DOE Hydrogen and Fuel Cells Program Record	
Record #: 19001	**Date: September 9, 2019**
Title: Current Status of Hydrogen Liquefaction Costs	
Originators: Elizabeth Connelly, Michael Penev, Amgad Elgowainy, Chad Hunter	
Peer Reviewed By: Al Burgunder,[1] Andrew Martinez,[2] Satish Tamhankar[3]	
Approved By: Neha Rustagi, Fred Joseck, Sunita Satyapal	**Date:** August 6, 2019

Item

The total cost of hydrogen liquefaction plant facilities in current markets is estimated to range from $50 million to $800 million for capacities ranging from 6,000 kg/day to 200,000 kg/day, respectively.[4] This DOE Hydrogen and Fuel Cells Program Record uses recent public information on the cost of new liquefaction plants to validate national laboratory cost models. In this case, the cost models estimate a capital cost of $160 million for a 27,000 kg/day plant, which is only about 7% higher than the industry estimate. The entire liquid hydrogen supply chain (production, liquefaction, delivery, and dispensing) associated with this capacity level (i.e., 27,000 kg/day plant) was also modeled, estimating a dispensed cost of $14.25 per kilogram of hydrogen at the pump (including production, delivery, and dispensing, untaxed) for fueling commercially available fuel cell cars.

Background

Demand for hydrogen in emerging and growing sectors, such as light-duty fuel cell electric vehicles (FCEVs) and material handling equipment, will require construction of new large-scale hydrogen production and distribution infrastructure. Liquid hydrogen supply is often desired due to its higher energy density compared to gaseous hydrogen and lower cost at high volumes [1].[5] To meet the expected growth in demand, gas supply companies have recently announced plans to develop four new liquefaction plants [2–5], which are expected to increase the U.S. liquid hydrogen production capacity by at least 40% [6].

Recent public information on the cost of new commercial liquefaction plants provides a useful benchmark to validate results from national laboratory models such as the Hydrogen Analysis (H2A) production model and Hydrogen Delivery Scenario Analysis Model (HDSAM). For example, one of the planned

---

[1] Praxair, Inc.
[2] California Air Resources Board
[3] Retired—Linde
[4] This total capital investment includes land and equipment associated with a steam methane reformer for hydrogen, production, the hydrogen liquefier, and terminal required for distributing the hydrogen once liquefied.
[5] For instance, estimates of the cost of hydrogen delivery and dispensing from 1,000 kg/day fueling stations indicate that, at delivery distances above ~400 miles, use of liquid tankers is more cost competitive than use of gaseous tube trailers [1].

liquid hydrogen production plants has been publicly reported to cost $150 million for a capacity of 27,000 kg/day serving the California market [2]. This industry value was used to validate and refine national laboratory cost models, and results were peer-reviewed by industry and national laboratory experts.

I. Hydrogen Liquefaction Process and Cost Estimation

Once hydrogen is produced, the conventional hydrogen liquefaction process follows the following three steps [6]:

1. Compression
2. Cooling
3. Expansion.

After compression, the temperature of the hydrogen stream is cooled to approximately 300 K. There are two steps involved in cooling. First, the hydrogen must be cooled to below its inversion temperature, approximately 80 K. This precooling step is necessary so that the temperature will decrease during expansion, which can only occur below the inversion temperature.[6] The initial cooling step typically (for capacities >3 tons/day) employs the Claude cycle with a liquid nitrogen bath and a heat exchanger.[7]

As the warm hydrogen stream flows through the nitrogen bath, the nitrogen vaporizes, cooling the hydrogen to approximately 80 K. Subsequently, the hydrogen is further cooled and ultimately liquefied through the Joule-Thomson expansion process. A second heat exchanger is used to drop the temperature of the hydrogen stream to approximately 40 K and the hydrogen is eventually expanded again to low pressure (~1.3 bar) via a throttling process.

During the throttling process, the hydrogen cools to 20 K and partially liquefies. Modern process designs use catalysts inside the heat exchangers to accelerate the ortho-to-para[8] conversion required for hydrogen liquefaction. A phase separator vessel separates the liquid from the vapor. The cold vapor is redirected to the heat exchangers to cool the inlet stream before being recycled back through the process. Figure 1 portrays the process described above.

---

[6] When hydrogen is above its inversion temperature, its temperature increases upon expansion. This phenomenon is referred to as the Joule Thomson effect.

[7] For capacities less than 3 tons/day, a helium Brayton cycle is more economical for cooling than the Claude cycle due to lower capital costs, though higher energy consumption [7]. Both the Claude cycle and the Brayton cycle use liquid nitrogen for precooling, but the Brayton cycle uses helium to drive low-cost screw compressors [8].

[8] Ortho and para refer to the orientations of the two nuclear spins in the H_2 molecule, where ortho is in the same direction and para in opposite directions. This is significant because normal, gaseous hydrogen is comprised of approximately 25% para-hydrogen and 75% ortho-hydrogen, whereas liquid hydrogen is over 99% para-hydrogen. The conversion to para (and liquid) occurs at hydrogen's boiling point (20 K), but is very slow in the absence of a catalyst [7].

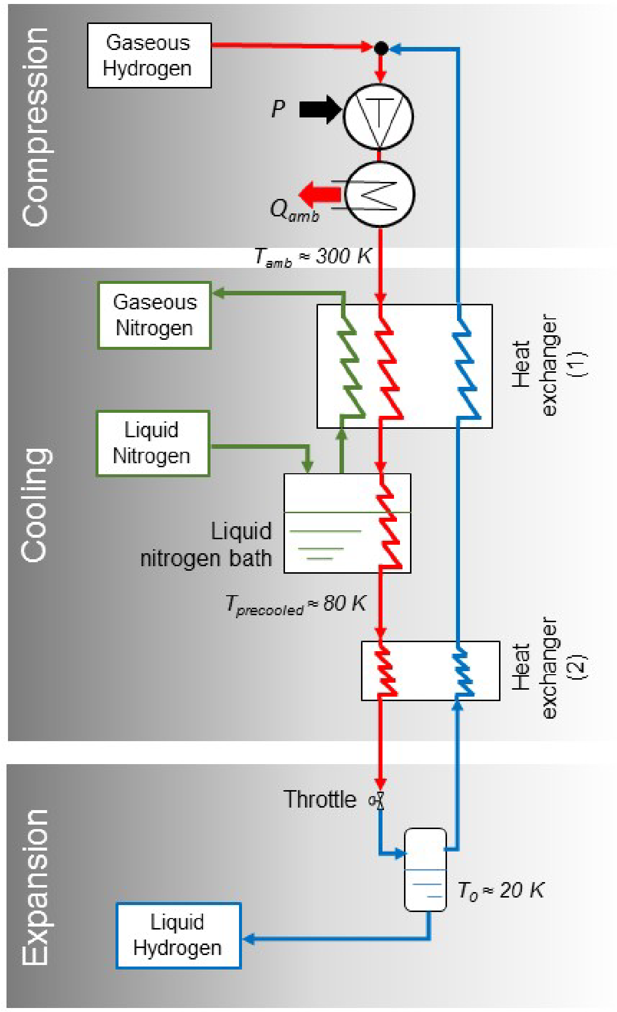

Figure 1. Joule–Thomson process with liquid nitrogen precooling redrawn based on a figure from Alekseev (2016).

The theoretical minimum energy requirement to produce liquid hydrogen, in a reversible Carnot process, is 2.88 kWh/kg, assuming an inlet pressure of 20 bar.[9] Twenty bar is the typical outlet pressure of steam methane reformers (SMR), which are primarily used to produce hydrogen for current liquefaction plants. Today's industrial liquefiers, however, have an energy requirement in the range of 10–20 kWh/kg. In this DOE Hydrogen and Fuel Cells Program Record, the Hydrogen Delivery Scenario Analysis Model (HDSAM) is used to estimate the current capital costs associated with liquefiers of varying capacities. The range of capacities considered is 6,000 to 200,000 kg/day. For reference, the smallest current U.S. liquefaction plant has a capacity of about 6,000 kg/day, and the largest a capacity of about 70,000 kg/day (to date) [9].

HDSAM evaluates the costs of current hydrogen delivery and refueling technologies for various markets and penetrations of fuel cell electric vehicles, and is updated annually with state-of-the-art performance

[9] From HDSAM v3.1, calculated using first principles.

and cost data of delivery component technologies. To determine capital costs for hydrogen liquefiers, HDSAM uses the following formula:

$$Installed\ Liquefier\ Capital\ Cost = N \times 1{,}000{,}000 \times 5.6 \times C^{\wedge}0.8 \times I$$

where,

- N is the number of liquefiers, where each liquefier can be scaled to a capacity of 200,000 kg/day (i.e., only one liquefier is needed to meet demand of less than 200,000 kg/day).
- C is the liquefier design capacity in MT/day; $5.6 \times C^{\wedge}0.8$ is the curve that best fits the data points (cost estimates) collected from various sources for different liquefier capacities.
- I is the overall Chemical Engineering Plant Cost Index (I=1.16 for the cost estimates to be presented in 2016\$).[10]

The following scenario parameters were assumed for the capital cost calculations, selected to represent a near-term early market scenario.

Table 1. Assumptions in HDSAM to represent an early market scenario.

Liquefier Analysis Period	30 years
Liquefier Lifetime	40 years
Liquefier Discount Rate	7%[11]
Production Volume for Cost Estimates	Low
Federal Tax Rate	21%

The total land cost[12] is assumed to be \$12.35/m^2. Land costs vary depending on location. The average land cost estimate, used here, was vetted by industry. Owner's costs[13] are assumed to be 12% of the installed liquefier capital cost. The total capital investment is the sum of installed liquefier capital cost, total land cost, and owner's costs.

The model results for early market liquefier capital investment are presented in the following figures. Figure 2 shows the total capital investment for hydrogen liquefiers range from \$30 million to \$490 million for capacities ranging from 6,000 kg/day to 200,000 kg/day, respectively. The trend is approximately linear. On the other hand, the capital investment per kg/day of capacity decreases as capacity increases. The reduction in capital investment by capacity, however, experiences diminishing returns with increases in capacity. For example, the cost per capacity decreases by 14% from 50,000 to 100,000 kg/day, but only by 8% from 100,000 to 150,000 kg/day.

[10] Includes cost of land associated with liquefier plant. Land costs do not include cost of SMR or liquid hydrogen terminal.

[11] 7% represents the "marginal pretax rate of return on an average investment in the private sector in recent years." Source: U.S. Office of Management and Budget, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A94/a094.pdf

[12] The land cost in HDSAM is based on a national average. The cost of land is small relative to other costs and, thus, has a small impact on the levelized cost of hydrogen.

[13] An owner's cost factor is applied for large investments to account for the funds necessary for additional owner's engineering, potential construction debt origination and closure fees, and due diligence studies. The 12% estimate is based on construction experience, as stated in HDSAM.

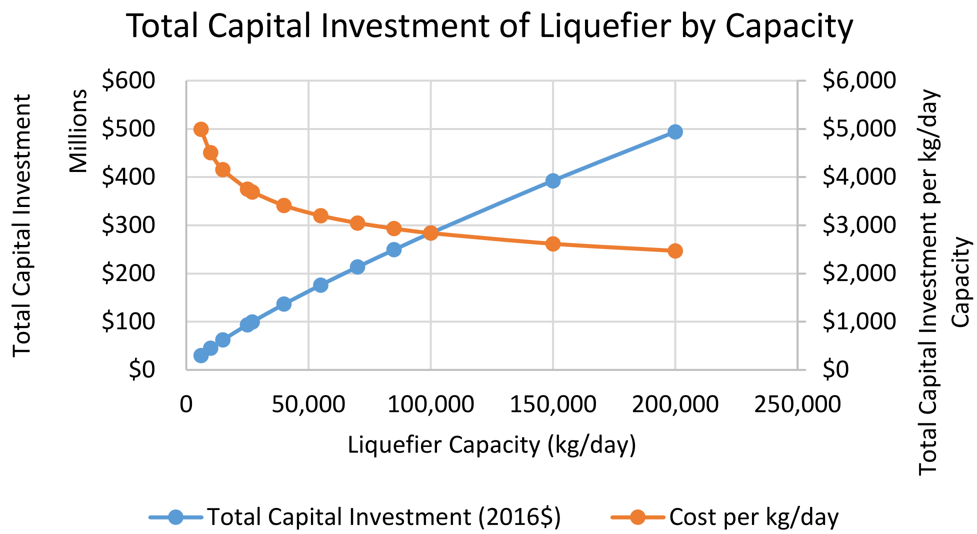

Figure 2. HDSAM results for the total capital investment of hydrogen liquefiers in an early market scenario. Results are presented in 2016$.

HDSAM estimates that the capital investment required for a 27,000 kg/day liquefier (comparable to the size announced publicly) would be about $100 million. Including capital for hydrogen production and a liquid terminal increases the capital cost to $160 million. This data demonstrates that model results from H2A and HDSAM are conservative and within 7% of industry estimates. The following section describes the methodology used to estimate capital cost for an entire liquid hydrogen supply chain, which includes hydrogen distribution and dispensing.

Figure 3 shows the liquefier capital cost contribution to the levelized cost of hydrogen with liquid delivery. The capital cost contribution of the liquefier tends to decrease as capacity increases, particularly when capacity is over 10,000 kg/day. The capital contribution is ~$1.40/kg for a liquefier with capacity of 27,000 kg/day. Additional recurring costs (e.g., electricity) result in an overall levelized cost of ~$2.75/kg total for a 27,000 kg/day liquefier. It is important to note that there are other distribution costs incurred, which are associated with the terminal and tankers used to distribute liquid hydrogen to the stations.

The capital contribution of hydrogen production via SMR to levelized cost of hydrogen is approximately $0.10/kg, and overall levelized cost of SMR is $2.24/kg; the levelized cost of production is highly dependent on the price of natural gas.[14] Figure 3 shows the calculated liquefaction energy requirement, which is also estimated to decrease with scale.[15]

[14] The capital cost contribution of SMR to the levelized cost of hydrogen also decreases as capacity increases (from $0.12/kg at 27,000 kg/day to $0.09/kg at 100,000 kg/day).
[15] This is consistent with the energy requirement range given by Ohlig and Decker (2013) [9].

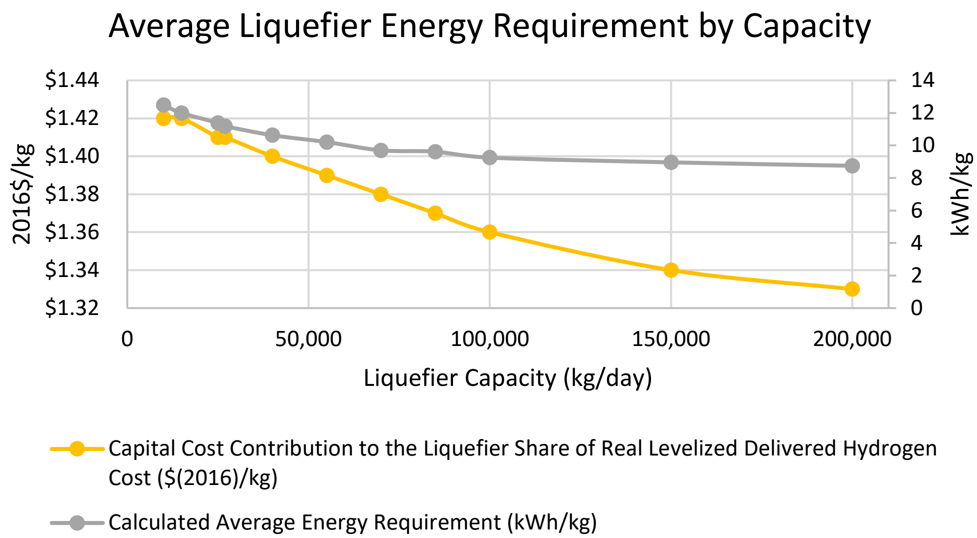

Figure 3. HDSAM results for (i) the liquefier capital cost contribution to levelized cost of hydrogen in an early market scenario (2016$) and (ii) the calculated average liquefier energy requirement (kWh/kg).

II. Liquid Hydrogen Supply Chain Cost Estimation

The majority of hydrogen production today occurs via natural gas reforming (i.e., SMR). In some states, industry is required to increase the renewable gas content of the hydrogen they produce, rather than rely solely on SMR. Industrial gas companies can increase the renewable content of their hydrogen through several approaches, including acquisition of biogas credits.

Below is an estimate of capital cost, operating expenses, and resulting prices for a vertically integrated liquefaction supply chain. This supply chain consists of hydrogen production, liquefaction, truck terminal, liquid truck delivery, and 350-kg/day liquid delivery retail refueling stations. These values were derived using the H2A model for production and HDSAM[16] for liquefaction, terminal, trucking, and retail stations. Lastly, the Hydrogen Financial Analysis Scenario Tool (H2FAST) was used to integrate the financial performance of the supply chain and to estimate the associated dispensed hydrogen cost.

Table 2 describes the capital costs associated with a 27,000 kg/day liquid hydrogen plant, including the associated terminal and SMR plant. The entire facility is modeled to cost $160 million; for reference, the industry estimate for the required capital investment for a facility of this size is $150 million. To transport and dispense this amount of hydrogen, it is estimated that at least nine tractors with liquid trailers will be needed.[17] This quantity of hydrogen could supply seventy-nine 350-kg/day refueling stations; 350-kg/day reflects the current typical size of California stations with liquid hydrogen delivery. However, it is

[16] HDSAM accounts for boil-off losses during storage at the terminal and station. All HDSAM assumptions can be found in the model available at https://hdsam.es.anl.gov/index.php?content=hdsam.

[17] The maximum capacity of liquid tankers is approximately 4,000 kg, and is limited by DOT restrictions on the allowable weight and dimensions of tankers. The number of liquid tankers also depends on the distances that the tankers are expected to travel. If a conventional liquefaction plant were assumed, rather than one exclusively supplying local (100 km radius) hydrogen fueling station demand, tankers would be expected to travel several hundreds of kilometers one-way; in that case, about 15–20 tankers would be expected to serve the plant instead.

important to note that liquefaction plants are not currently dedicated exclusively to fueling stations. Cost estimates for hydrogen delivery and dispensing from seventy-nine (79) 350-kg/day fueling stations are provided in Table 3, purely for context.

Table 2. Capital cost estimates for a 27,000 kg/day liquefaction plant (results are in 2018$)

Equipment	Capital cost, 2018$	% of total	Data source
Natural gas reformer	$ 32,000,000	20%	H2A
Liquefaction	$ 104,000,000	65%	HDSAM
Terminal total capital	$ 24,000,000	15%	HDSAM
Total capital cost	**$ 160,000,000**	**100%**	

Table 3. Capital cost estimates for the delivery and dispensing of 27,000 kg/day liquid hydrogen (results are in 2018$)

Equipment	Number of units	Capital cost, 2018$	Data source
Tractors and trailers	9 each	$ 10,000,000	HDSAM
350-kg/day stations	79	$ 181,000,000	HDSAM
Total capital cost		**$ 191,000,000**	

Figure 4 describes the breakdown of the total supply chain capital costs. Within the complete supply chain, the liquefaction plant represents approximately 45% of the capital investment for light-duty vehicle retail fueling. The capital costs of the refueling stations represent the majority of the supply chain cost, at just over 50% of the total capital cost. Increasing station capacity would reduce the number of stations needed and result in a lower total capital cost.

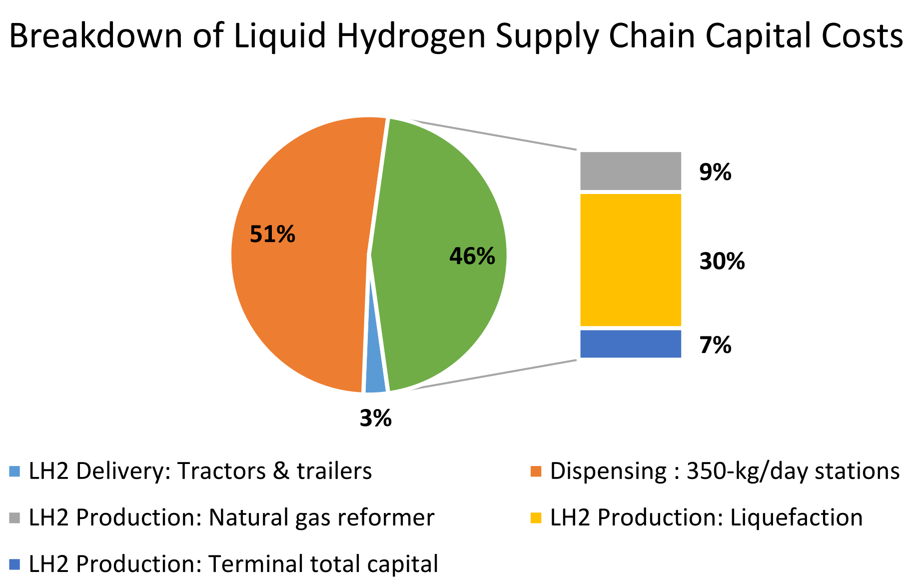

Figure 4. Breakdown of total liquid hydrogen supply chain capital costs to support 27,000 kg/day production.

III. Case Study: Liquid Hydrogen Supply Chain Cost Estimation for California Market

Additional analysis was performed for the above supply chain for the urban California market.[18] As such, energy costs for natural gas, electricity, and diesel were calibrated to California values.[19] A renewable natural gas premium of $2/MMBtu was added to all natural gas used in the plant.[20] This premium is assumed to be sufficient to secure natural gas credits from renewable sources such as landfill gas or anaerobic digester gas to address California-specific regulations. The breakdown of capital and operating costs, as well as competitive value estimates, are shown in Figure 5.

This analysis yields a profited cost of hydrogen production of $2.24/kg. Liquefaction and terminal profited costs are $2.75/kg and $0.39/kg, respectively, for a plant-gate hydrogen cost of $5.38/kg. Delivery via liquid trucks adds $0.68/kg to the cost of hydrogen and retail station costs add another $8.18/kg for a total dispensed profited cost of $14.24. Note that the largest cost component in the supply chain is the retail station. This is largely due to the relatively small modelled size of 350-kg/day, slow utilization growth (5 years), and equipment analysis period of 10 years.

A sensitivity analysis was performed to explore the cost reductions associated with assuming a larger station size. In a case with 1,000-kg/day hydrogen refueling stations, the number of liquid delivery trucks decreases. The reduction in the number of delivery trucks also reduces operating costs due to: (i) less travel and off-load time, (ii) less labor hours required, and (iii) slightly less fuel consumed. Larger stations also means that fewer are required; in this case, twenty-eight (28) 1,000-kg/day stations as opposed to seventy-nine (79) 350-kg/day stations. As a result, the station contribution to the levelized cost of hydrogen decreases by greater than $3/kg. As hydrogen infrastructure expands, larger and more economical stations would significantly reduce the cost contribution for retail stations.

---

[18] Analysis used Los Angeles–Long Beach–Anaheim to quantify energy costs and truck delivery distances. In a case where delivery distance is increased by ~200 miles to account for remote production, the number of delivery trucks would increase from 9 to 14, and diesel and labor expense would also increase, resulting in an increase in the levelized cost of dispensed H_2 cost of $0.25/kg.

[19] U.S. Energy Information Administration, https://www.eia.gov/

[20] The cost of natural gas assumes the use of approximately 33% renewable natural gas, as this is one approach to compliance with California Senate Bill 1505. Senate Bill 1505 requires that 33% of hydrogen fuel dispensed at retail stations co-funded by the State from renewable sources. The premium for California was estimated to be up to $2.00/mmBTU to achieve the 33% renewable requirement [10]. It is important to note that this requirement can also be met through other methods, and that fueling stations located in other states may not be subject to this requirement at all. The use of renewable natural gas (RNG) will depend on the market being targeted by the liquefaction plant. Further, this analysis is focused on current scenarios, and thus does not consider future scenarios with higher renewable requirements.

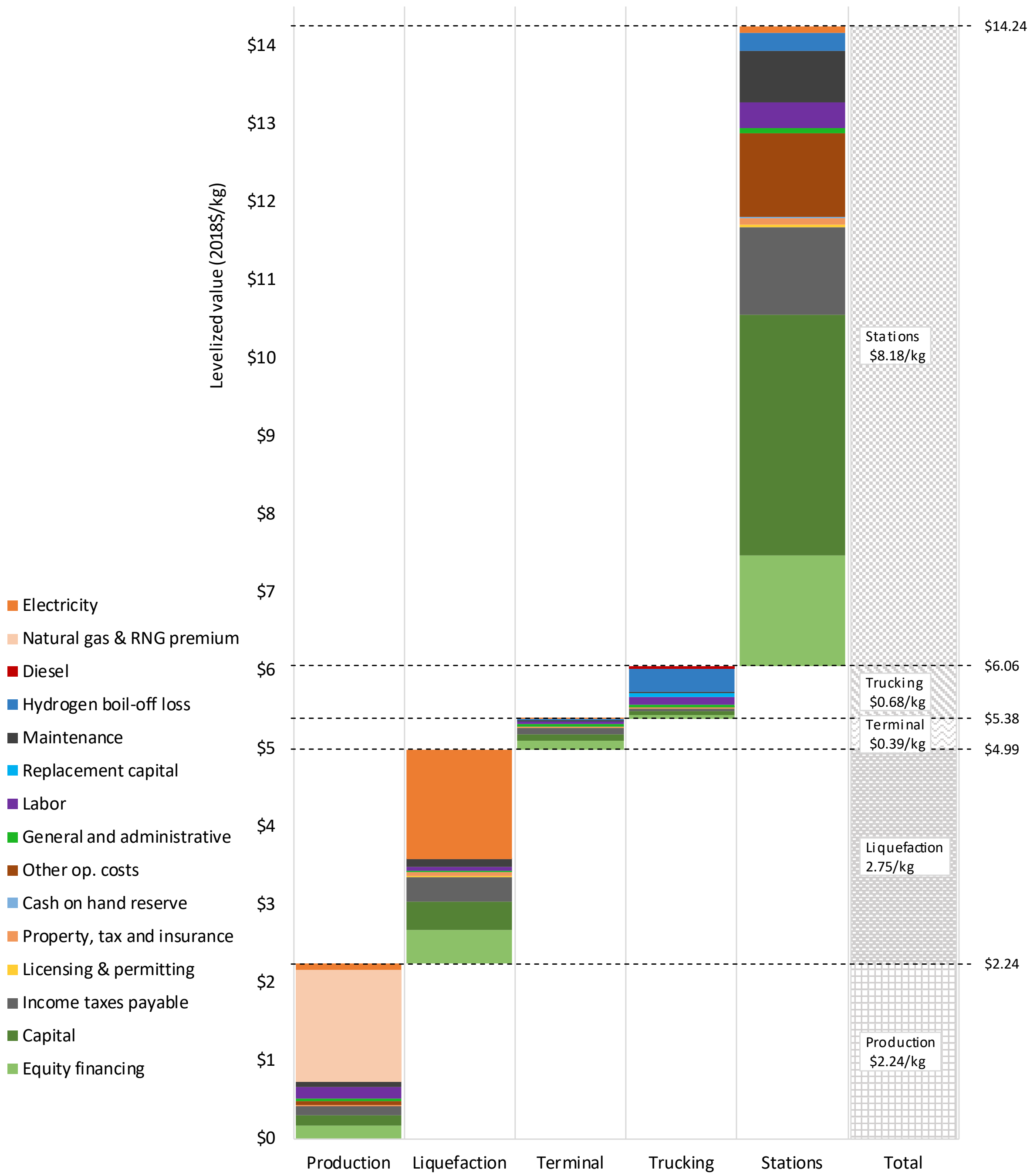

Figure 5. H2FAST supply chain financial analysis results for vertically integrated infrastructure in California. Values are reported in 2018$. Analysis assumes low volume of manufacturing of all components, 90% production utilization, 80% station utilization within 5 years,[21] and 7% rate of return. Stations are 350 kg/day with LH_2 truck delivery using cryogenic pump compression and dispensing at 700-bar for the light-duty vehicle market.

[21] Utilization rates vary widely from station to station. While it is assumed that an 80% utilization in 5 years is feasible, not all real-world stations are expected to achieve this level of growth. The utilization rate achieved per station will significantly affect the overall levelized cost of hydrogen fueling.

References

[1] Elgowainy, A. “Techno-economic Tools to Simulate the Costs of Hydrogen Infrastructure Technologies.” *Fuel Cell Technologies Office Webinar* (2018). https://www.energy.gov/sites/prod/files/2018/02/f49/fcto_webinarslides_tea_models_hdsam_hdrsam_022718.pdf

[2] Air Liquide. “Air Liquide to build first world scale liquid hydrogen production plant dedicated to the supply of Hydrogen energy markets.” November 26, 2018. https://www.airliquide.com/media/air-liquide-build-first-world-scale-liquid-hydrogen-production-plant-dedicated-supply-hydrogen-energy-markets

[3] Praxair. “Praxair to Build New Liquid Hydrogen Plant in La Porte, Texas.” November 7, 2018. https://www.praxair.com/news/2018/praxair-to-build-new-liquid-hydrogen-plant-in-la-porte-texas

[4] Air Products. “Air Products to Build World-Scale Liquid Hydrogen Plant at its La Porte, Texas Facility.” September 11, 2018. http://www.airproducts.com/Company/news-center/2018/09/0911-air-products-to-build-world-scale-liquid-hydrogen-plant-at-laporte-texas-facility.aspx

[5] Air Products. “Air Products to Build Second Liquid Hydrogen Production Facility in California.” January 7, 2019. http://www.airproducts.com/Company/news-center/2019/01/0107-air-products-to-build-second-liquid-hydrogen-productions-facility-in-california.aspx

[6] Suresh, B. et al. “Hydrogen.” IHS Markit, Chemical Economics Handbook (2018). https://ihsmarkit.com/products/hydrogen-chemical-economics-handbook.html

[7] Alekseev, A. “Hydrogen Liquefaction.” *Hydrogen Science and Engineering: Materials, Processes, Systems and Technology* (2016): 733-762.

[8] Ohlig, K. and Decker, L. “The latest developments and outlook for hydrogen liquefaction technology.” *AIP Conference Proceedings* 573 (2014): 1311. https://doi.org/10.1063/1.4860858

[9] Ohlig, K. and Decker, L. “Hydrogen Liquefaction.” *Ullmann's Encyclopedia of Industrial Chemistry* (2013). Wiley-VCH Verlag GmbH & Co. KGaA.

[10] Jaffe, A., Dominguez-Faus, R., Parker, N., Scheitrum, D., Wilcock, J., and Miller, M. “Policy Brief – Renewable Natural Gas Provides Viable Commercial Pathway for Sustainable Freight.” (September 2017). https://steps.ucdavis.edu/wp-content/uploads/2017/10/RNG-policy-brief-FINAL-WITH-ABSTRACT-Sep2017.pdf