer demand for back-up power.

Additional system resiliency for urban areas

The “Resilient electrification” scenario assumes fuel cells for resiliency in the Los Angeles Basin. The maximum peak load for Los Angeles is used to estimate the magnitude of the fuel cell investment needed to provide additional resiliency in this scenario.

The maximum peak load for southern California’s residential, commercial, and industrial segments is an output of the economy-wide decarbonization scenario modeling. It is assumed that 50% of that southern California peak load will originate from the Los Angeles basin.

Fuel cell cost

Fuel cell capex and opex estimates vary based on fuel cell size – both capacity and energy storage. Residential fuel cells are assumed to have a 1:1 ratio of kW of fuel cell capacity to kWh of energy storage. Commercial fuel cells are assumed to have a 1:1.67 ratio, and industrial/commercial fuel cells are assumed to have a 1:2.67 ratio. So, if a commercial fuel cell is sized at 10 kW, it can store up to 16.67 kWh of energy (i.e., it can provide back-up power at 10k W for 1.67 hours). Fuel cell capex is assumed to decline by roughly 70-75% between 2020 and 2050.

Cautionary Statement Regarding Forward- Looking Information

This study contains statements that constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements are based on assumptions with respect to the future, involve risks and uncertainties, and are not guarantees. Future results may differ materially from those expressed in any forward-looking statements. These forward-looking statements represent our estimates and assumptions only as of the date of this study. We assume no obligation to update or revise any forward-looking statement as a result of new information, future events or other factors.

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