Joint Agency Staff Report on Assembly Bill 8: Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California

California Energy Commission

California Air Resources Board

Edmund G. Brown Jr., Governor

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PREFACE

Assembly Bill 8 (AB 8, Perea, Chapter 401, Statutes of 2013) directed the California Energy Commission to allocate up to $20 million annually from the Alternative and Renewable Fuel and Vehicle Technology Program for development of light duty hydrogen refueling stations for fuel cell electric vehicles (FCEVs). AB 8 also directed the Energy Commission and California Air Resources Board (ARB) to conduct a series of annual assessments; the ARB is charged with assessing the progress of hydrogen station development in terms of geographic coverage and fueling capacity, and with assessing the number FCEVs being deployed by automakers in California. The ARB has produced two such reports, the most recent being the *2015 Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development.*

AB 8 further directs the Energy Commission and ARB to determine the remaining cost and timing to establish a network of 100 publicly available hydrogen refueling stations. This *Joint Agency Staff Report on Assembly Bill 8: Assessment of Time and Cost to Attain 100 Hydrogen Refueling Stations in California* represents the investigation and findings into estimated costs and timing to reach the 100-station milestone established in AB 8.

This report is a companion report to the ARB assessments. Taken together, these complementary reports provide ongoing assessments of the hydrogen station network and numbers of FCEVs sold in California.

ABSTRACT

The *Joint Agency Staff Report on Assembly Bill 8: Assessment of Time and Cost Needed to Attain 100 Hydrogen Fueling Stations in California* is the California Energy Commission's and California Air Resources Board's first joint report on how much time and public incentive funding through the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) will be needed to reach the 100 station milestone in California in accordance with Assembly Bill 8 (AB 8). The report assesses the time needed to date to develop the first 49 stations funded by the Energy Commission and finds that overall hydrogen refueling station development timelines have decreased from an average of 4.9 years for 5 stations funded in 2009 to 1.6 years for 6 stations funded in 2013 that have achieved operational status. The report finds that costs for early market hydrogen refueling stations are high and range from $2.1 million to more than $3 million for 180 kilogram-per-day (kg/day) and 350 kg/day stations, respectively. Equipment costs are not expected to decrease significantly in the near term but have the potential to decrease by 50 percent through 2025. Energy Commission incentive funding levels range from 70 to 85 percent of total capital costs and are expected to be needed to be sustained for the next several years to reach the 100 station target. To date, Energy Commission incentive funding totals $80.9 million in capital cost support and $9.9 million in operating and maintenance cost support. Private sector capital match funding to date totals nearly $35 million. Ongoing incentive funding will be needed to support development of the 100 hydrogen refueling stations specified in AB 8. The report concludes that California will attain the 100-hydrogen-refueling-station milestone goal between 2020 and 2024 (consistent with the timeline for AB 8, which expires in 2023), depending on market conditions and consumer response to FCEVs, and that $157 million to $170 million in cumulative ARFVTP incentive funding will be needed.

Keywords: California Energy Commission, California Air Resources Board, Alternative and Renewable Fuel and Vehicle Technology Program, AB 8, hydrogen, hydrogen refueling station, hydrogen costs, hydrogen fuel prices, fuel cell electric vehicle, incentive funding, National Renewable Energy Laboratory.

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EXECUTIVE SUMMARY

Assembly Bill 8 (AB 8, Perea, Chapter 401, Statutes of 2013) reauthorized Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) and created new legal requirements for the California Energy Commission's (Energy Commission's) Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP or Program), which creates an annual $100 million public investment fund to promote development and deployment of advanced technology, low carbon fuels and vehicles that will help the state achieve its greenhouse gas reduction goals. AB 8 directs the Energy Commission to allocate up to $20 million, or up to 20 percent of each fiscal year's available funding, for the development of hydrogen refueling stations (HRS) until there are at least 100 publicly available hydrogen-fueling stations in operation in California (Section 43018.9[e]).

AB 8 directs the California Air Resources Board (ARB) to report annually on the current and expected number of hydrogen fuel-cell vehicles in California and to evaluate and report to the Energy Commission the need for additional hydrogen refueling stations to meet vehicle demand. The ARB has published two such reports; the most recent is the *2015 Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development.*

In addition, the bill also directs ARB and the Energy Commission to annually "jointly review and report on progress toward establishing a hydrogen-fueling network that provides the coverage and capacity to fuel vehicles requiring hydrogen fuel that are being placed into operation in the state," including determining "the remaining cost and timing to establish a network of 100 publicly available hydrogen-fueling stations and whether funding from the Alternative and Renewable Fuel and Vehicle Technology Program remains necessary to achieve this goal." This joint report assesses progress toward building an initial network of stations, evaluates ability of the program to serve hydrogen fuel cell vehicles now and in the future and estimates the funding support required to reach 100 stations.

The Energy Commission contracted with the National Renewable Energy Laboratory (NREL) to analyze the time and cost needed to attain 100 hydrogen refueling stations in California. NREL conducted both a scenario analysis and financial analysis to develop a range of time and cost estimates that illustrate various consumer responses and market development projections for FCEVs in California. These initial scenario estimates are based on available data for station costs, hydrogen fuel prices and levels of FCEV adoption in California. The analyses will be updated in future years to incorporate new market information.

Summary of Findings

The Energy Commission and Air Resources Board have developed eight findings to represent the results of the analyses conducted for this joint review based on information available through December 2015. Subsequent annual reports will continue to assess the applicability of these findings and provide new findings as appropriate given new lessons and information gathered as the hydrogen fueling station network grows in California.

In 2016, more than 50 hydrogen refueling stations will be open with capacity for more than 10,000 FCEVs. Future demand could outpace capacity by 2020-2021, demonstrating that continued state financial support for hydrogen refueling stations is critical to enabling steady market growth for FCEVs in California.

According to the December update to ARB's June 2015 AB 8 Report, *2015 Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development*, Department of Motor Vehicles registrations and automaker announcements indicate that there will be 300 fuel cell electric vehicles (FCEVs) registered in California by the end of 2015. According to the ARB survey of FCEV automakers, 10,500 FCEVs are projected in California by the end of 2018, and 34,300 by the end of 2021. Two automakers, Hyundai and Toyota, offer FCEVs for commercial lease or sale, and Honda has announced plans to introduce FCEVs to California in 2016. Several other automakers are developing fuel cell products with plans to commercialize in the coming years.

Of the 49 new or upgraded hydrogen refueling stations funded by Energy Commission ARFVTP to date, 10 are operational, and all 49 are expected to be open for retail hydrogen fuel sales in 2016. Several small capacity technology demonstration hydrogen fueling stations funded in the 2000s are also operational, but many will be upgraded or closed due to small capacity. In total, up to 51 modern stations—with a total expected capacity of more than 9,500 kilograms per day in fueling capacity —are expected to be open for retail sales in 2016.

This initial network will provide enough capacity to fuel more than 10,000 FCEVs, but it is imperative that California continue to support hydrogen station development with AB 8 incentive funding to ensure that new FCEV customers have access to a convenient, reliable, and continuously expanding network of hydrogen refueling stations. Automakers will bring the projected number of vehicles to market only if sufficient hydrogen station coverage and capacity exists.

Given the current pace of station rollout and expected vehicle demand, an initial network of 100 stations is expected to be complete by 2020 and is anticipated to require about $160 million in public incentive funding.

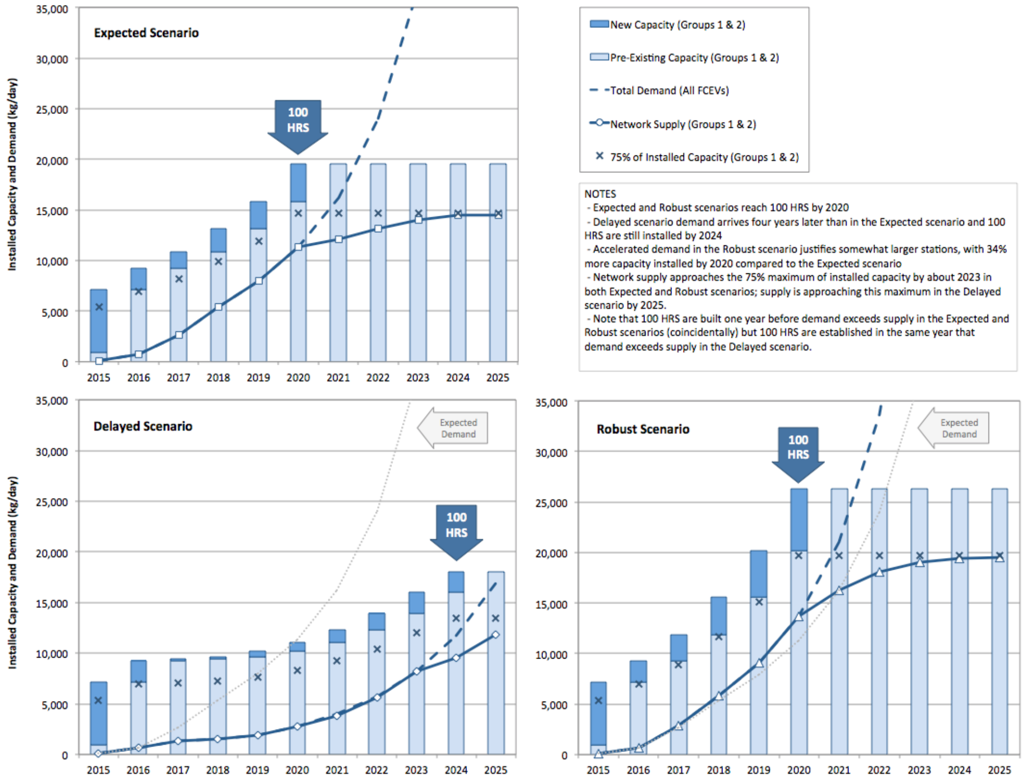
As of December 2015, the Energy Commission ARFVTP has provided $80.9 million in capital incentive funding for 49 new or upgraded hydrogen refueling stations in California and $9.9 million for operations and maintenance support. Private sector matching investments total nearly $35 million. The pace of FCEV adoption by consumers affects the amount of public and private investment needed to develop the network, which affects total network deployment cost and timing. To model the resulting range of effects, the NREL analytic team developed and analyzed three scenarios for early market HRS development in California and developed a range of time and cost estimates to reach 100 hydrogen fueling stations.

Expected Scenario:

Assuming FCEV adoption occurs as projected in the ARB assessment, 100 HRS are expected to be developed by 2020 with a network capacity of a little more than 19,500 kg/day. Total AB 118 and AB 8 funding needed to support this scenario is roughly $160 million. The Energy

Commission would invest AB 8 funds through 2020 to reach 100 hydrogen refueling stations. Demand for additional station coverage and capacity is expected beyond 100 stations, and ARFVTP investments will continue to be important to develop a self-sustaining network. Total market value of the hydrogen fuel sold to meet demand could range from $80 million in 2021 to more than $400 million in 2025.

Figure ES-1: Comparison of Three HRS Development Scenarios in California to Reach 100 Stations



Note: Group 1 denotes the first 51 stations funded to date and Group 2 denotes the next 49 stations needed to reach 100 HRS.
Source: NREL

Delayed Scenario:

If FCEV adoption were to occur more slowly than projected by ARB, due to unforeseen delays in network development or poor consumer response to FCEVs, the Energy Commission would slow the pace of station development beginning in 2018-2019. Assuming FCEVs sales are delayed by four years beyond those projected in the ARB assessment, the 100 station target would be reached in 2024. Lower annual levels of ARFVTP funding would be allocated between 2019 and 2023, and a total of $170 million would be needed to reach the 100 hydrogen refueling station milestone with a smaller network capacity of 16,000 kg. The market value of the fuel sold to meet demand in the 2024 to 2025 period could range from $70 million to $80 million.

Robust Scenario:

If FCEV adoption occurs more rapidly than projected, additional private capital would likely be invested into the hydrogen refueling station network, allowing 100 hydrogen fueling stations to be developed by 2020 with a total fueling capacity of 26,000 kg/day, which would be substantially larger than the Expected Scenario. Total AB 118 and AB 8 funding needed to support this scenario would be roughly $160 million. As with the Expected Scenario, demand for additional station coverage and capacity would continue beyond 100 stations, and ARFVTP investments would continue to be important to develop a self-sustaining network. Total market value of the hydrogen fuel sold to meet demand could range from $100 million in 2021 to more than $800 million in 2025.

Significant improvements have been made in station development timelines.

Overall station development time has reduced significantly between the first round of ARFVTP-funded stations in 2009 to the current round of stations funded in 2013. Stations funded in 2009 are requiring an average of 1737 days (4.9 years) to become operational, while the stations funded in 2013 are requiring only 610 days (1.6 years) (based on the six operational stations to date) (Table ES-1). This 1.6-year average for the highest performing stations funded in 2013 indicates the new efficiency and vitality that hydrogen refueling station developers are bringing to California. Several key factors for improving HRS development timelines include:

- Higher levels of public capital funding and operations and maintenance funding for stations that could be built and opened quickly.
- Establishment of the ZEV Infrastructure Manager position at the Governor's Office of Business and Economic Development to assist with local permitting issues.
- Introduction of a dispenser certification system to certify new hydrogen refueling station dispensers to sell hydrogen as a motor vehicle fuel.
- Significant reductions in permitting times.

However, some remaining challenges continue to delay station development. The biggest factor in HRS development delays comes from the loss of the initially proposed station site.

Hydrogen station costs are expected to begin declining around 2020 and could decrease by 50 percent in 2025 due to increased worldwide demand for HRS.

Current costs for hydrogen fueling stations in California range from $2.1 million to more than $3 million per station. This is still an early, developing market. These costs are due to the low production volumes of specialized equipment required for the high pressure, temperature-controlled fueling standards developed by the automotive industry for passenger car fueling. At present, government incentives are needed for 70 to 85 percent of the capital equipment costs for new hydrogen refueling stations, as well as ongoing subsidies for operations and maintenance costs.

Major reductions in equipment and station development costs are unlikely for the next set of 49 hydrogen refueling stations needed to reach 100 hydrogen stations in California because it is unlikely that orders of this scale would be large enough to trigger economy-of-scale cost reductions in fabrication and production plants; most orders will continue to be small and assembled by hand. Over the longer term, more efficient installation practices, greater economies of scale for larger stations, higher volumes in equipment manufacturing, and increased market competition hold strong potential for cost reductions. Assuming continued growth in the California FCEV refueling market coupled with hydrogen refueling stations development in Europe, Asia and other parts of the United States, hydrogen refueling stations equipment and installation costs could decline by materially by 2025.

Table ES-1: Average Time for Each Hydrogen Refueling Station Development Phase for Three Energy Commission Funding Solicitations

Energy Commission Grant Solicitation	NOPA to Business Meeting (days)	Business Meeting to Grant Execution (days)	Grant Execution to Permit Application (days)	Permit Application to Approval to Build (days)	Approval to Build to Operational (days)	Total Average Time become Operational (days)	No. of Stations with Site Change	Operational to Open for Retail (days)
PON-09-608	**224**	**219**	**853**	**255**	**186**	**1,737**	*7*	**202**
	10 of 10 stations	*10 of 10 stations*	*9 of 10 stations*	*7 of 10 stations*	*5 of 10 stations*			*4 of 10 stations*
PON-12-606	**62**	**56**	**556**	**391**	**N/A**	**TBD**	2	**NA**
	7 of 7 stations	*7 of 7 stations*	*6 of 7 stations*	*2 of 7 stations*	*0 of 7 stations*			*0 of 7 stations*
PON-13-607	**82**	**14**	**188**	**196**	**130**	**610**	6	**63**
	28 of 28 stations	*28 of 28 stations*	*23 of 28 stations*	*18 of 28 stations*	*6 of 28 stations*			*1 of 28 stations*
Total	**45**						**15**	

Source: California Energy Commission

Leveraging private investments has accelerated station development.

Given the current public investment rate of $20 million a year, and the average cost of station development and operation and maintenance assistance, the Energy Commission is able to fund about seven new stations per fiscal year. Leveraging private funds can augment the number of stations that can be supported for each public dollar invested, and indeed this is already occurring.

In 2014, Toyota's investment in FirstElement Fuel, Inc., a new station integrator, enabled it to make a bid for a network of 19 stations that was about $500,000 less per station than other applicants. This in turn allowed the State of California to obtain seven additional stations than if FirstElement had bid at the maximum level of $2.1 million per station. Toyota and Honda have announced additional investments in station development companies in California and Toyota has announced an agreement with Air Liquide, an industrial gas supplier, to develop hydrogen refueling stations on the East Coast. Private capital investment from outside the automotive and industrial gas industries, however, is unlikely until the potential for higher gross margins and internal rates of return are apparent to commercial banks or investment firms.

Future hydrogen fuel prices could drop to make the cost of operating a hydrogen vehicle more competitive.

Hydrogen fuel prices range from $12.85 to more than $16 per kilogram (kg), but the most common price is $13.99 per kg (equivalent on a price per energy basis to $5.60 per gallon of gasoline), which translates to an operating cost of $0.21 per mile. Automakers are including three years of hydrogen fuel with their initial sales and lease offerings, which will shield early market adopters from this initially high fuel price.

While future price is uncertain, NREL estimates that hydrogen fuel prices may fall to the $10 to $8 per kg range in the 2020 to 2025 period. A kilogram of hydrogen has about the same energy content as a gallon of gasoline. FCEVs are about twice as efficient as gasoline-powered vehicles: an FCEV travels about twice as far as a conventional vehicle given the same amount of fuel energy. At $3.50 per gallon gasoline, a conventional vehicle costs about $0.13 per mile to operate, while an FCEV using $8 per kg hydrogen fuel would cost about $0.12 per mile.

Improving the value proposition of FCEVs by reducing the cost of ownership, including fuel price, may be a determining factor in the success of the hydrogen and FCEV markets, ultimately reducing the cost to the State for the initial hydrogen network.

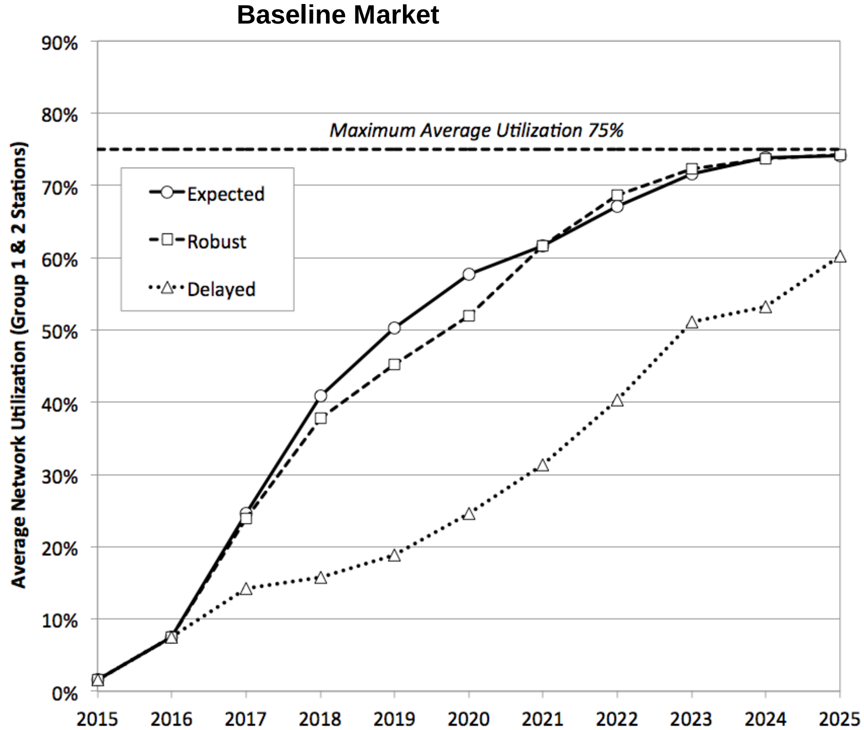
Continued public investment is required in the near term until a business case exists for non-subsidized station development.

Hydrogen fueling stations will require ongoing government incentive support and new private investment for many years until sufficient numbers of fuel cell electric vehicles are available in California to generate the volume of hydrogen fuel sales required to create positive revenues for station developers and operators. Given current levels of FCEVs and hydrogen refueling stations this first group of 51 early market hydrogen stations is projected to operate at very low capacity utilization rates between 2015 and 2017 and are not likely to attain the 75 percent average utilization rates needed to begin generating positive cash flows until 2023-2025 (Figure ES-3).

According to NREL's financial analysis using the H2FAST modeling tool, a 180 kg-per-day station with no government funding support, which opened in 2018 when 10,500 FCEVs are projected in California, would not attain a positive cash flow over the 20-year life of the station, even if it charged $16 per kg of fuel. However, if this same hypothetical station were to receive the current levels of Energy Commission incentive funding when it opened in 2018, it could attain a positive cash flow as early as 2020 while selling hydrogen at $9.50 per kg. As hydrogen demand grows within urban markets, larger and more profitable stations can be developed and sustained, which would, in turn, attract new private capital.

Because of these low early market revenue projections, the Energy Commission has shifted up to $5 million per year from capital cost support to operations and maintenance cost support to ensure that early market HRS have sufficient revenues to remain viable and open until there are enough FCEVs and customers to generate positive revenues from hydrogen fuel sales. Providing the operations and maintenance cost support has increased developer interest in building the early stations and resulted in more proposals in response to the most recent solicitation.

Figure ES-2: Projected Average Hydrogen Refueling Station Utilization Rate under Current Baseline Market Conditions



Source: NREL

CHAPTER 1: Introduction

Hydrogen fuel cell electric vehicles (FCEVs) and hydrogen refueling stations (HRS) are expected to play key roles in California as the state transitions to lower-carbon and zero-emission vehicle (ZEV) technologies for light-duty passenger vehicles, transit buses, and truck transport fleets. Numerous government regulations and policy actions identify FCEVs as a vehicle technology that will be available to meet the California Air Resources Board (ARB) Zero Emission Vehicle Regulation (ZEV Regulation) and the Governor's Zero Emission Vehicle Mandate (ZEV Mandate). More specific actions to bring FCEVs to California markets are specified in the Governor's *Zero Emission Vehicle Action Plan (ZEV Action Plan)*.

Hydrogen fuel cell electric drive technology offers tremendous potential for the light-duty passenger vehicle market and medium- and heavy-duty truck and bus markets. FCEV passenger vehicles can drive more than 300 miles on a tank of hydrogen and can be refueled in 3 to 4 minutes the way gasoline passenger vehicles are fueled. They have zero tailpipe emissions, while carbon footprint of these vehicles is nearly the same as plug-in electric vehicles.[1] The technology can be readily scaled up for SUVs, family passenger vans, pick-up trucks, urban package and beverage delivery trucks, and even heavy-duty trucks and buses. The greatest potential for fuel cells is expected in the larger vehicle categories, where zero emissions are sorely needed and battery use is constrained. Two public transit fleets in California have been operating fuel cell electric buses since 2000. Most auto industry analysts and agencies view fuel cell electric drive technology as a complement to battery electric drive technologies, rather than as a competing technology.[2] Both battery and fuel cell electric vehicle technologies will be needed in California to achieve the ZEV deployment goals.

In contrast to battery electric and plug-in hybrid electric vehicles that can be charged in home settings, FCEVs require a new network of fueling stations for normal consumer use. This has meant that the auto industry and station development industry have had to co-develop two new technologies in parallel: hydrogen refueling infrastructure and hydrogen fuel cell electric vehicles. Automakers cannot begin widespread commercial sales without a minimum network of stations, while station developers have to manage timing and costs so that the initial network of stations doesn't open and sit idle with a negative revenue stream due to a lack of customers. This has proved challenging for both industries.

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1 Assuming that all hydrogen sold through public funded HRS in California contains one-third renewable hydrogen in accordance with SB 1505, electricity offers a 70 percent reduction and hydrogen offers a 65 percent reduction, in carbon emissions from the petroleum baseline.

2 *A California Roadmap: The Commercialization of Fuel Cell Electric Vehicles,* California Fuel Cell Partnership, 2012.

Assembly Bill 8 (AB 8, Perea, Chapter 401, Statutes of 2013) reauthorized the original AB 118 funding program (Núñez, Chapter 750, Statutes of 2007) and created new legal requirements for the California Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP). The bill directs the Energy Commission to allocate up to $20 million, or up to 20 percent of each fiscal year's available funding, for the development of hydrogen refueling stations "until there are at least 100 publicly available hydrogen-fueling stations in operation in California" (Health and Safety Code 43018.9[e][1]).

Table 1 shows the Energy Commission's progress toward the 100 HRS directive. The Energy Commission has developed and awarded three main funding solicitations since the program began issuing grants in 2009, plus an upgrade grant to the South Coast Air Quality Management District (SCAQMD).

Table 1: Summary of Energy Commission Solicitations and Award Dates

Solicitation No.	NOPA Date	Total Capital Funding ($ millions)	Number of HRS Developers Awarded	Number of Stations Funded
PON-09-608	November 2010	15.7	2	10[2]
PON-12-606	April 2013	11.9	4	7
PON-13-607	May 2014	46.6	8	28[3]
South Coast Upgrades	August 2013[1]	6.7	3	4
		80.9		49[4]

Source: California Energy Commission

[1] Exempt agreement between the Energy Commission and South Coast AQMD
[2] Although 11 stations were funded in 2010, one was canceled.
[3] 28 stations were funded plus a mobile refueler.
[4] Final count of Energy Commission-funded HRS through 2015 is 49 stations

AB 8 also directs the Air Resources Board to "report on progress toward establishing a hydrogen-fueling network that provides the coverage and capacity to fuel vehicles requiring hydrogen fuel that are being placed into operation in the state" (Section 43018.9[e][6]). This assessment includes an annual survey of automakers on their plans to deploy FCEVs in California and identifies the areas across the state where new infrastructure is most needed to support FCEV adoption and fueling needs. The ARB has published two such reports in response to AB 8. The most recent is the *2015 Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development.*[3]

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3 *2015 Annual Evaluation of Fuel Cell Vehicle Deployment and Hydrogen Fuel Station Network Development*, July 2015, California Air Resources Board Staff Report.

AB 8 further directs the Energy Commission and ARB to "determine the remaining cost and timing to establish a network of 100 publicly available hydrogen refueling stations and whether funding from the Alternative and Renewable Fuel and Vehicle Technology Program remains necessary to achieve this goal" (Health and Safety Code 43018.9[e][6]). This report represents the Energy Commission's investigation and findings into estimated costs and timing to reach the 100-station milestone in California. It has been authored in consultation with ARB.

Report Approach and Method

To estimate the time and cost needed to reach the 100-station milestone for HRS in California, this report first establishes a baseline condition by documenting the time and cost needed to reach the current set of 51 HRS. The analysis focuses primarily on the modern technology stations funded by the Energy Commission, but also documents the time and cost needed to develop the initial fleet of technology demonstration stations. The Energy Commission obtained data by reviewing its program files and by conducting follow-up interviews with HRS developers. The scenarios for future potential cost reductions were developed in collaboration with the National Renewable Energy Laboratory (NREL).

ARB Update of June 2015 AB 8 Findings on FCEV Deployment

In accordance with AB 8, ARB provides an update on its FCEV deployment projections and hydrogen station development status. Key figures from the June 2015 report are also provided here for reference.

Hydrogen Station Development Timelines

Chapter 3 of the report examines the time required to develop retail HRS in California that can be easily used by the public. The timeline begins with the announcement of an Energy Commission ARFVTP funding award (Notice of Proposed Award, or NOPA), and culminates with the announcement that a station is open for business. Key milestones in the station development timeline include execution of the ARFVTP grant award, finalization of the commercial lease agreement, HRS site design and engineering, pre-application outreach to the permitting jurisdiction, permitting and planning review, planning approval, approval to build, construction, final inspection, commissioning, initial operations, and open for public retail business. In response to stakeholder concerns about the slow pace of HRS development in California, the State created a new position of ZEV Infrastructure Manager, funded by the Energy Commission, within GO-Biz in 2014 to help alleviate permitting issues. This section documents the issues and time associated with HRS development, the government and stakeholder strategies to shorten and streamline the time required to develop and permit a HRS, and a future estimate for HRS development in California. It uses data and information from Energy Commission project files, the ARB, and from the SmartSheet Tracking Tool[4] developed by the Governor's Office of Business and Economic Development (GO-Biz).

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4 GO-Biz uses a publicly available tracking system called Smartsheet™ to track the progress of HRS development in California to provide a timely and consistent set of information to interested stakeholders.

Hydrogen Station Development Costs

Chapter 4 of the report documents the historical and current costs to develop and operate a modern technology HRS in California. It begins with a detailed cost analysis of the three predominant technology systems used by station developers in California: delivered high-pressure gaseous systems, delivered liquid hydrogen systems, and on-site generation of hydrogen using electrolysis. The Energy Commission has contracted with the National Renewable Energy Laboratory (NREL) to analyze the time and cost needed to attain 100 HRS in California.[5]

Using the Scenario Evaluation, Regionalization and Analysis (SERA) and Hydrogen Financial Analysis Scenario Tool (H2 FAST) modeling tools that have been developed by NREL for the U.S. Department of Energy, the report assesses the potential for lower station costs through improvements in economies of scale, technology innovation, larger station sizes, industry lessons and increased market competition as more companies compete to develop new HRS in California. The NREL analyses will serve as a template for future national level assessments for H2USA, a national public-private consortium of eight automotive companies, various industry partners, and state and federal agencies working to advance the deployment of FCEVs and hydrogen fueling infrastructure throughout the United States. The state of California joined H2USA in 2014.

Consultation with ARB staff and station developers provide critical information and perspective. Cost data were obtained from ARFVT Program files, stakeholder consultation, public reports, and academic literature.

Three types of costs are analyzed in this report. First is the total cost to install and operate a HRS. These are the "all in" costs borne by the station development company to bring a modern technology HRS to market. Second is the cost to the public and California government to subsidize early market station development through grants and other incentive programs. Third is the cost to the consumer, which is reflected in the retail sale price of hydrogen fuel.

In Chapters 5 and 6, the report concludes with an assessment of future potential costs to develop the estimated 50 stations required to bring the network to a total of 100 HRS, as well as additional stations that may be required through the 2025 to 2030 time frame. These potential future costs are described in three scenarios that include the current cost and timing situation and variations with a more and less optimistic projection for the pace of FCEV and HRS market growth. These variations capture the potential changes to the outlook due to a number of conceivable factors, including: various levels of increased private investment and better financing opportunities, reduced public investment, increased economies of scale, larger station sizes and reductions in equipment costs through increased competition, standardization of design, and technology innovations.

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5 The National Renewable Energy Laboratory conducted the work for the Energy Commission under Cooperative Research and Development Agreement 600-11-002.

The time needed to develop a HRS network that provides the coverage and capacity needed to fuel FCEVs expected between 2015 and 2025 will be largely a function of station costs and combined public and private investments as more stations are developed per increment of the $20 million in annual State of California funding made available through ARFVTP.

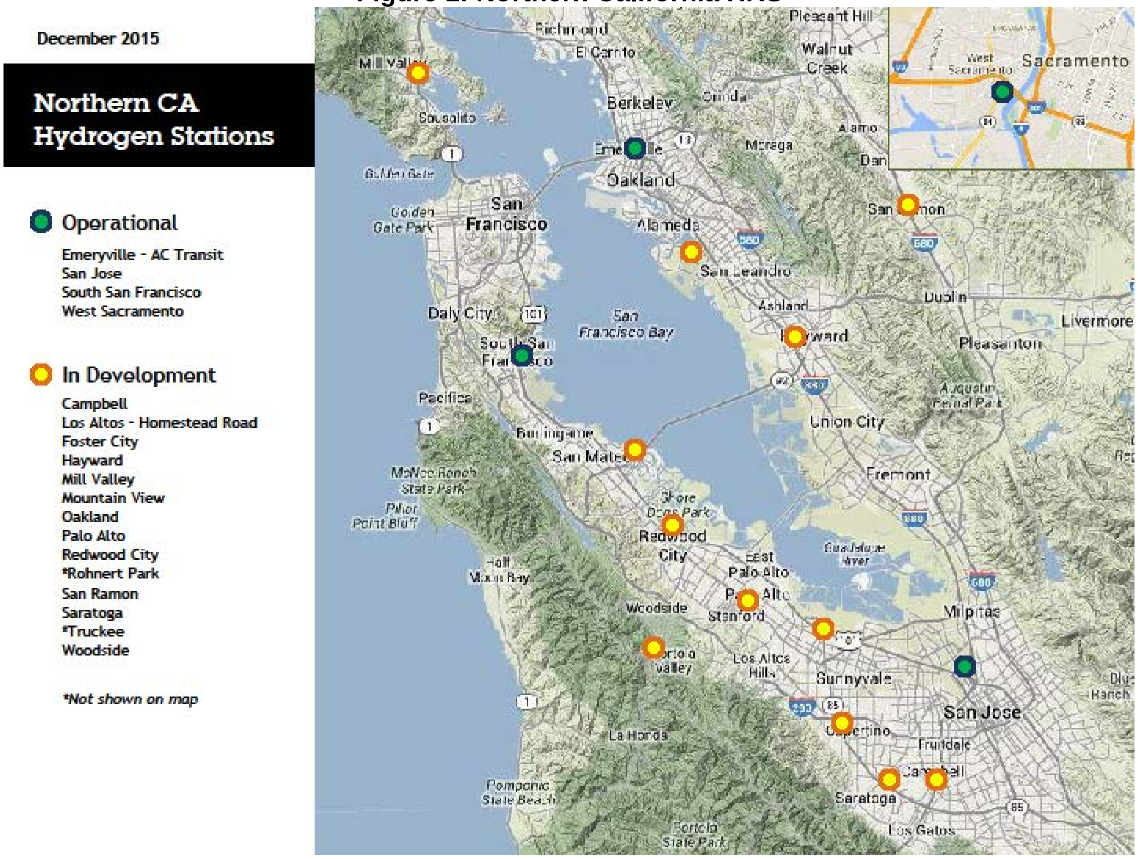
CHAPTER 2: Station Status and Fuel Cell Electric Vehicle Deployment

As of December 2015, California has provided funding for a cumulative total of 53 hydrogen fueling stations[6] that are operational or expected to be operational in 2016 to fuel light-duty FCEVs. The Energy Commission's ARFVTP has provided more than $100 million in total funding for hydrogen station development support with $80.9 million being invested specifically for 49 new or refurbished publicly available HRS that meet the current modern technical standards for pressure and temperature controls (SAE J2601 fueling protocol), fuel quality (SAE J2719 fuel quality standard), and average daily capacity.

The California Energy Commission is supplementing the capital grant incentives with operations and maintenance funding grants for 33 stations totaling $9.9 million. The HRS development industry has invested nearly $35 million in matching capital costs for the 49 stations, as well as many more millions in HRS equipment technology development. The ARB provided $15.7 million in funding for eight technology demonstration stations under the Hydrogen Highway Program of the early 2000s. These stations are now operational, but some will be refurbished to current technical and capacity standards with ARFVTP funding. A few demonstration stations may be closed and decommissioned. Figures 1 and 2 depict the locations of the 53 hydrogen stations in Northern and Southern California.

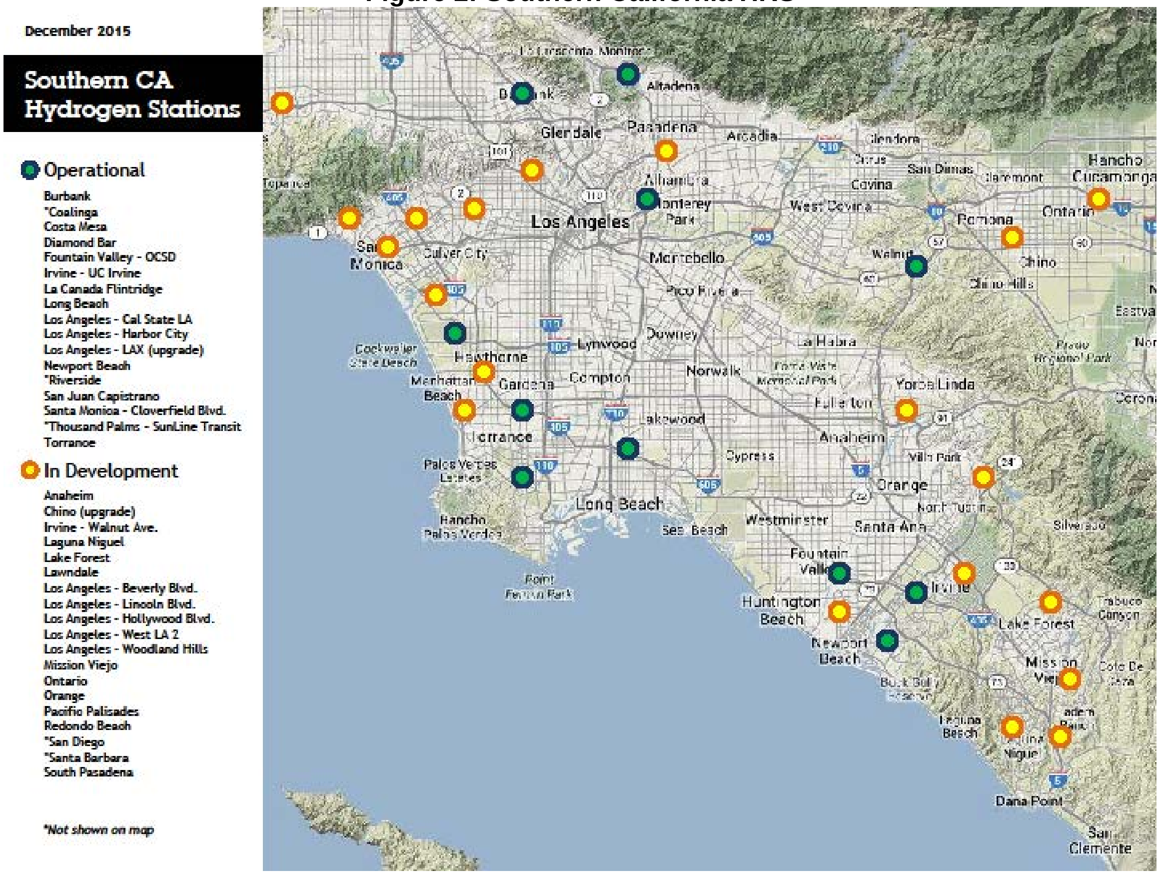
6 The 53 stations include two with uncertain futures: Fountain Valley station at the Orange County Sanitation District no longer functions as a tri-generation station and has been temporarily reconfigured to supply hydrogen using tube trailer deliveries for one year. The Emeryville AC Transit site offers limited fueling for FCEVs, but is slated for a potential equipment upgrade from the now canceled Oakland Airport site.

Figure 1: Northern California HRS



Source: California Fuel Cell Partnership

Figure 2: Southern California HRS



Source: California Fuel Cell Partnership

FCEVs Anticipated (2015-2021)

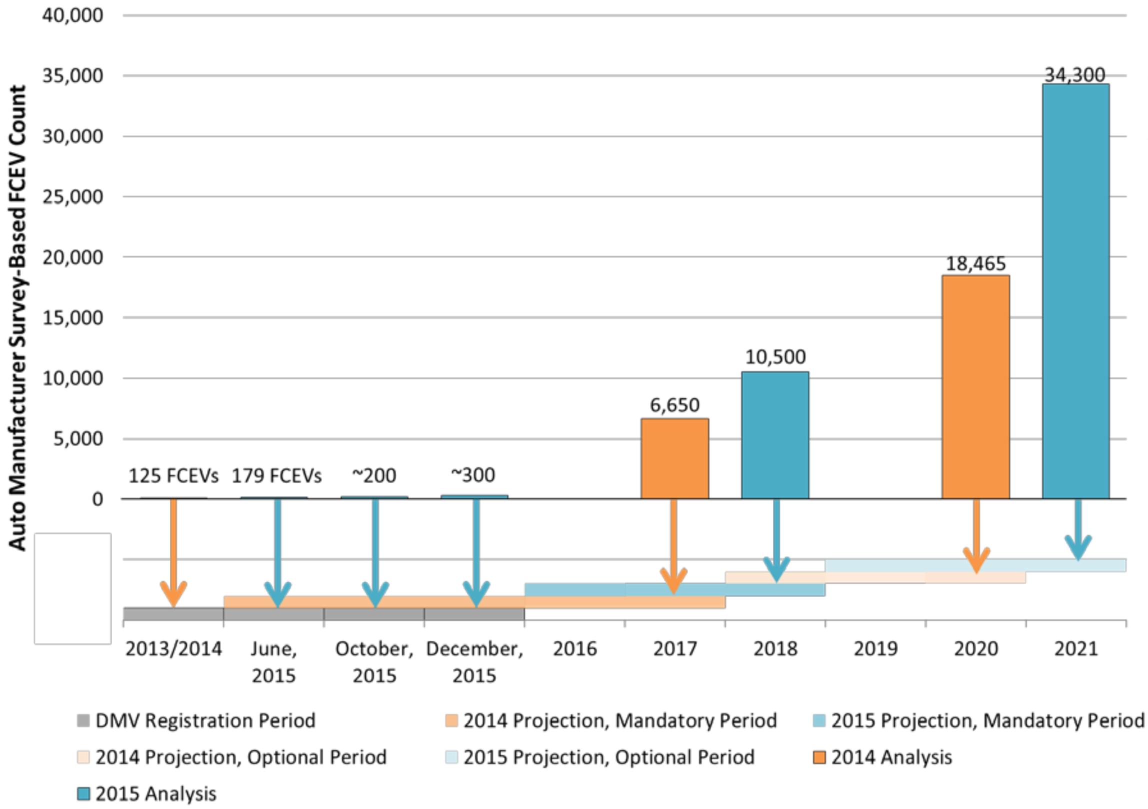
In its June report, ARB indicated that there were 179 FCEVs registered with the DMV in April 2015. Since then, ARB has received updated data from the DMV with registrations current as of early October 2015. Hyundai has been leasing Tucson Fuel Cells since 2014, and Toyota marked the official start of Mirai FCEV sales during an October 21, 2015 event.[7]

Accounting for the roughly 40 new Mirai owners (October 21), there were more than 200 FCEVs on the road in California by the end of October. Toyota also indicated its intention to sell or lease 100 total Mirai vehicles by the end of the year;[8] thus, nearly 300 total FCEVs are likely to be on California's roads by the end of 2015. Figure 3 summarizes the estimates of on-the-road FCEVs from ARB's 2014 and 2015 analyses and the new information available in October 2015. In the figure, the horizontal bars below the columns display the years for which ARB collected data in the 2014 and 2015 surveys. Each survey includes two periods. A mandatory period spans the three model years immediately following the survey date. An optional period spans the following three years, represented by a single sum for all projected deployments over the entire three-year period.

7 http://www.hybridcars.com/toyota-mirai-goes-on-sale-with-2000-preorders/.

8 Toyota is also announcing intentions to sell 30,000 FCEVs globally by 2020. http://www.reuters.com/article/us-toyota-environment-idUSKCN0S80B720151014.

Figure 3: Updated FCEV Population Counts and Projections (ARB)



Source: ARB

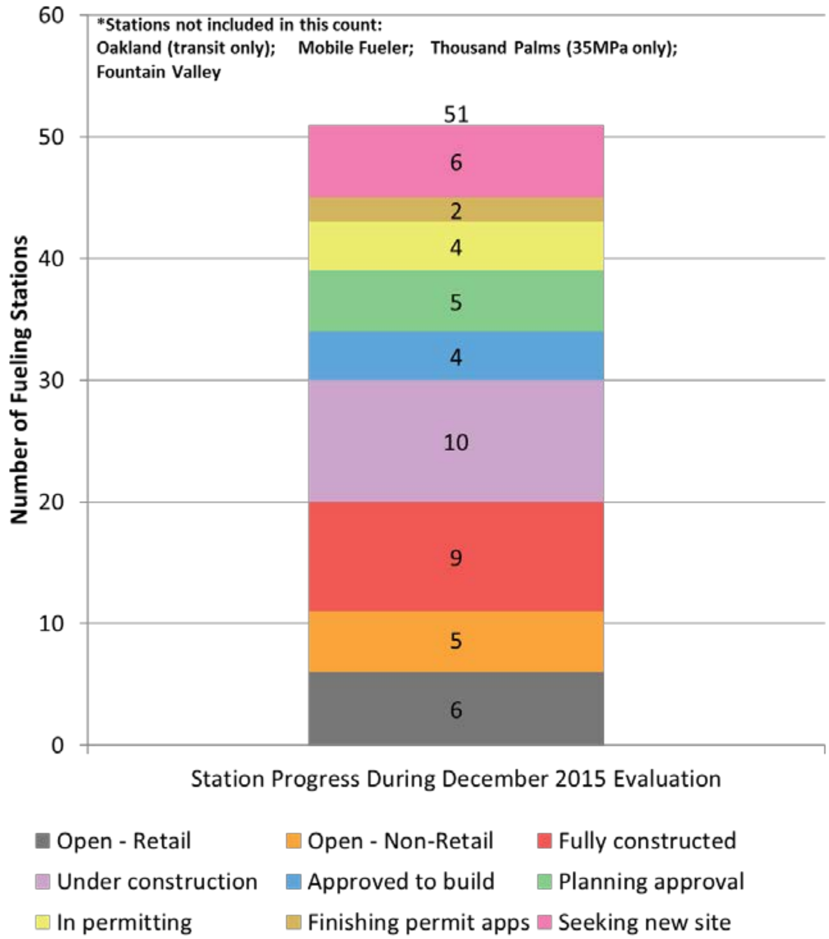
Status of Hydrogen Stations

Since the June 2015 Report, station developers have continued to make significant progress in advancing the development of the funded hydrogen fueling stations. In parallel, a broad set of industry stakeholders, including government agencies, auto manufacturers, station developers, and public-private partnerships, have been working to establish a well-defined consensus of the key milestones involved in developing a hydrogen fueling station. The Governor's Office of Business and Economic Development has played a leading role in bringing together this consensus and tracking station progress according to these milestones.

Figure 4 provides the status of all 53 existing and funded stations as of December 17, 2015. It is similar to a figure presented in the June AB 8 report, but the milestones have shifted according to the new definitions adopted by the stakeholders. A key distinction in the new definitions is the difference between "Open – Retail" and "Open - Non-Retail." As the vehicle market has recently shifted to full commercial production, the design and operation requirements for stations have also shifted away from technology demonstration to providing full retail fueling experiences for FCEV drivers. This includes point-of-sale capabilities that accept major credit cards as forms of payment, complete public access without the need for an access card or agreement, the ability for all users to fuel without the need of assistance from an attendant, and other considerations. Stations that meet these requirements are considered Open – Retail; the other technology demonstration stations that can provide fueling capability and may be endorsed for use by auto manufacturers, but do not meet all of the retail requirements, are considered Open – Non-Retail.

Since the ARB reported on station status in June 2015, much progress has been made, including 16 stations have completed the permitting process, stations under construction and in later phases have increased from 14 to 30, and the total number of stations in open phases has increased from 5 to 11. Furthermore, the two stations (Emeryville and Fountain Valley) were not counted in the June report due to uncertainty surrounding the likelihood of continued operation. Since June, substantial progress has been made to secure continued operation of the Fountain Valley site for at least one year, but the solution is not permanent; so it is still not included in the count of 51. However, the Emeryville station is now included in the count because it will likely become the site host for a station that requires a location change.

Figure 4: HRS Development Status for 51 Stations as of December 17, 2015

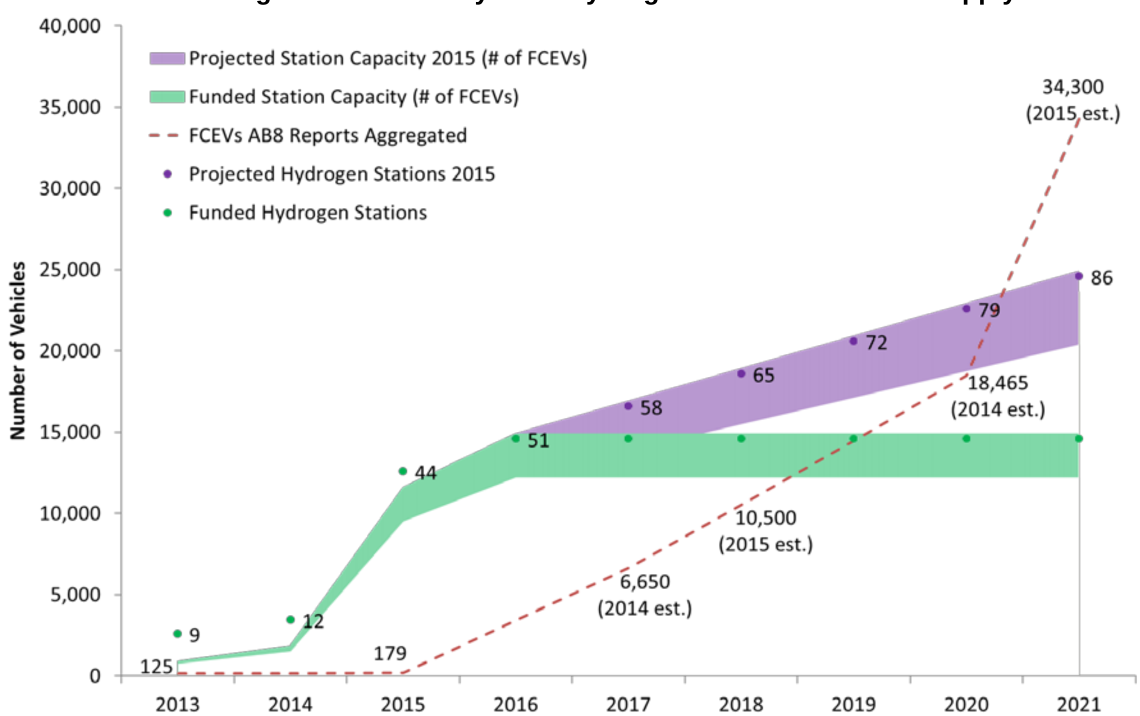


Sources: The Governor's Office of Business and Economic Development, California Air Resources Board, and California Energy Commission

Coverage and Capacity

In June 2015, ARB assessed the balance between the likely hydrogen demand according to vehicle deployment rates shown in Figure 3 and the likely growth in hydrogen fueling capacity from 2015 to 2021. To calculate the fueling capacity beyond the 51 stations currently funded and operational, ARB assumed 7 stations could be built each year with $20 million available through the ARFVTP. ARB based this on an Energy Commission projection of likely budgets available in future years, given an assumption of continuing to grant three-year operations and maintenance (O&M) grants in addition to grants to cover capital costs for new stations. In addition, the analysis assumed that the average station capacity would remain constant over that time and equal to the average of the 51 funded and operational stations, or 180 kg/day (with this capacity defined over the 12-hr peak fueling period). This initial block of 51 stations will offer sufficient capacity to fuel the 10,500 FCEVs anticipated in 2018. However, as shown in Figure 5, analysis of the balance between projected hydrogen demand and fueling capacity led to a major finding in the June 2015 report: By 2020, the accelerated hydrogen demand from FCEVs may outpace the rate of hydrogen fueling capacity provided by publicly funded stations. This finding is illustrated by the crossing of the red dashed line (which represents on-the-road vehicle counts) above the purple shaded area (the estimated range in number of vehicles that could be serviced by the indicated number of fueling stations) in the 2020-2021 time frame.

Figure 5: ARB Analysis of Hydrogen Fuel Demand and Supply



Source: ARB June 2015 AB 8 Report

Tools to Assess Hydrogen Station Locations

Before 2015, California agencies used the STREET model[9] to help determine the best locations for HRS in California. The STREET model integrated traffic flow information, demographic data, and air quality data to identify the key initial locations for the first clusters of HRS in California. In 2015, the state agencies shifted to a new set of assessment tools—California Hydrogen Infrastructure and Assessment Tools (CHIT and CHAT)—developed by ARB. These new tools provide higher levels of resolution in urban areas, allowing for more refined analyses in densely populated areas of Southern California and the San Francisco Bay Area where core market stations will be sited. CHIT also allows for state-level analysis and comparison of proposed HRS in different parts of the state.

ARB developed these tools to determine the location of the likely FCEV first adopter market, assess the coverage provided by the existing stations, and project future fueling capacity needs based on the data provided by the annual auto manufacturer surveys. The results of this analysis guide state investments toward stations that have the greatest potential for a positive business case because they are located in areas with the highest projected hydrogen demand.

CHIT is used to estimate the location and intensity of first adopter markets considering multiple demographic factors, including financial indicators, historical plug-in hybrid and hybrid vehicle registrations, and educational attainment. The magenta outlines in Figure 6 display the areas where the June 2015 assessment identifies the greatest potential for an FCEV first adopter market (not shown is an indication of the relative sizes of the markets). Other areas with high potential for a successful FCEV first adopter market exist; however, the regions highlighted in Figure 6 are among the highest-scoring regions in ARB's analysis and considered to be the focus of the early station network development.

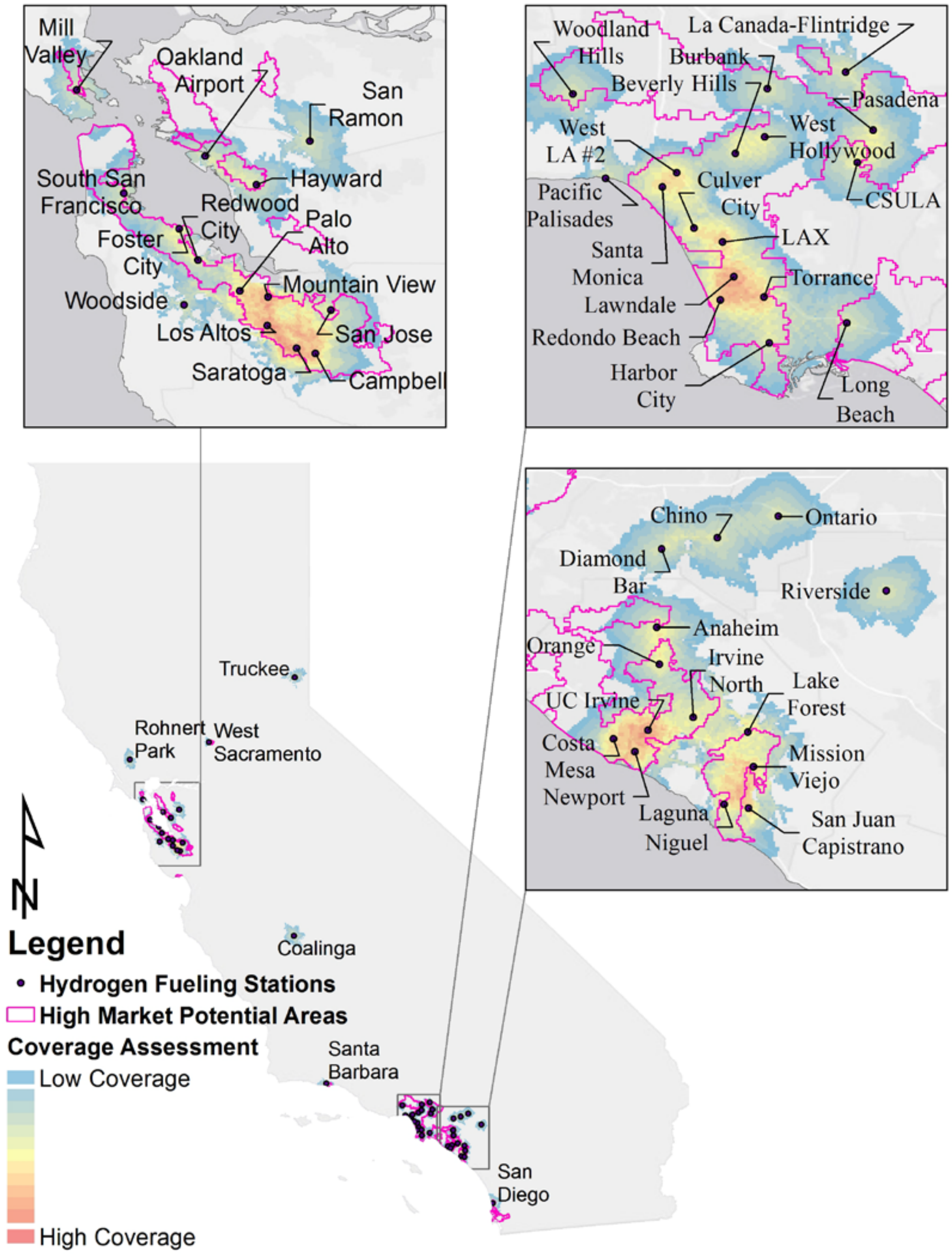
In addition to identifying the market, CHIT is able to assess the coverage provided by a set of fueling stations. CHIT performs this analysis by calculating service area coverage provided by each station within a set of multiple drive times. This provides an estimate of the farthest location from which a driver could reach a station within a given amount of time. These multiple service areas from multiple stations are then considered together in a scoring algorithm that accounts for overlapping coverage provided by various stations with varying degrees of convenience (indicated by drive time) to individual locations. The blue-to-red color shading in Figure 6 displays the coverage provided by the 51 stations evaluated in the June 2015 report. Coverage was calculated out to a maximum 15-minute drive time from each station; areas of the state with no coverage assessment shading are considered to have no coverage provided by any of the 51 stations.

9 STREET was developed by the University of California at Irvine and used by the Energy Commission for three solicitation cycles between 2009 and 2013.

These two major factors – the market and the current fueling station coverage – form the basis of the ultimate product of CHIT, the coverage gap evaluation. As Figure 6 shows, there are some areas of the state identified as part of the early adopter market that do not yet have a high degree of coverage or any coverage at all. (See San Francisco and the Berkeley area for examples.) This mismatch between coverage and market is the coverage gap, and CHIT provides a statewide assessment of the gap, accounting for the intensity of the localized variation in the first adopter market and the various degrees of coverage provided throughout the state. Patterns in the coverage gap are analyzed and then form the basis of ARB's suggested priority areas for future funding under AB 8.

Figure 6 also shows the many areas in California where the likely first adopter market needs are being addressed by the funded stations, such as near Silicon Valley. One major consideration for this analysis is that high coverage alone does not indicate sufficient infrastructure in a region; rather, CHIT measures the degree of coverage against the relative intensity of the market. Areas with high degrees of coverage may still be indicated as a priority for further funding if the local first adopter market is sufficiently strong. In addition, some stations have been built outside the likely first adopter market; some will serve as interregional connectors or destination stations, while others may have been built in areas that may become among the first markets to develop just after the high market potential areas indicated.

Figure 6: ARB CHIT Assessment of Areas of High Market Potential for FCEV Adoption



Source: ARB

CHAPTER 3: Hydrogen Station Development Timelines

Introduction

The Energy Commission's goal is to achieve a 24-month station development period that begins with announcement of a new funding opportunity and culminates with a completed station that is open for retail sale.[10] This period includes six months for the Energy Commission's work to issue a solicitation, review and rank proposals, announce funding awards, and approve the projects at a public Energy Commission business meeting. The next 18 months covers all station developer activities from acceptance of the grant award to opening the station for retail sales operations. Key milestones for this phase include: agreement execution, commercial lease agreement, planning outreach to local permitting agencies, planning approval, approval to build, construction, and commissioning.

Total permitting and station development timelines have varied widely over the three solicitations but, in general, are improving with a handful showing dramatic decreases in development time. The Energy Commission has worked to implement new standards and requirements in each successive solicitation in response to challenges and lessons learned from the preceding solicitation. Major new initiatives from GO-Biz and the California Fuel Cell Partnership (CaFCP) have also resulted in reduced permitting and station development timelines.

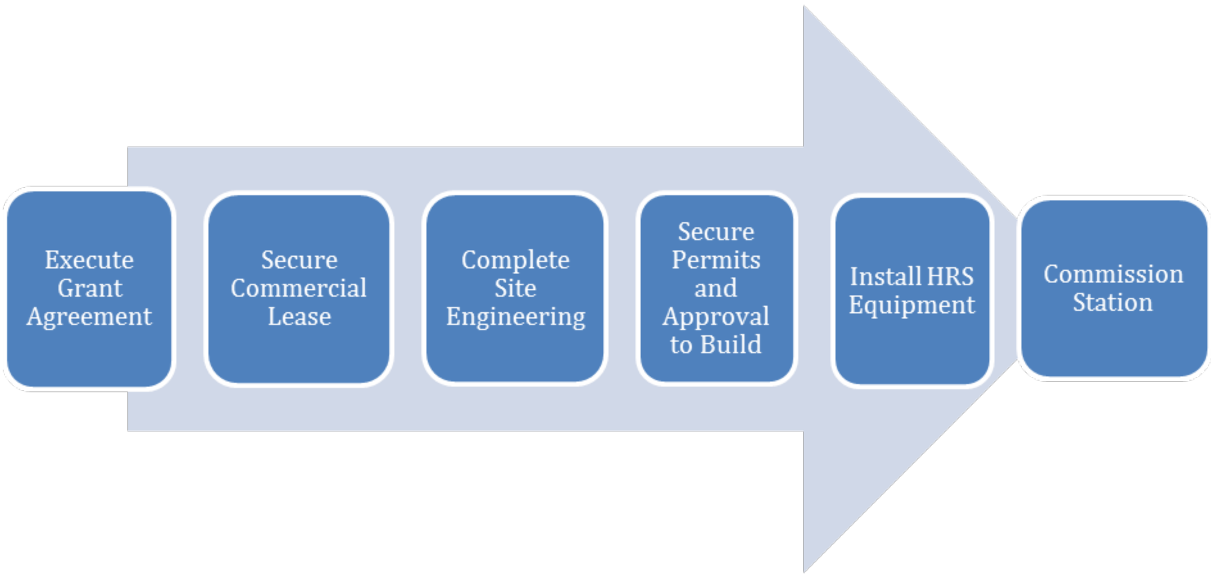
Hydrogen Station Development Timelines

This section identifies and analyzes HRS development timelines and trends for stations funded under PON-09-608, PON-12-606, and PON-13-607. Total station development time has improved substantially between the stations funded in 2009 and those funded in 2013.

The major phases for hydrogen refueling station development include, executing the Energy Commission grant agreement, securing a commercial lease, and completing site engineering and design plans. When the planning approval and approval to build are secured, the station developer must mobilize the construction team, install and construct the HRS equipment, and then confirm operations through the commissioning process. This sequence is illustrated in Figure 7. The Notice of Proposed Award, or NOPA, precedes the process.

10 Program Opportunity Notice 13-607 for Hydrogen Fueling Infrastructure, November 2013, California Energy Commission.

Figure 7: Sequence of Primary Phases in Hydrogen Station Development Process



Source: California Energy Commission

Each of the above phases is described as follows:

Grant Agreement Execution: This is a negotiated process between the HRS developer and Energy Commission staff. Key tasks are finalized and clarified, and the budget and final terms and conditions are agreed upon. This process culminates with Energy Commission approval of the grant at a public Business Meeting by a majority of Commissioners.

Secure Commercial Lease: This is a negotiated process between the HRS developer and the owner–operator of the retail gasoline fueling station. Terms of the commercial lease include monthly lease payments, liability, and duration of the lease agreement.

Complete Site Design and Engineering: A detailed site design and engineering plan must be developed by the station developer before the start of the permitting and approval process. The three primary equipment elements of the storage tanks, compressors, and dispensers must be placed within the generally small footprint of an existing retail gasoline station so as not to interfere with existing station operations.

Setbacks from existing structures in accordance with National Fire Protection Association (NFPA 2) must be identified during site design and engineering. NFPA 2 requires greater setback distances for liquid hydrogen than for gaseous hydrogen; therefore, hydrogen refueling stations using liquid hydrogen generally require a larger lot.[11]

11 National Fire Protection Association (NFPA). Quincy, Massachusetts. NFPA 2: Hydrogen Technologies Code: 2011, NFPA 2: 2011.

Secure Permits and Approval to Build: This process begins with initial outreach and consultation with the local planning commission and permitting authorities. Based on these discussions, the HRS developer submits a formal set of permit applications and design and engineering drawings for review and approval. The station application is reviewed by the planning department and may include one or more public hearings before the planning commission. Any needed mitigation or site upgrade features are determined during this phase. The fire marshal and other public safety authorities review the project, as do the building and code compliance departments.

Install HRS Equipment: This is the construction phase, in which all equipment is installed, connected, and powered. This typically involves excavation for underground equipment, pouring of concrete pads, equipment delivery, and installation. Utility service upgrades by the local utility are conducted, if needed.

Commission Station: During commissioning, the functionality and operations of all HRS systems are tested and confirmed. This begins with the confirmation of basic operations. The dispenser system must be certified as eligible for retail sale by the Division of Measurement Standards of the California Department of Food and Agriculture for accuracy of mass-based delivery. The local authorities having jurisdiction (AHJ) must confirm that the station has been constructed in accordance with the design plan and permit conditions. The station developer must demonstrate that the station conforms with the Society of Automotive Engineers' (SAE) technical fueling protocols (J2601). This can be done using FCEVs from multiple automakers, or with an independent testing device such as HyStEP.[12] The station developer must confirm that fuel quality standards are and will be met (J2719). Finally, the retail point of sale (POS) credit card terminal must be functional.

For terms of ARFVTP grants, the term "operational" is used to designate basic functionality and permit approval. This is distinct from the additional commissioning work needed to bring a station to full "open for retail sale" status.

Table 2 and Figure 8 show the average time needed for the major station development phases for the three main solicitations issued in 2009, 2012, and 2013. Table 2 shows average number of days needed per development phase in bold font. The italicized font indicates the number of stations per development phase upon which the average is based.

In developing the timelines, confirmed milestone dates were used. Staff calculated the average duration times for each development phase using the available data for stations that had completed that phase. For example, the permitting time for the 2013 stations is based on 18 of 28 stations while the construction time is based on 6 of 28 stations. The "Operational to Open for Retail" phase includes the average for the five stations open for retail sales.

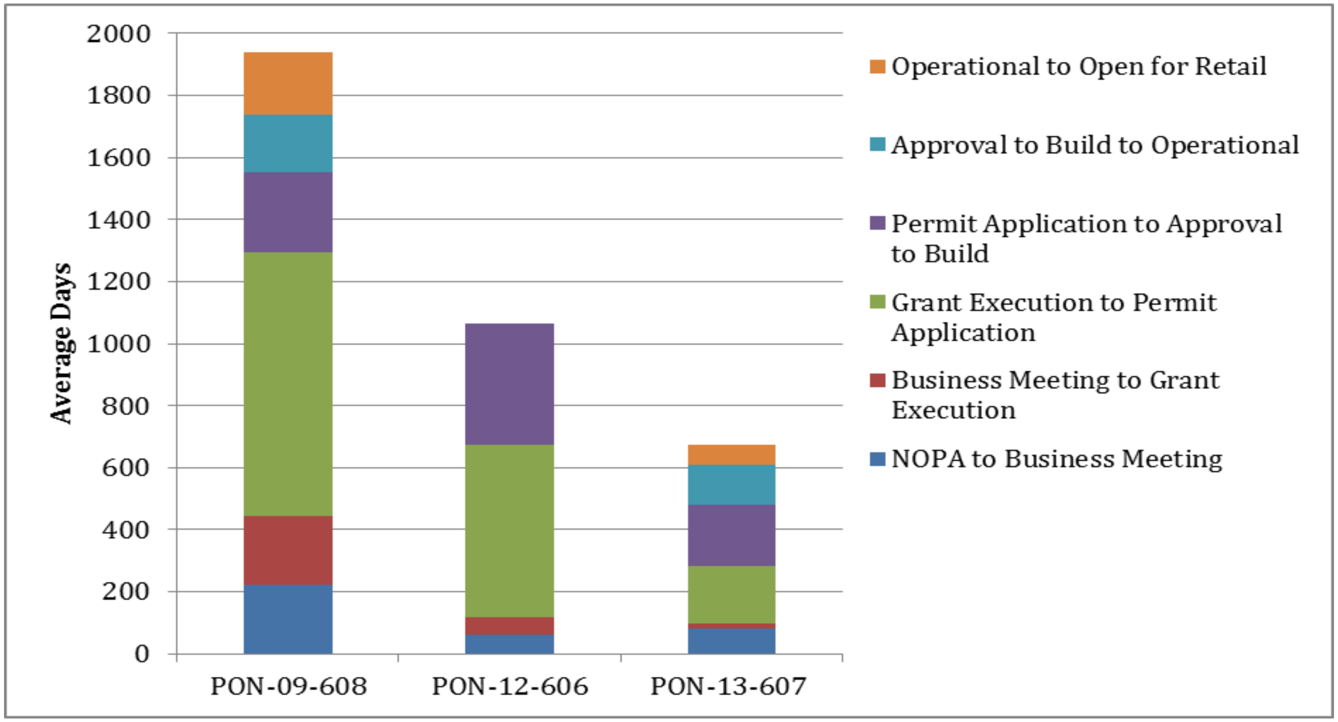
12 H2FIRST Hydrogen Station Evaluation Performance test device (HyStEP).

Table 2: Average Time for Each HRS Development Phase for Three Energy Commission Funding Solicitations

Energy Commission Grant Solicitation	NOPA to Business Meeting (days)	Business Meeting to Grant Execution (days)	Grant Execution to Permit Application (days)	Permit Application to Approval to Build (days)	Approval to Build to Operational (days)	Total Average Time become Operational (days)	No. of Stations with Site Change	Operational to Open for Retail (days)
PON-09-608	**224**	**219**	**853**	**255**	**186**	**1,737**	*7*	**202**
	10 of 10 stations	*10 of 10 stations*	*9 of 10 stations*	*7 of 10 stations*	*5 of 10 stations*			*4 of 10 stations*
PON-12-606	**62**	**56**	**556**	**391**	**N/A**	**TBD**	2	**NA**
	7 of 7 stations	*7 of 7 stations*	*6 of 7 stations*	*2 of 7 stations*	*0 of 7 stations*			*0 of 7 stations*
PON-13-607	**82**	**14**	**188**	**196**	**130**	**610**	6	**63**
	28 of 28 stations	*28 of 28 stations*	*23 of 28 stations*	*18 of 28 stations*	*6 of 28 stations*			*1 of 28 stations*
Total	**45**						**15**	

Source: California Energy Commission
Table Note: The three station upgrades funded by a California Energy Commission grant to the South Coast AQMD are not included.

Figure 8: Average Station Development Timelines per Solicitation (in days)



Source: California Energy Commission

Figure Note: Based on 5 of 10 stations for 2009, 0 of 7 stations for 2012, and 6 of 28 stations for 2013 have completed construction. See Table 2.

Factors in Station Development Times

As shown, total average station development time has improved significantly between 2009 and 2014, decreasing from 4.9 years for five stations funded in 2009 to just over 1.6 years for six stations funded in 2014, the highest-performing station development projects in PON-13-607. Increased learning and knowledge by station developers and Energy Commission staff have resulted in multiple changes in the funding solicitations and grant agreements issued by the Energy Commission, and in improved practices by the station developers.

Several broad factors have contributed to this improved efficiency in HRS station development. The first major factor involves the timing of HRS development in relation to commercial release of FCEVs. As described by the auto industry, there is a multi-year lead time for developing production schedules and modifying assembly lines for FCEVs. Without confidence that a minimum number of hydrogen stations would be available for its initial customers, the auto industry has been conservative in developing and announcing new FCEV product lines.

To minimize financial loss from a network of 50 to 60 operational stations with few FCEV customers, station developers and operators have also been conservative.

The ongoing commercial developments within the auto industry and station development industry are helping increase certainty that the initial investments can be recouped. Three major automakers began announcing plans for commercial launch of FCEVs (Hyundai, Toyota and Honda); Hyundai began commercial launch in June 2014, while Toyota began its launch in October 2015. Honda plans a commercial launch in 2016. This, in turn, strengthened the certainty for retail sale of hydrogen fuel by the station developers and operators, which is resulting in much shorter station development timelines for the most recently awarded stations.

A second major factor has been the State of California's actions to create more confidence and policy certainty for hydrogen station development. The recent funding commitment contained within AB 8 to designate up to $20 million a year to develop 100 stations by 2020 seems to have created the certainty needed by station developers and automakers to commit to building stations in earnest. Before the AB 8 designation of $20 million (or 20 percent) of ARFVTP funding for HRS, Energy Commission funding for HRS varied year to year.

Finally, perhaps the most effective Energy Commission response to alleviating station development challenges and delays has been the creation of sliding-scale incentives that are linked to HRS operational dates. In the 2013 solicitation, station developers were offered capital project support of up to 85 percent or $2.125 million if stations could become operational by October 31, 2015. Stations becoming operational between November 1, 2015 and February 29, 2016 are eligible for 75 percent or $1.875 million (whichever is less). Stations becoming operational after February 29, 2016 are eligible for 70 percent or $1.75 million (whichever is less). A similar incentive structure was created for Operations and Maintenance funding grants as well.

Only 5 of the 29 stations funded in the 2013 solicitation were able earn the maximum “fast track” incentive. The fastest station development time to date has been 548 days (1.5 years) for the FirstElement station in Coalinga along Interstate 5.

Following are additional challenges and factors that have led to delays in developing hydrogen stations, along with the Energy Commission’s response actions to alleviate the challenges:

Grant Execution: The two grantees in 2009 averaged more than 200 days to review and execute the Energy Commission grant agreement documents. This is a long time compared to grantees who have won ARFVTP awards in other alternative fuel categories.

In 2012, the Energy Commission added a provision to the solicitation and grant agreement contracts requiring agreement execution within 90 days, after which the Energy Commission would evaluate whether to cancel the award and allocate the project funding to the next eligible applicant.

The average time needed for grant execution dropped to 56 days for the 2012 awardees and then to 14 days for the 2013 awardees.

Commercial Lease Factors: Finalizing the commercial lease agreement with the station operator and owner has been an ongoing challenge for HRS developers. Gas station owners have expressed uncertainty about using valuable urban real estate for an uncertain fueling technology or have been unwilling to commit to a HRS developer before the finalization of an ARFVTP grant. Given that 30 percent (15 of 49) projects have required a site change, the Energy Commission has worked to require increasing levels of certainty that a commercial lease agreement will be finalized for the site proposed to the Energy Commission.

In the 2013 solicitation, the Energy Commission added a requirement that the station owner/operator must sign a letter of support that indicates his or her commitment to hosting the hydrogen station should the developer win a grant award. With the 2014 awardees, 20 percent of the projects (6 of 29) were still unable to finalize a commercial lease agreement. While better than the 70 percent loss rate from 2010, this continues to be one of the most challenging issues for hydrogen station development in California.

Project Readiness: The concept of “project readiness” is to require and provide incentives for project developers to proactively complete as much work as possible before submitting a grant application so that work can be completed as quickly as possible after the grant award is issued. This proactive work can include pre-application meetings with local planning and permitting authorities, advance outreach to public safety officials and the community, advance negotiations on the commercial lease, completing as much engineering and site design work as financially feasible, ensuring that major equipment suppliers are alerted and prepared for new orders, and ensuring that major subcontractors are prepared to sign subcontracts with the prime awardee and schedule work in advance. These project readiness factors have been incorporated into the scoring criteria in the past two solicitations.

State Permitting Assistance: In response to automaker concerns about the slow pace of station development, the State of California created a new position in 2014 within the Governor’s

Office of Business Development (GO-Biz) to assist on general HRS development issues and specific local government planning issues. The ZEV Infrastructure Manager has been very active in accompanying project developers to meetings with local planning officials and permitting officers, and at public hearings and workshops. Senior Energy Commission staff has also been active in these meetings.

In collaboration with the California Fuel Cell Partnership and the auto industry, State agencies have helped conduct three general planning and awareness building workshops focused on local government planners, public safety officials, city council members and staff, and the public. Automakers bring FCEVs and make them available for ride and drives. These regional workshops were held in Torrance, San Diego and Palo Alto. Additional workshops will be conducted as needed in areas that do not yet have many HRS or FCEVs.[13]

HRS developers are also learning how to approach and engage AHJs more effectively than in earlier years, such as taking advantage of opportunities for pre-application meetings so that AHJs can develop early familiarity with the issues involved with HRS development. FirstElement has also hired a former city planner on its station development team. FirstElement has obtained 13 Approvals to Build for the 19 HRS awards it received in 2014.

Average permitting times for the 2013 stations are now two months faster than for the 2009 stations, averaging 196 and 255 days, respectively. The shortest time to date has been 61 days.

Incentive Funding: Perhaps the most effective Energy Commission response to alleviating station development challenges and delays has been the creation of sliding scale incentives that are linked to HRS operational dates. In the 2013 solicitation, station developers were offered guaranteed capital project support of 70 percent of total project costs or $1.75 million, whichever is less. Stations becoming operational on or before February 29, 2016 are eligible for increased funding support of 75 percent or $1.875 million, whichever is less. Full incentives could be earned if stations became operational on or before October 31, 2015. Stations earning the full incentive are eligible for 85 percent or $2.125 million, whichever is less. A similar incentive structure was created for Operations and Maintenance funding grants as well.

Five of the 29 stations funded under the 2013 solicitation were operational by October 31, 2015 and therefore earned the full funding incentives available. The fastest station development time to date has been 548 days (1.5 years) for the FirstElement station in Coalinga along Interstate 5.

Hydrogen Station Commissioning: Once the local AHJ has confirmed a station has been constructed in accordance with the design plan and permit conditions, the commissioning process fully engages. Commissioning includes certifying the dispenser for retail sale, confirming that the dispensed hydrogen fuel meets the SAE J 2719 quality standards, confirming that the station dispenses according to the SAE J 2601 fueling protocol, and

13 Additional city-level workshops were held in Huntington Beach, Culver City, Oakland, and Hayward.

confirming that the retail point of sale terminal is functional. Much progress has been made in the last few years to improve each step in hydrogen station commissioning. Stations being deployed feature familiar appearing dispensers, accept credit card payment, and dispense certified and metered hydrogen charged by the kilogram – the international unit for hydrogen sales. Through station commissioning, the station operator and automakers build confidence these features meet performance criteria necessary for a positive customer experience. While much progress has been made to coordinate and shorten commissioning time, more work remains to achieve a streamlined and routine commissioning process. The report discusses gains in efficiency for two of the steps.

Station Fueling Protocol: Before a station is approved for customer use, each automaker currently performs a series of fueling validation tests using its own test vehicles and engineers, with the station builder providing technical support personnel. The process requires multiple tests and has taken up to six months or more to complete for some stations. A new device developed by the U.S. Department of Energy (DOE), Sandia and NREL will streamline and shorten this process to ensure a safe, fast and complete fill for customers. The State of California is a key stakeholder and partner in the development of the Hydrogen Station Evaluation Performance test device (HyStEP) with the objective to accelerate station commissioning by testing dispensers for compliance with the SAE J 2601 fueling standard. ARB will facilitate field pre-deployment validation testing together with automobile and station builders in late 2015 and begin evaluating stations in early 2016. Once sufficient station evaluations have been completed, the State will work with stakeholders to develop a station validation protocol or regulation. In time the HyStEP device can serve as a vehicle surrogate and is expected to be used in place of the majority of automaker testing, and can help chart a path to certification or listing by Nationally Recognized Testing Laboratories, further accelerating the station commercialization process.

Hydrogen Metering: The Division of Measurement Standards, a part of the California Department of Food and Agriculture, is the only entity in the State qualified and capable of certifying hydrogen dispensing equipment for the unit sale of hydrogen. Dispensing equipment that has not previously been evaluated for accuracy requires a full evaluation under the California Type Evaluation Program led by DMS. Once dispensing equipment is type certified, identical equipment can be deployed at new locations, and a less extensive evaluation is performed to allow the unit sale of hydrogen. This confirmation testing of type certified equipment can be performed by a Registered Service Agent (RSA). Two dispenser equipment providers now have type certified hydrogen dispensing equipment and, one entity has applied to be an RSA. The RSA will be able to certify a type certified station, allowing limited DMS staff to focus on type certification and HyStEP implementation.

Incentive Funding

The Energy Commission has issued three solicitations for hydrogen fueling station development since 2009. The offers for capital support have ranged from 60 percent to 85 percent of total HRS equipment and installation costs (all-in costs). In contrast, the standard offer with other ARFVTP-supported infrastructure such as EV charging stations, E-85 ethanol stations or CNG fueling stations has been 50 percent capital match. More recently the Energy Commission has been offering from 75 to 100 percent capital match for development of EV fast charging stations along freeway corridors in remote parts of California.

A key challenge for the Energy Commission is determining the appropriate capital offer to HRS developers so that HRS development is financially stimulated and accelerated without overpaying station development companies. Table 3 shows the funding levels, capital offer percentages, and number of funded stations for the three solicitations offered by the Energy Commission thus far.

Table 3: Summary of Funding Levels and Capital Match Offers for Three Energy Commission Hydrogen Solicitations

Solicitation No.	CEC Capital Grant Share	Total Funding Available ($ million)	Incentive Funding	Results
PON-09-608	40% to 70%	19	Accelerated Completion	11 stations funded
PON-12-606	65% or $1.5 M	28.6	No	Undersubscribed by $6.7 M 5 stations funded
PON-13-607	70% to 85% or $1.75 to $2.1 M	46.6	For Speed of Development	Oversubscribed 28 stations funded

Source: California Energy Commission

The 2009 solicitation used a sliding incentive scale focused on accelerated completion from date of permitting to operational. In total, 11 stations were funded. Final Energy Commission awards ranged from 60 to 75 percent of capital costs. Although development proceeded slowly, Energy Commission staff assumed that the stations would be constructed on time and budget because awarded companies are contractually obligated to deliver retail stations when they accept public grant funding awards. In 2012, the Energy Commission solicitation offered a lower capital offer of 65 percent, based on the assumption that total installed costs for HRS were beginning to decline.[14] The predominant view in National Laboratory and academic studies is that total HRS costs should range from $1 million to $1.8 million. Industry response to the 2012 solicitation was low, and only five stations were funded.

For the 2013 solicitation, which had $46.6 million available from multiple fiscal years, Energy Commission staff sought to buy down more of the investment risks by offering up to 85

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14 The 2012 FCP California Roadmap estimated all-in station development costs to range from $0.9 million for 170 kg/day coverage stations to $2 million for 400-500 kg/day core market stations (Table 7).

percent or $2.125 million per station. An incentive structure was also developed that provided the full 85 percent for stations achieving the October 31, 2015 milestone goal, established to coincide with automaker announcements for FCEV market launch. An Operations and Maintenance (O&M) grant program was also initiated that would provide up to $100,000 per year over three years in documented O&M costs to offset very low sales revenues in the early market years of commercial FCEV launch. This solicitation was oversubscribed and funded 28 HRS plus the mobile refueler. One additional station passed but was not awarded funding due to lack of funds while an additional 31 stations were disqualified in accordance with solicitation requirements.

CHAPTER 4: Hydrogen Station Equipment and Development Costs in California

Introduction and Background

While hydrogen is ubiquitous in the world's economy as an industrial gas used in the refining, fertilizer, electronics and food processing industries, it is generally used at lower pressures than required by the auto industry. The auto industry standard for passenger vehicles is for 700 bar fueling pressures (70 megapascals or MPa), or 10,000 pounds per square inch. Standard delivery pressures are much lower. The combination of high pressures and very small station footprints mean that initial equipment costs are higher per station when compared to other alternative fueling infrastructures like electric chargers or E-85 ethanol or biodiesel fueling stations. Only high-volume compressed and liquefied natural gas stations, which require similar storage and compression technologies to HRS, approach the per-station costs for HRS. Station costs for greenfield compressed natural gas stations can exceed $1 million, while costs for a new liquefied natural gas station can exceed $2 million.[15]

Over the long term, as FCEV sales and consumer acceptance grow, the initially high early market costs of HRS are expected to drop and with growing hydrogen demand will enable a positive business case for retailers and hydrogen price parity with gasoline. This long-term market viability has been examined in numerous studies.[16]

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15 Based on project cost data from ARFVTP project files for CNG and LNG fueling stations.

16 Ogden, Joan M. 1999. "Prospects for Building a Hydrogen Energy Infrastructure." *Annual Review of Energy and the Environment* 24: 227–79.

Greene, D. L., P. N. Leiby, B. D. James, J. Perez, M. Melendez, A. Milbrandt, S. Unnasch, and M. Hooks. 2008. *Analysis of the Transition to Hydrogen Fuel Cell Vehicles & the Potential Hydrogen Energy Infrastructure Requirements.* Report number ORNL/TM-2008/30. Oak Ridge National Laboratory.

McKinsey. 2010. *A Portfolio of Power-Trains for Europe: a Fact-Based Analysis*. McKinsey & Company.

Melaina, M W, G Heath, D Sandor, D Steward, L Vimmerstedt, E Warner, and K W Webster. 2013. *Transportation Energy Futures Series: Alternative Fuel Infrastructure Expansion: Costs, Resources, Production Capacity, and Retail Availability for Low-Carbon Scenarios*. National Renewable Energy Laboratory (NREL), Golden, CO.

National Research Council. 2013. *Transitions to Alternative Vehicles and Fuels*. Committee on Transitions to Alternative Vehicles and Fuels; Board on Energy and Environmental Systems; Division on Engineering and Physical Sciences; National Research Council. www.nap.edu/catalog/18264/transitions-to-alternative-vehicles-and-fuels

The current generation of modern technology hydrogen fueling stations co-funded by the Energy Commission ranges from $2.1 million to more than $3 million per station. Average station capacity ranges from 100 kilograms (kg) per day to 350 kg/day. Table 4 shows total station costs, technology and capacity for the 49 stations funded to date through the Energy Commission. Nearly all of these stations are being installed in existing retail gasoline stations in urban or suburban regions.

Because relatively few stations are constructed and operational, the station costs category reflects the total costs as bid into the most recent Energy Commission funding solicitation by each developer and does not reflect any potential cost changes during construction. These costs include equipment procurement, installation, project management, and administrative overhead. Levelized costs assume full utilization (about 75 percent of station capacity), nominal values for hydrogen delivery and operation and maintenance costs, and standard finance assumptions. Actual costs per kg at each station will vary significantly based upon individual locations, real-world utilization rates, specific financial arrangements, and other factors. Operating costs and other factors contributing to levelized costs are discussed later in the report.

Numerous DOE National Laboratory reports and academic studies investigate current costs and predict future costs of hydrogen fueling stations in the U.S. Most such reports project that station costs will decrease as more vehicles enter the market and station-level hydrogen fuel sales increase. However, most of these reports tend to underestimate current early-market station costs. For example, a recent Sandia–NREL report conducted for DOE's H2FIRST program estimates equipment and installation costs for a 200 kg/day gaseous station with tube trailer gas delivery at $1.18 million, while a 300 kg/day liquid station is estimated to be $2.01 million.[17]

While the cost estimates from National Laboratory and academic analyses are highly informative, the costs described in Table 4 reflect early market, real-world conditions for the largest network of hydrogen fueling stations to date in North America. In contrast, academic and National Laboratory cost estimates are based on industry-vetted models but are more theoretical by comparison due to the lack of data from constructed and operational HRS. The goal of this first AB 8 Cost Report is to document actual equipment, installation, and operating costs for urban and suburban California regions. These baseline costs then serve as the basis for estimating future costs associated with an expanded HRS network out to 2025.

17 H2FIRST Reference Station Design Task, Project Deliverable 2-2, Sandia, Argonne and National Renewable Energy Laboratories, April 2015.

Table 4: Summary of 49 Hydrogen Fueling Stations and Technologies Funded with Energy Commission ARFVTP Funding

Station Developer	No. of Stations Funded	Station Technology	Technology Provider	Average Daily Capacity (kg/day)	Total Station Cost ($ million)	Levelized Costs ($/kg)
FirstElement	19	Delivered Gaseous H2	Air Products and Chemicals	180	2.05	$13.00
Air Products and Chemicals	10	Delivered Gaseous H2	Air Products and Chemicals	180	1.93	$12.40
Linde	7	Delivered Liquid H2	Linde	350	2.78	$9.90
HyGen	3	On-Site Electrolysis	Giner	130	3.25	$24.00
Air Liquide	2	Delivered Gaseous H2	Air Liquide	180	3.26	$13.80
ITM Power	1	On-Site Electrolysis and Delivered H2	ITM Power	100	2.73	$22.70
H2 Frontier	1	On-Site Electrolysis	ITM Power	100	4.61[2]	$33.30
HTEC	1	On-Site Electrolysis and Delivered H2	McPhy	140	3.25	$17.90
Ontario CNG	1	On-Site Electrolysis	Hydrogenics	100	2.51	$18.30
Upgrade Stations						
H2 Frontier (Burbank)	1	On-Site SMR[1]	H2GEN	100	0.93 [4]	NA[3]
Air Liquide (L.A. – Aviation Blvd)	1	On-Site SMR and Delivered H2	Air Liquide	180	2.12 [4]	NA
TBD	1					NA
Shell Equilon (Torrance)	1	Pipeline Delivery	Air Products and Chemicals	200	2.47[4]	NA
Totals	**49**			**9,260**		

Source: California Energy Commission

1 Steam Methane Reforming
2 This award from the 2012 PON and NOPA was one of the first 100 percent renewable hydrogen awards using the "set-aside" funding of up to $3 million for renewable hydrogen stations.
3 The upgraded stations are managed under a separate agreement with the South Coast Air Quality Management District and detailed station cost information is not yet available.
4 These numbers represent awarded amounts

Hydrogen Station Costs for Three Predominant Equipment Systems

Hydrogen station equipment systems being used in California can be grouped into three main categories: delivered gaseous hydrogen, delivered liquid hydrogen, and on-site generation and retail sale of hydrogen using electrolysis.[18] Of the 49 HRS funded through the Energy Commission, 31 use the delivered gaseous system, 7 use the delivered liquid system, and 8 use on-site electrolysis. Two earlier technology demonstration projects being upgraded in Southern California use on-site steam reformation, while a third upgrade project will use pipeline delivery. This section examines current station equipment costs for each of these three systems. It also examines current operational costs, including compression and delivery charges. At present, the vast majority of California's hydrogen fuel will be produced with industrial scale steam reformation facilities co-located with petroleum refineries.

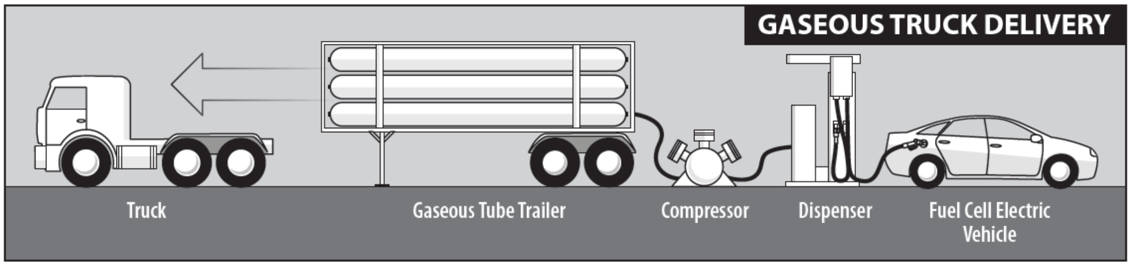
Delivered Gaseous Hydrogen Systems

The predominant HRS system in use in California is the 180 kg/day delivered gaseous hydrogen station (delivered over a 12-hour period), which is considered an early market coverage-level HRS. This system includes production of gaseous hydrogen from a central station steam reformation production facility (typically associated with petroleum refinery operations and producing hydrogen from a mixture of fossil natural gas and renewable landfill gas), transport to the retail station through a high-pressure tube trailer, and then pressurized delivery to ground vessel storage or swap out of the tube trailer. The retail station equipment includes low-pressure hydrogen storage vessels, a compressor to boost pressure to 900 bar, high-pressure storage, a cooling block chilling system, and a dual-pressure dispenser capable of dispensing at 350 and 700 bar (35 MPa and 70 MPa or 5,000 and 10,000 psi).

Figure 9 is a schematic representation of the major equipment and flow diagram for a typical 180 kg/day delivered gaseous HRS. Figure 10 shows photographs of recently completed and operational 180 kg/day stations by APCI and FirstElement.

18 Two other HRS technologies have been demonstrated in California. One is the Shell–Torrance pipeline station, which tapped a local hydrogen pipeline serving petroleum refineries. The other is an on-site steam reformation system also demonstrated by Shell in Newport Beach, which is being decommissioned.

Figure 9: Schematic Diagram of a 180 kg/day Delivered Gaseous HRS



Source: NREL

Figure 10: Photographs of New 180 kg/day Hydrogen Refueling Stations

APCI Dispenser at AQMD Diamond Bar Offices

(Courtesy South Coast AQMD Staff)

First Element Dispensers in Long Beach (above) and Coalinga (below) (Courtesy FirstElement, Inc.)

Assuming operations at full nameplate capacity of 180 kg/day, and assuming 0.7 kg of fuel per vehicle per day, a coverage-level station at this size could service about 250 vehicles at full capacity. However, standard operating capacity is assumed to be about 75 percent, which would service about 175 vehicles. This estimate represents the average size of the vehicle fleet that could be serviced by any 180 kg/day station as part of the full hydrogen fueling network. On any given day however, a 180 kg/day station could serve about 45 vehicles during the peak fueling period, given an average 4 kg fill. Off-peak fueling, with sufficient scheduled delivery and/or production of hydrogen, could allow the station to serve a few additional vehicles over a 24-hour period.

More than 30 stations use this equipment system, including the 19 stations developed by FirstElement, the 10 stations developed by Air Products and Chemicals, and the 3 stations developed by Air Liquide. APCI develops its own equipment package, which is also used by First Element. Air Liquide has its own equipment system.

Table 5 shows the equipment list and costs – when available – for the major equipment elements of a delivered gaseous system. This particular cost estimate is based on the proposal data received in response to PON 13-607, combined with follow-up interviews. Some cost information not included in the proposal was extrapolated from equipment information from other suppliers and proposals. It is intended to be representative of the current major equipment costs associated with a delivered gaseous HRS.

Table 5: Equipment List and Estimated Cost for a Typical 180 kg/day Delivered Gaseous HRS

FirstElement Fuel Hydrogen Refueling Station		
Equipment List	**Delivered Cost ($)**	**Notes and Specifications**
Ground Storage	$ 370,000	250 kg Type 3 - 25 tubes
Compressor	$ 270,000	40 HP reciprocating compressor
Dispenser	$ 270,000	Dual-hose, 350 and 700 Bar
High Pressure Tubes	$ 135,000	Fiba Type 2 storage tubes - 3 @ $45,000 each
Chiller	$ 150,000	Aluminum block with internal coil tubing
Tubing and Valves	$ 150,000	Specialty tubing and valves for high pressure hydrogen systems
Misc. Material and Equipment	$ 230,000	Electrical- and construction-related materials
Point-of-Sale System	$ 20,000	
Utility Connection Equipment	$ 12,000	
Total Equipment and Material	**$ 1,607,000**	

Source: California Energy Commission, based on submitted bid information combined with follow-up interviews.

Table 6 integrates the equipment costs with engineering, permitting, construction, and general management and overhead costs.

Table 6: Engineering, Permitting, Construction and General Overhead Costs for a Typical 180 kg/day Delivered Gaseous HRS

FirstElement Fuel - Hydrogen Refueling Station		
Activity	**Cost ($)**	
Site Engineering and Design	$	23,300
Permitting	$	14,300
Construction	$	280,000
Commissioning	$	35,700
Project Management and General Ov	$	54,500
Activity Subtotal	$	407,800
Total Equipment (Table 5)	$	1,607,000
Total Installed Cost (All-In)	**$**	**2,014,800**

Source: California Energy Commission, based on submitted bid information combined with follow-up interviews.

Permitting, site engineering, construction, commissioning, and general overhead average about $407,000 per station, according to bid information and follow up interviews. Again, these cost estimates are intended to be representative of early market, low-capacity station development, rather than predictive of future costs. The final "as-built" costs may vary from these bid estimates.

Total all-in costs for a 180 kg/day delivered gaseous hydrogen refueling stations are estimated to be just over $2 million at present.

Operations and Maintenance Costs

Hydrogen station operators must pay ongoing costs related to the operations and maintenance of the HRS. The primary operational costs include the delivered hydrogen, electrical power to run the compressors, chillers and dispenser, lease or rent, labor, and insurance. Primary maintenance costs include labor for inspection, preventive maintenance, and troubleshooting, and then for replacement of equipment subject to normal use and wear, or equipment that has failed prematurely.

Cost information for operations and maintenance activities is sparse given how few HRS in California have been open for retail sales. The Energy Commission's Operation and Maintenance grant program will become a source for complete O&M cost information in subsequent reports. At the time of this writing only a few HRS have been operational long enough to apply for O&M grant funding.

However, three informative data cost points are available:

Delivered Cost of Hydrogen: Based on O&M invoices from a demonstration-era station in Southern California, pressurized gaseous hydrogen is being delivered for about $8 per kilogram.

Lease Payments: One company has submitted an O&M invoice with lease payment information from a nonurban station site. While informative, the $2,600 monthly payment may not reflect urban, core market real estate values.

Maintenance Costs: Based on only one company's submitted invoicing, monthly maintenance costs seem to range from $800 to $1,500 per month.

Delivered Liquid Hydrogen Systems

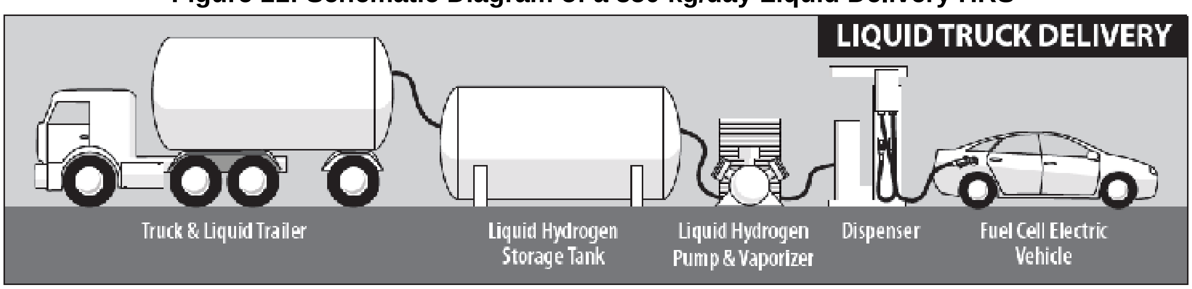
Another predominant technology for delivered hydrogen in California is the 350 kg/day liquid hydrogen system. Seven of these are in development in Northern and Southern California. The Linde Group has pioneered development of this technology in Europe and North America. The key difference with liquid delivery systems is that the hydrogen gas is chilled until it converts to a liquid phase, which allows it to be transported at greater density and lower pressures than gaseous hydrogen.

Liquefied hydrogen is produced from natural gas at central steam reformation plants in the same manner as gaseous hydrogen. Additional process energy is used as the hydrogen gas is converted to a liquid state, which means that liquid hydrogen has a higher carbon intensity value than gaseous hydrogen for the production stages. Some of this is offset by the reduced frequency of truck deliveries allowed by the higher density of the hydrogen. The liquid hydrogen is pumped into pressurized and temperature-controlled transport trailers and delivered to the retail station.

At the station, the liquid hydrogen is stored in large temperature-controlled, above-ground tanks. The liquid hydrogen expands to a gaseous state as it is transferred to the pre-dispenser tank. The hydrogen is then boosted to the required pressure levels for either 700 bar or 350 bar fueling.

Figure 11 is a schematic representation of the major equipment and flow diagram for a typical 350 kg/day delivered liquid HRS.

Figure 11: Schematic Diagram of a 350 kg/day Liquid Delivery HRS



Source: NREL

Equipment and installation costs for a liquid hydrogen station tend to be higher than for a delivered gaseous station. Additional tankage and chilling equipment add to the higher equipment costs and construction costs. The liquid hydrogen fueling equipment also requires more land area within a gasoline retail station and greater setback distances from buildings and other equipment.

Figure 12: Linde Group's West Sacramento Liquid Delivery HRS

Linde Group's 350 kg/day station in West Sacramento
Energy Commission Staff Photo

Table 7 shows the equipment list and costs for the major equipment elements of a delivered liquid system. This particular cost estimate is based on the proposal data received from Linde Group for the San Ramon station in response to PON 13-607, combined with follow-up interviews. It is intended to represent the current major equipment costs associated with a delivered liquid HRS. Because the San Ramon site is a greenfield site, total installed costs are somewhat higher than for Linde's bids in 2009 and 2012 for HRS in existing gasoline stations.[19]

19 These costs reflect Linde Group's internalized cost structure for development of a liquid delivery HRS and do not reflect any mark-ups that Linde would add to equipment packages sold to third-party HRS developers.

Table 7: Equipment List and Estimated Costs for a 350 kg/day Liquid Delivery HRS on a Greenfield Site

Linde - Hydrogen Refueling Station - San Ramon		
Equipment List	**Delivered Cost ($)**	**Notes and Specifications**
Liquid Storage	$ 92,000	Refurbishment of 1 vessel, 3000 gallons
High Pressure Tubes	$ 113,000	
Compressors	$ 778,000	Linde IC90, ionic compression unit and cold fill
	$ 12,000	Compressor to supply instrument air
Dispenser	$ 294,000	350/700 Bar Dispenser & Chiller
Point of Sale System	$ 25,000	
Connection to Utilities	$ 42,000	
Misc. Material and Equipment	$ 574,000	Electrical and construction-related materials
Total Equipment and Material	**$ 1,930,000**	

Source: California Energy Commission

Table 8: Engineering, Construction, and General Overhead Costs for a 350 kg/day Delivered Liquid HRS

Linde - Hydrogen Refueling Station - San Ramon	
Activity	**Cost ($)**
Site Engineering and Design	$ 50,000
Permitting	$ 31,000
Construction	$ 599,000
Commissioning	$ 76,000
Project Management and General Overhead	$ 117,000
Activity Sub-total	$ 873,000
Total Equipment (Table 7)	$ 1,930,000
Total Installed Cost (All-In)	**$ 2,803,000**

Source: California Energy Commission

As shown, equipment costs total about $1.9 million, while permitting, construction, project management, and overhead add nearly another million dollars. Total installed costs for this particular station are about $2.8 million.

Operations and Maintenance (O&M) Costs: As with the delivered gaseous stations, there are very few operational liquid delivery systems in California from which to draw operating cost information. Linde's West Sacramento station has been open for about 10 months, and initial O&M invoices are just now being received at the Energy Commission. Linde has been operating the AC Transit bus fueling station in Emeryville for many years, although it is configured for some on-site generation of renewable hydrogen and only needs to fuel at 350 bar pressure. Some informative operating cost data are available from the O&M grant for this station.

Delivered Cost of Hydrogen: Based on O&M invoices from the AC Transit bus fueling depot in Emeryville, liquid hydrogen is being delivered for about $9 to $10 per kilogram.

Lease Payments: One company has submitted an O&M invoice with lease payment information from a nonurban station site. While informative, the $2,600 monthly payment may not reflect urban, core market real estate values.

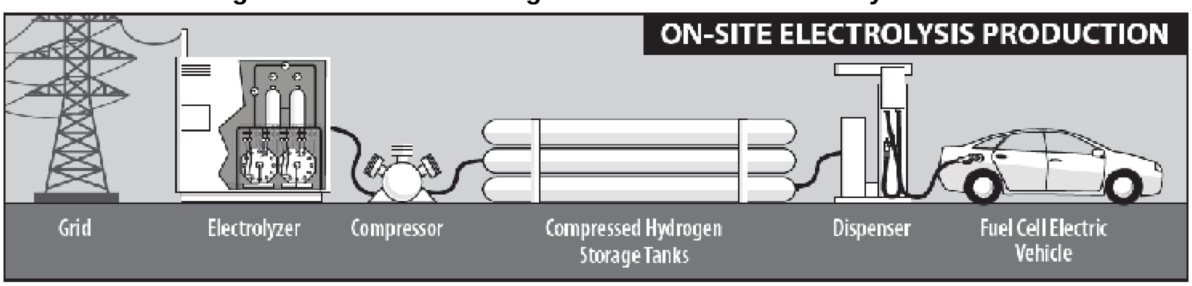
Maintenance Costs: Based on only one company's submitted invoicing, monthly maintenance costs seem to range from $800 to $1,500 per kg. A full preventative maintenance review of a station can cost more than $4,000.

On-Site Hydrogen Generation with Electrolysis

The third major category of hydrogen fueling stations in California features the on-site generation of hydrogen from water using electrolysis. Seven of the current 49 Energy Commission-funded stations are using this technology. These stations range from 100 to 140 kg/day, which puts them in the "coverage" category of stations appropriate for early market development.

Electrolysis is the process for splitting water molecules (H_2O) into the basic constituents of hydrogen and oxygen using an electric current. It uses the same chemical principles as a hydrogen fuel cell, but in reverse. After the electric current breaks the bonds between hydrogen and oxygen molecules atoms in the water, the hydrogen gas is captured and transferred to a pressurized tank for storage. The oxygen may also be captured for beneficial use. The gaseous hydrogen is then boosted to 350 or 700 bars of pressure for vehicle fueling. Figure 13 shows the schematic diagram and process flow for the major equipment elements of a typical on-site electrolysis HRS.

Figure 13: Schematic Diagram of an On-Site Electrolysis HRS



Source: NREL

Electrolysis-derived hydrogen tends to have a lower carbon intensity value than delivered gaseous or liquid hydrogen created through steam reforming. When 100 percent renewable electricity is directly linked to hydrogen production, the resulting hydrogen fuel can have a carbon intensity value of 0.0 gCO2e/MJ.[20] In contrast, delivered gaseous hydrogen with one-third renewable hydrogen (as required by California law for publicly funded HRS) has a carbon intensity value of 35.5 gCO2e/megajoule (MJ), while delivered liquid hydrogen has a carbon intensity value of 44 gCO2e/MJ.[21,22]

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20 Low Carbon Fuel Standard Pathway HYGN-006 for AC Transit's electrolysis station using 100 percent renewable electricity, http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/act-emca-110515.pdf

21 Energy Commission-ARB staff-derived carbon intensity values for delivered gaseous and liquid hydrogen, assuming one-third renewable hydrogen and an energy efficiency ratio (EER) of 2.5. (ARB defines the EER as "the ratio of the number of miles driven

Electrolysis uses water at an approximate 3:1 ratio of water to hydrogen, or 3 gallons of water per kilogram of hydrogen. This ratio ranged from 2.4 to 4.5 in proposals received for electrolysis stations.

On-site hydrogen generation eliminates the need for hydrogen transport with pressurized tank trailers. Since most California HRS are within existing gasoline stations, this on-site production reduces the potential for traffic congestion within the fueling station.

Electrolysis systems benefit from modular designs and scalability. All equipment can be designed for placement into 20- or 40-foot ISO containers.[23] This has the potential to reduce station construction costs. The H2 Logic company from Denmark is using this approach in Europe.

Several station developers and technology providers are using electrolysis, including ITM Power, HTEC Hydrogen Technology and Energy Corporation (HTEC), and HyGen Industries. ITM is a technology and station developer, while companies such as HyGen, HTEC, and H2 Frontier are developers that aggregate equipment from various suppliers. The Hydrogen Business Unit of Shell Oil Products U.S. operated a small capacity electrolysis station in Santa Monica for technology validation.[24] This station was closed in 2014. All-in costs for an on-site electrolysis station funded through the Energy Commission range from $2.7 million to more than $4 million.

HyGen Industries is developing three electrolysis stations in California through its grant awards in 2014. Tables 9 and 10 show equipment and construction costs for a HyGen station. These costs were derived from the public bid information submitted to the Energy Commission in response to PON-13-607 and then confirmed in a series of follow-up interviews.

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per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel." http://www.arb.ca.gov/fuels/lcfs/100609lcfs_updated_es.pdf.)

22 For comparison, battery electric cars using California grid electricity have a CI value of 30 gCO_2e/MJ. The gasoline baseline is 99.8 gCO_2e/MJ. Source: ARB LCFS Look Up Table, 2015.

23 ISO containers are enclosed steel shipping containers used for intermodal freight and storage, and are standardized via the International Organization for Standardization (ISO).

24 Shell built three demonstration-scale hydrogen stations in California in the 2000s. These include the pipeline station in Torrance, the on-site steam reformer station in Newport Beach, and the electrolysis station in Santa Monica. All three have been in continuous use. The Torrance station is being upgraded through an ARFVTP grant with the South Coast Air Quality Management District, while the Santa Monica station was recently closed.

Table 9: Equipment List and Estimated Cost for a Typical 130 kg/day On-Site Electrolysis HRS

HyGen - Hydrogen Refueling Station - Rohnert Park		
Equipment List	**Delivered Cost ($)**	**Notes and Specifications**
Ground Storage	$ 217,000	84.6 kg at 450 Bar - 12 tubes
High Pressure Tubes	$ 54,000	14 kg at 700 Bar - 2 tubes
Electrolyzer	$ 1,309,000	15 Bar
Compressors	$ 151,000	For 350 Bar
	$ 112,000	700 Bar booster
Dispenser	$ 388,000	350/700 Bar Dispenser & Chiller, includes Point of Sale
Chiller	$ 19,000	Pre-Chiller for High Pressure
Connection to Utilities*	$ -	*No cost due to direct connection on the property.
Misc. Material and Equipment	$ 134,000	Electrical and construction-related materials
Total Equipment and Material	**$ 2,384,000**	

Source: California Energy Commission

Table 10: Estimated Engineering, Permitting, Construction, and General Overhead Costs for a 130 kg/day On-Site Electrolysis HRS

HyGen - Hydrogen Refueling Station - Rohnert Park	
Activity	**Cost [$]**
Site Engineering and Design	$ 50,000
Permitting	$ 30,000
Construction	$ 463,000
Commissioning	$ 185,000
Project Management and General Overhead	$ 100,000
Activities SUBTOTAL	$ 828,000
Total Equipment (Table 9)	$ 2,384,000
Total Installed Cost	**$ 3,212,000**

Source: California Energy Commission

The total estimated installed cost for a HyGen electrolysis station is just more than $3.2 million,[25] which includes about $1.3 million for the electrolysis device. While this is higher than the installed costs for a delivered gaseous hydrogen station of $2 million and a delivered liquid hydrogen station of $2.8 million, the station-level costs for delivered hydrogen do not reflect the central station processing costs nor the tube trailer fabrication or delivery costs. These costs are included in the “compression” or wholesale delivery costs to the station.

Operations and Maintenance Costs

Operations and maintenance costs for on-site electrolysis are expected to be different from those of the delivered hydrogen stations. The key difference is likely to be the electrolysis

25 Paul Staples, President of HyGen Industries, believes that electrolysis station costs could be reduced by eliminating the 700-bar fueling standard. Staples has advocated this position at numerous public workshops hosted by the California Energy Commission over the past few years.

system power which is in addition to the power needed for the chilling and compression equipment.

A key challenge for electrolysis station developers is to secure the lowest possible rate from their local utility. This rate class is the most important cost element for electrolysis station developers and is a key determinant in how many years it will take a station to reach positive cash flow.

At present, the Energy Commission does not have confirmed information on which rate classes are being made available to electrolysis station developers. Preliminary information indicates that rates could range from 15 to 20 cent per kilowatt hour for commercial rates to 5 to 7 cents per kilowatt hour for industrial rates.

Comparison of the Major Cost Elements for Three Station Types

Table 11 shows the major cost elements for the delivered gaseous 180 kg/day station, delivered liquid 350 kg/day station, and the 130 kg/day electrolysis station.

Table 11: Comparison of the Major Cost Elements for Three Station Types

<table>
<tr><th colspan="4">Estimated Hydrogen Station Equipment Costs for Three Predominant Systems in California</th></tr>
<tr><th rowspan="2">Equipment List</th><th colspan="3">Delivered Cost ($)</th></tr>
<tr><th>FirstElement</th><th>Linde</th><th>HyGen</th></tr>
<tr><td>Ground Storage (gaseous or liquid)</td><td>$ 370,000</td><td>$ 92,000</td><td>$ 217,000</td></tr>
<tr><td>High Pressure Tubes</td><td>$ 135,000</td><td>$ 113,000</td><td>$ 54,000</td></tr>
<tr><td>Electrolyzer</td><td></td><td></td><td>$ 1,309,000</td></tr>
<tr><td rowspan="2">Compressors</td><td>$ 270,000</td><td>$ 778,000</td><td>$ 151,000</td></tr>
<tr><td></td><td>$ 12,000</td><td>$ 112,000</td></tr>
<tr><td>Chiller</td><td>$ 150,000</td><td rowspan="2">$ 294,000</td><td>$ 19,000</td></tr>
<tr><td>Dispenser</td><td>$ 270,000</td><td rowspan="2">$ 388,000</td></tr>
<tr><td>Point-of-Sale System</td><td>$ 20,000</td><td>$ 25,000</td></tr>
<tr><td>Connection with Utilities</td><td>$ 12,000</td><td>$ 42,000</td><td>$ -</td></tr>
<tr><td>Tubing and Valves</td><td>$ 150,000</td><td rowspan="2">$ 574,000</td><td rowspan="2">$ 134,000</td></tr>
<tr><td>Misc. Material and Equipment</td><td>$ 230,000</td></tr>
<tr><td>Total Equipment and Material</td><td>$ 1,607,000</td><td>$ 1,930,000</td><td>$ 2,384,000</td></tr>
</table>

<table>
<tr><th colspan="4">Estimated Total Hydrogen Station Costs for Three Predominant Systems in California</th></tr>
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<tr><th>FirstElement</th><th>Linde</th><th>HyGen</th></tr>
<tr><td>Site Engineering and Design</td><td>$ 23,300</td><td>$ 50,000</td><td>$ 50,000</td></tr>
<tr><td>Permitting</td><td>$ 14,300</td><td>$ 31,000</td><td>$ 30,000</td></tr>
<tr><td>Construction</td><td>$ 280,000</td><td>$ 599,000</td><td>$ 463,000</td></tr>
<tr><td>Commissioning</td><td>$ 35,700</td><td>$ 76,000</td><td>$ 185,000</td></tr>
<tr><td>Project Management and General Overhead</td><td>$ 54,500</td><td>$ 117,000</td><td>$ 100,000</td></tr>
<tr><td>Activity Sub-total</td><td>$ 407,800</td><td>$ 873,000</td><td>$ 828,000</td></tr>
<tr><td>Total Equipment</td><td>$ 1,607,000</td><td>$ 1,930,000</td><td>$ 2,384,000</td></tr>
<tr><td>Total Installed Cost (All-In)</td><td>$ 2,014,800</td><td>$ 2,803,000</td><td>$ 3,212,000</td></tr>
<tr><td colspan="4">**Docket comments from Linde Oct 2015 say that their costs are 10% more than a 180 kg/day GH2</td></tr>
</table>

Source: California Energy Commission

The varying costs for equipment and installation activity indicate the differences in the three technology packages and the approaches each company takes in developing an HRS. For example, the FirstElement/Air Products System receives gaseous hydrogen at high pressure, resulting in more costly ground storage vessels. Linde's IC90 ionic compressor was developed specifically for use in its liquid delivered hydrogen systems and is well regarded in the industry. The other compressors tend to come from third-party vendors with a more established fabrication process. Despite the higher equipment costs for the 350 kg/day liquid delivery system over the 180 kg/day gaseous delivery system, the Linde equipment is less expensive on a levelized $ per kg basis.

The FirstElement cost estimates for permitting and construction may be lower due to the higher volumes of stations being developed with a shorter period (19 in all) and the already established construction practices developed by Air Products for the initial 180 kg/day stations.

Potential for Cost Reductions

Over time, hydrogen station equipment costs should decline as equipment packages are standardized, larger stations are developed, equipment is produced at higher volumes, and station developers learn more efficient methods to integrate and install equipment. These types of lessons or experience cost reductions are well-documented and occur across a broad range of energy and other technologies.[26] A key variable for potential cost reductions is the global demand for HRS. While the 100 HRS scheduled for installation in California may not be large enough to trigger economies of scale cost reductions, the cumulative HRS equipment demand from projects in the Eastern United States, Europe, and Asia may be sufficient to begin pushing costs down.

The resulting capital costs from technology lessons and global-scale HRS development are shown in Figure 14 for the three main station types. (Please see Appendix C for additional technical descriptions for the cost reduction analysis.) The 100 kg/day electrolysis, 180 kg/day GH2 truck, and 350 kg/day LH2 truck stations are shown in the figure in the time series lines with triangle, circle and square symbols, respectively. The costs are shown decreasing over time starting in 2017 and ending in 2025. The trend for a fourth station type, large HSCC 600 kg/day, is also indicated declining from $4.25 million to $2.5 million between 2017 and 2025.

Values for HRS capital costs based upon recent Energy Commission awards are shown as points with the same symbols by type and with nominal installation dates between 2015 and 2016. Refer to Figure 14 for capital cost by station type over time.

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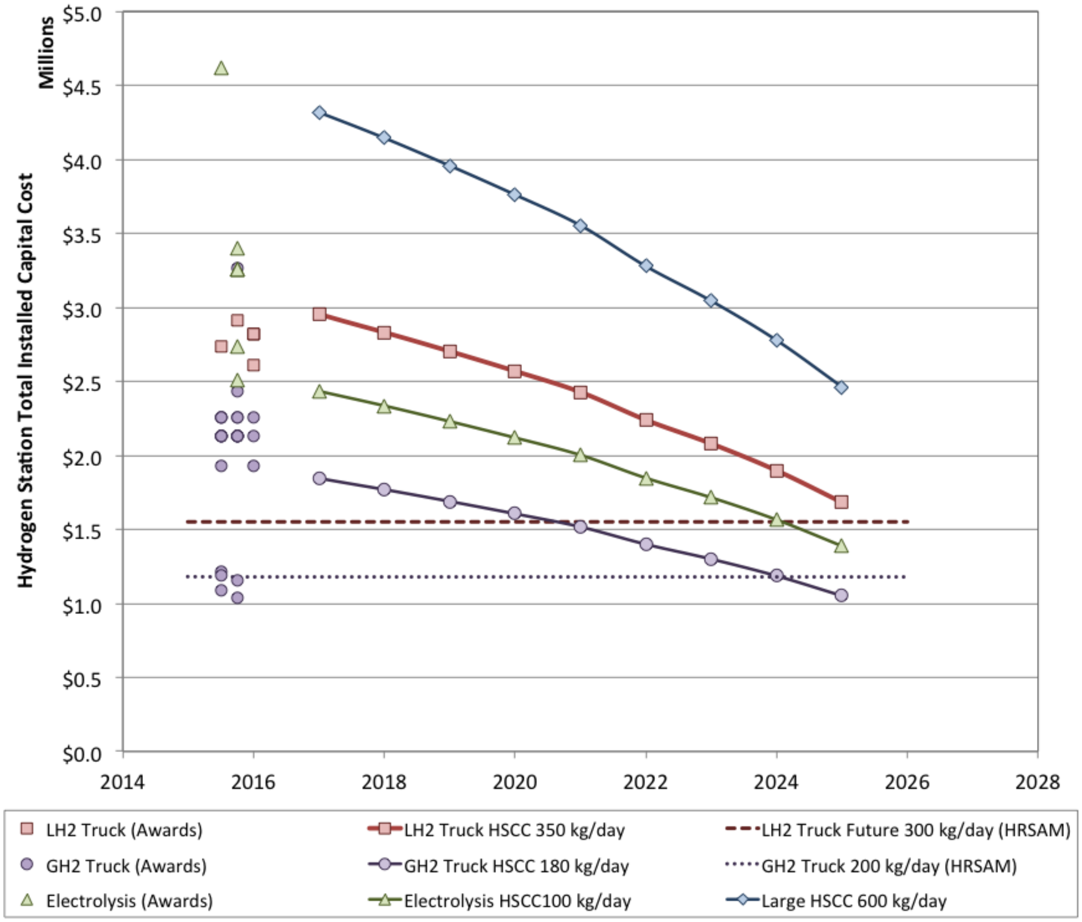
26 Wene, Clas-Otto. 2000. *Experience Curves for Energy Technology Policy*. Paris: Organization for Economic Co-operation and Development, International Energy Agency. Available at: http://www.wenergy.se/pdf/curve2000.pdf

Figure 14: Capital Costs by Station Type over Time



Source: NREL

Role and Effect of New Business Models and Private Investments

Automaker Investments in Hydrogen Infrastructure

Until the 2014 ARFVTP grant awards, the standard business model for hydrogen station development was for energy companies, primarily industrial gas companies or IGCs, to self-finance the capital and operating costs of a station and then to match that private capital with government incentive grants. This changed in 2013 when Toyota announced that it was providing a long-term loan of $7.2 million to FirstElement, Inc., marking the first direct investment by a FCEV automaker in California retail HRS. Honda made a similar announcement in 2014 of a $12 million line of credit to FirstElement. Toyota then announced a similar loan package to Air Liquide to begin developing 12 HRS on the East Coast.

FirstElement Fuel used the Toyota capital to pay for a larger portion of its total per-station capital costs. While total costs did not change, FirstElement offered about $500,000 more in private capital per station than other station development companies. This, in turn, substantially reduced the government cost per station, which resulted in more HRS per public dollar. FirstElement won $25 million in total grant incentives for 19 new stations, or $1.4 million per station. If FirstElement had won $25 million for the full possible grant incentive of $2.1 million per station, it would have obtained enough funding for about 12 new stations. The Toyota investment in First Element resulted in 7 additional stations, raising the total number of awarded stations in 2014 to 29 rather than 22. This increased private investment is substantially accelerating hydrogen station development in California.

Chapter 6 explores several scenarios in which the hydrogen fuel cell vehicle and fueling markets have matured sufficiently to attract private capital investments seeking industry standard rates of return.

Automaker Investments to Reduce Consumer Fueling Costs

Another stream of automaker investments in early market FCEVs is the payment of hydrogen fuel costs for consumers. While this was a standard part of the lease agreements with FCEV consumers during demonstration deployments by Mercedes, Honda, Nissan, and Toyota, it is being extended to the early market commercial consumer leases offered by Hyundai and Toyota, and most likely by Honda as well in 2016.

These automaker fuel subsidies will be important in buffering early adopter consumers from the high early market hydrogen fuel prices. Using some basic assumptions, this early market fuel subsidy can be roughly estimated.

Assuming 0.7 kg of fuel per vehicle per day, an FCEV would use about 255 kg per year. At $14 per kg, this would average $3,570 per year in fuel costs. Assuming 1,000 FCEVs in California by the end of 2016, this would total about $3.5 million annually if the automakers were to pay the full fuel price. However, it is more likely that there is a cost-sharing agreement with the hydrogen station operators, and the fuel price subsidy is lower. Toyota currently offers a three-year fuel subsidy.

This fuel price subsidy also benefits station developers and operators by increasing the potential for higher vehicle and fuel sales in early years and decreasing the number of years that station developers will incur negative gross revenues.

Additional Government Financial Support for HRS

In addition to the Energy Commission's administration of AB 8 funding for HRS, other state and regional agencies have and are contributing to development of HRS in California. These supplemental investments in HRS projects in California total $28.1 million to date.

ARB Hydrogen Station Investments

The ARB invested a total of $15.7 million for eight technology demonstration HRS in the 2000s. These stations tended to be smaller, ≤100 kg/day stations that were built and operated to demonstrate gaseous delivery systems, liquid delivery systems, and on-site generation using

SMR and electrolysis. These stations provided fuel for the early demonstration fleets of FCEVs offered by Nissan, Toyota, General Motors, Daimler, and Honda and proved out technologies leading to the current retail configurations. These stations will be upgraded to larger capacity stations or gradually phased out and decommissioned.

South Coast Air Quality Management District

The South Coast AQMD has invested $13.2 million to date through its Clean Fuels Program. These investments include $10.1 million in co-funding for the first 5 Cities Technology Demonstration HRS in California and for the 8 ARB-funded Technology Demonstration HRS in the 2000s. South Coast AQMD has provided an additional $3.1 million in supplemental capital and operating expense support to the modern network of HRS in Southern California between 2010 and 2014. These grants average about $125,000 per station and range from $100,000 to $200,000.

Bay Area Air Quality Management District

The Bay Area AQMD provided a total of $2.2 million in 2015 in supplemental capital and operating support for 12 HRS projects in the San Francisco Bay Area. The goal of the supplemental grants was to accelerate development and completion of the 12 HRS funded by the Energy Commission. Although the greater San Francisco Bay Area is expected to be an important FCEV market, station development has lagged behind Southern California HRS projects. The AC Transit Emeryville station offers both bus and light duty passenger vehicle hydrogen refueling. Emeryville is co-located with the bus depot and is also a stand-alone light-duty vehicle refueling station. In addition, other stations are in development as shown in Figure 1.

CAETFA Manufacturing Sales and Use Tax Exemption Program

SB 71 created a sales and use tax exemption program for companies involved in green manufacturing in California. The California Alternative Energy and Advanced Transportation Financing Authority (CAETFA) administers the program, which provides credit support, sales and use tax exclusion, and access to low-cost financing through private, activity-exempt bonds, loans, and other forms of financial assistance. At present, only the generation of hydrogen and renewable hydrogen qualifies as a manufacturing or production process. To date, two companies have qualified for SB 71 tax exemption grants for hydrogen production or HRS equipment. Presumably, all on-site hydrogen generation projects using electrolysis or on-site SMR will qualify.

IBank Financial Resources for Hydrogen Fuel Production and Small Businesses

Created in 1994 under GO-Biz, the California Infrastructure and Economic Development Bank (IBank) finances public infrastructure and private development through a variety of programs. The California Lending for Energy and Environmental Needs (CLEEN) Center encourages private and public investment in projects that meet State objectives to conserve water, reduce greenhouse gas emissions, and generate clean and renewable energy. Eligible projects may include hydrogen stations, energy storage, and transmission and distribution. Direct Loan

CLEEN Center Program funding is available in a range of amounts ranging from $500,000 to $30 million, or more with Board approval. In the Small Business Loan Guarantee Program (SBLGP), IBank partners with Financial Development Corporations (FDCs) to guarantee loans made by Financial Institutions, with guarantees up to 80 percent that provide incentives for lenders to make loans to small businesses.

CHAPTER 5: Comparing Hydrogen Prices to Gasoline Prices

Retail hydrogen prices are important to station operators and FCEV consumers. For the station operator, retail sales at a given price are the primary means to recover costs incurred for operations, maintenance and capital. For consumers, their perspective on hydrogen fuel prices will factor into their decision on whether to purchase an FCEV. This chapter places the price of hydrogen into context by drawing comparisons to the fuel costs associated with conventional and hybrid electric gasoline vehicles. Chapter 6 examines the role of hydrogen prices in the context of station financing and the role of Energy Commission subsidies in supporting the growth of the California HRS network.

Early market retail hydrogen prices range from $12.85 per kg to $16.49 for 700 bar fueling. A common price is $13.99 per kg. Fills at 350 bar tend to be priced about $2 less per kg compared to 700 bar fills.

Hydrogen Fuel Price Levels Will Be a Factor in Consumer Responsiveness to FCEVs

The price of hydrogen to consumers will be determined by retail station owners based upon marketing strategies, business models, underlying financial conditions, and competitive market forces. Given the strong role of utilization in determining the economics of stations, it is not unreasonable to expect high prices while stations are underutilized as local demand grows. During the first few years of vehicle introductions (2015-2020), retailers will likely not be able to charge prices that reflect the true economics of a station in a given year, as those prices would be unacceptable to most FCEV drivers. If the average price of hydrogen in a city, neighborhood, or other geographically confined market is too high, new FCEV sales may be depressed, dampening future demand growth and reducing the rate of growth in revenue across the network. The retail price of hydrogen is therefore a complex issue that influences both the financial health of stations and sales of FCEVs. Given these countervailing tendencies between the need to cover actual costs and prices deemed acceptable to consumers, HRS retailers face a challenge in determining how to set retail prices in the near term.

FCEVs Are More than Twice as Efficient as Gasoline Power Vehicles

One way to estimate what might be an acceptable retail price for FCEV drivers is to calculate the equivalent price of driving a conventional gasoline or hybrid electric gasoline vehicle on a per-mile-driven basis. When estimating comparable per-mile fuel prices with gasoline used in conventional gasoline vehicles (CGVs), a general rule of thumb is that FCEVs are expected to be about twice as efficient as conventional gasoline vehicles. In other words, FCEVs can drive twice as far as a CGV given the same fuel energy, provided as gasoline to the CGV or as hydrogen to the FCEV. This means that if gasoline is priced at $3.50 per gallon, the per-mile equivalent price for hydrogen would be twice that on an energy basis, or $7.00 per kg of hydrogen (a gallon of gasoline has roughly the same energy content as a kg of hydrogen), and the fuel cost per-mile would be the same given that those $7 are spread across twice as many miles driven.

This ratio of 2 for the fuel economy of FCEVs compared to that of CGVs is an approximate rule of thumb. Examples of actual calculations that are similar to this rule of thumb are shown below, with gasoline priced at $3.50 per gallon for a 27 mpg gasoline vehicle and hydrogen priced at $8.00 per gge (or kg) for a 65 mpgge FCEV. Results are shown in units of dollars per mile driven. In this case, the fuel economy ratio would be 2.4 (65 mpgge divided by 27 mpg).

$$\frac{\$3.50\ per\ gal\ gasoline}{27\ miles\ per\ gal\ gasoline} = \$0.13/mile$$

$$\frac{\$8\ per\ kg\ hydrogen}{66\ miles\ per\ kg\ hydrogen} = \$0.12/mile$$

Reflecting current hydrogen fuel prices in California of about $14 per kg, per mile costs to consumers are 21 cents per mile:

$$\frac{\$14\ per\ kg\ hydrogen}{66\ miles\ per\ kg\ hydrogen} = \$0.21/mile$$

At $3.50 per gallon gasoline and $8.00 per kg hydrogen, the fuel cost per mile is nearly identical. However, this may not be apparent to drivers or potential FCEV adopters, who see only the posted retail prices of gasoline at $3.50 per gallon and hydrogen at $8.00 per kg. Moreover, potential FCEV buyers may be interested in comparing not only current fuel prices and vehicle fuel economies, but projected fuel prices and fuel economies of vehicles that may be offered in future years.

To better understand how hydrogen prices will compare to gasoline over time as station utilization rates increase and more efficient vehicles arrive in showrooms, it is insightful to compare projections of fuel price trends and fuel economies into the future. The values for new vehicle fuel economies and the ratio of FCEV to CGV are shown in the first three lines of Table 12. These values are larger than 2 but begin to approximate 2 as CGV fuel economies improve relative to FCEV fuel economies. (Fuel economy values are from the ARB VISION study.) The fourth row in the table indicates gasoline price trends by year. Multiplying these prices by the fuel economy ratio gives the price that hydrogen could be charged to consumers to incur identical fuel costs per mile as they would have paid if driving a CGV on gasoline. This value is shown in the fifth row and is referred to as the Gasoline-Equivalent Hydrogen Price. As indicated in the final row, the average prices assumed to be charged across the HRS network over time are higher than the Gasoline-Equivalent Hydrogen Price but approach the Gasoline-Equivalent Price by 2025. The financial implications of charging these prices to recover the various costs discussed in previous sections are discussed in the next chapter.

Table 12: New Vehicle Fuel Economies, Fuel Economy Ratios, Gasoline Fuel Prices, and Gasoline-Equivalent Hydrogen Prices

Attribute	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Vehicle Fuel Economies (mpgge)											
New Fuel Cell Electric Vehicle (FCEV)	72	74.1	77.6	79.3	81.4	83	85.3	87.3	88.9	90.8	93.3
New Conventional Gasoline Vehicle (CGV)	28.6	29.8	31.6	32.7	33.9	35.1	36.5	37.8	39.1	40.4	42.1
Fuel Economy Ratio (FCEV/CGV)	2.52	2.49	2.46	2.43	2.40	2.36	2.34	2.31	2.27	2.25	2.22
Fuel Prices											
Gasoline Price ($/gal)	$2.89	$3.35	$3.54	$3.63	$3.75	$4.01	$4.15	$4.32	$4.48	$4.64	$4.81
Gasoline-Equivalent Hydrogen Price ($/kg)	$7.28	$8.33	$8.7	$8.8	$9.00	$9.48	$9.71	$9.97	$10.19	$10.43	$10.66
Hydrogen Price used in Scenario Analyses ($/kg)	$14.00	$13.71	$13.42	$13.13	$12.85	$12.56	$12.27	$11.98	$11.69	$11.4	$11.11

Source: NREL, derived from the ARB VISION model (2015)

CHAPTER 6: Estimates of Future Costs and Time Needed to Reach 100 HRS

Introduction

As discussed in the previous chapter, the cost of supplying hydrogen to FCEVs is expected to decline over time as station utilization rates increase and as new stations achieve cost reductions through lessons, larger capacities, economies of scale, mass production of infrastructure equipment, and retail competition. Economies of scale are also anticipated in hydrogen production and delivery infrastructure, reducing the cost of supplying hydrogen to stations. At the same time, FCEV technology is expected to improve, resulting in improved performance, lower manufacturing costs, and increased fuel economy. Reduced vehicle production costs and fuel costs per mile can result in a virtuous cycle of accelerated market adoption, strengthening the outlook for future hydrogen demand and reducing uncertainties associated with investments in hydrogen infrastructure. The requirements of hydrogen supply infrastructure in this market development process are to provide reliable, convenient, and affordable hydrogen for early adopters of FCEVs.

This chapter summarizes NREL's analysis of the potential role of Energy Commission subsidies in reducing retail hydrogen prices while improving the financial outlook for the first 100 stations in the California HRS network. NREL developed a scenario approach to examine various factors influencing future HRS network development, hydrogen price, and retail station financing. NREL used the Scenario Evaluation, Regionalization, and Analysis model (SERA) to define and analyze the scenarios. These results provide insights into the sufficiency of ARFVTP incentives for establishing a self-sustaining HRS network.

The three scenarios are summarized in Table 13 below. These scenarios assign stations into three groups:

Group 1 stations denote the 51 stations currently open or that are funded and in construction.

Group 2 stations denote the additional 49 stations needed to reach the 100 station milestone.

Group 3 stations denote the stations beyond the first 100 that will be needed to meet ever-growing demand for hydrogen fuel.

One additional scenario that is not analyzed, the baseline scenario, is a reference for inadequate HRS development: the steady rollout of stations at a rate of seven per year out to 2023 with the current incentive funding levels used by the Energy Commission. Similar to the portrayal in the June 2015 ARB report, the present analysis suggests that this baseline scenario would fall short of expected hydrogen demand in the 2020-2021 period. The same total levels of Energy Commission incentives are applied in all three scenarios, though with different mixes of capital and O&M incentives in different years according to variations in the station deployment schedules. The goal of the scenario analysis is to better understand the potential influence of Energy Commission incentives if applied to a large number of HRS to satisfy near-term hydrogen demand, and how the Energy Commission might modulate incentives in response to market signals of higher or lower FCEV adoption rates.

The scenarios are all based on the 2015 ARB automaker survey, which projects 300 FCEVs by the end of 2015, 10,500 FCEVs by the end of 2018, and 34,300 by the end of 2021.

Table 13: Summary of Three HRS Development Scenarios

Expected Scenario *(demand matches ARB projection)*
• The HRS network capacity expands quickly to meet hydrogen demand in the near term, with incentives for 100 HRS by 2020. • Vehicle adoption rates match those reported in the June 2015 ARB report.
Delayed Scenario *(demand grows much more slowly than ARB projection)*
• Vehicle adoption rates are significantly slower than those reported in the June 2015 ARB report, due either to unforeseen problems with the HRS network development or less than anticipated consumer response to FCEVs. FCEV adoption is slowed by four years from current ARB survey of estimated total sales by 2023. • The Energy Commission modulates incentives as the HRS network expands quickly at first to meet expected demand through 2018-2019, and then slowly in response to the delayed demand, with 100 HRS by 2024.
Robust Scenario *(demand grows more rapidly than ARB projection)*
• Vehicle adoption rates exceed those reported in the June 2015 ARB report, with vehicle sales rate being one year ahead of expected sales by 2023. • The Energy Commission modulates incentives as the HRS network expands more quickly to meet hydrogen demand, with 100 HRS by 2020.

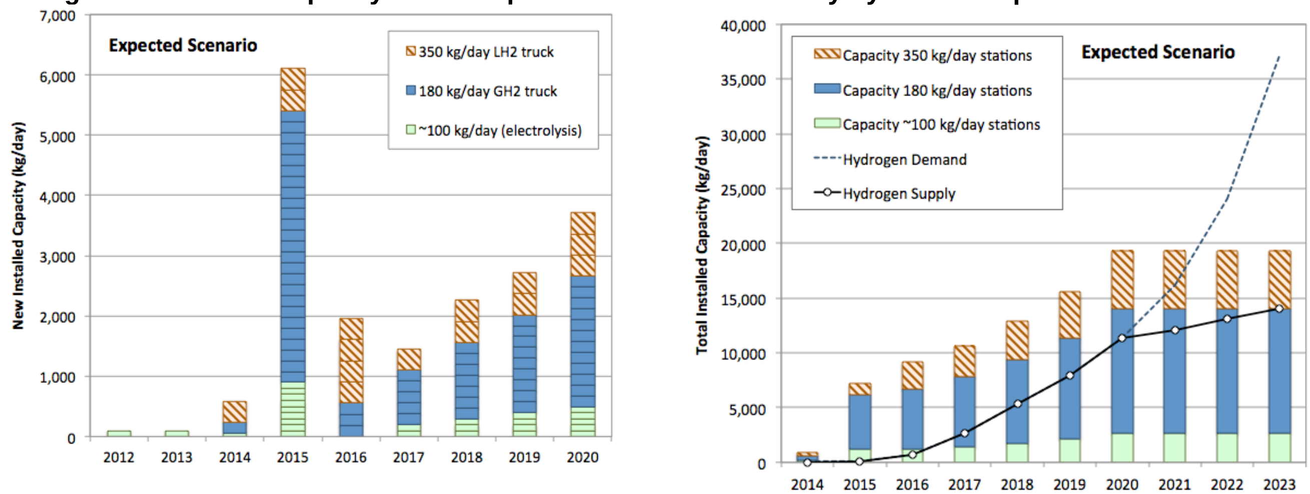
Source: NREL

In each of the three scenarios, more HRS are provided state capital and O&M incentives earlier in time than in the baseline development rate of seven stations per year through 2023. Station development occurs with the same ratio of coverage and capacity level-stations currently being developed. Most are 180 kg/day stations, with a steady series of smaller electrolysis stations and larger liquid delivery 350 kg/day stations. During the early market introduction period for FCEVs covered in this report, it is assumed that the maximum average utilization across the network is 75 percent of nameplate capacity.

A more detailed view of the stations installed over time by capacity is shown for the Expected scenario in Figure 15. The left-hand panel shows the number of stations installed per year, with bar heights indicating station capacity. The right-hand panel shows the same information cumulatively over time.

Please see Appendix for a more complete description of how the scenarios are developed.

Figure 15: Station Capacity Installed per Year and Cumulatively by Size in Expected Scenario



Source: NREL

HRS Network Development Scenario Results

The three HRS network scenarios illustrate a range of FCEV adoption rates and corresponding station development rates between 2015 and 2025. In all the scenarios, AB 8 incentives are critical to jump-starting the hydrogen fuel market in the early years as it is important that there always be available fueling opportunities and capacities for potential new FCEV customers.

A key finding is that ARFVTP funds are only a small fraction of the total investment required to establish a HRS network with sufficient capacity to satisfy the hydrogen demand projection to 2025 based on the ARB survey results. Moreover, positive financial performance of the first 100 HRS will be critical to stimulating additional private sector investments.

Expected Scenario Results

The Expected Scenario shows the HRS network expanding to a total capacity of just over 19,500 kg/day, with 100 HRS installed by 2020 as the network grows in response to the increasing numbers of FCEVs projected by the current ARB survey. As shown in Figure 16, about 7,000 kg in new capacity is added in 2015, reflecting development of the current 51 stations in Group 1. New capacity is added steadily between 2016 and 2019 as the Group 2 stations are developed, while in 2020, a larger block of capacity is developed with larger stations as the network expands to match the increasing fuel demand created by the accelerating influx of FCEVs expected in 2020-2021. A total of $157 million in AB 118 and AB 8 funding is needed to reach the 100-station milestone.

As shown in Figure 17, the network utilization rate increases from 2 percent in 2015 through 40 percent in 2018, but does not reach the maximum 75 percent utilization rate until 2025. It is due to the very low utilization rates in the early years that the Energy Commission has created the operations and maintenance funding category of $100,000 per year for the first three years of operation.

Increasing levels of private capital are invested in the HRS network as the financial performance of the system improves and increasing levels of fuel demand are demonstrated. As shown in Figure 18 for the Expected Scenario, (upper left quadrant) half of the needed investment in 2020 is supplied by the private sector to match the maximum AB 8 funding allocation. This is more than the current private investment match rate of 15 percent but equivalent to the 50 percent match requirements typical in other fuel categories in ARFVTP. Market demand for fuel increases steadily from $80 million in 2021 to more than $400 million in 2025 (Figure 18).

Delayed Scenario Results

In contrast to the steady demand growth in the Expected scenario, total network fuel demand in the Delayed Scenario increases very slowly in early years and reaches only 15,000 kg/day in 2025. (Figure 16: demand from the Expected scenario is shown for comparison in the grey dotted line.) The Energy Commission begins slowing station funding in 2018-2019, and station capacity reaches a plateau of just under 10,000 kg/day for several years. Private investment matching funds remain low. Significant levels of new capacity do not begin to be installed again until 2021. The 100-station milestone is reached in 2024 with a smaller network capacity of 16,000 kg/day. A total of $170 million in AB 118 and AB 8 funding is needed. In this scenario, station development occurs in advance of FCEV deployment and adoption, and the station utilization rate grows slowly, reaching 30 percent in 2021 and only 60 percent in 2025.

As shown in Figure 18, market demand for fuel grows very slowly and reaches an $80 million annual market value in 2025.

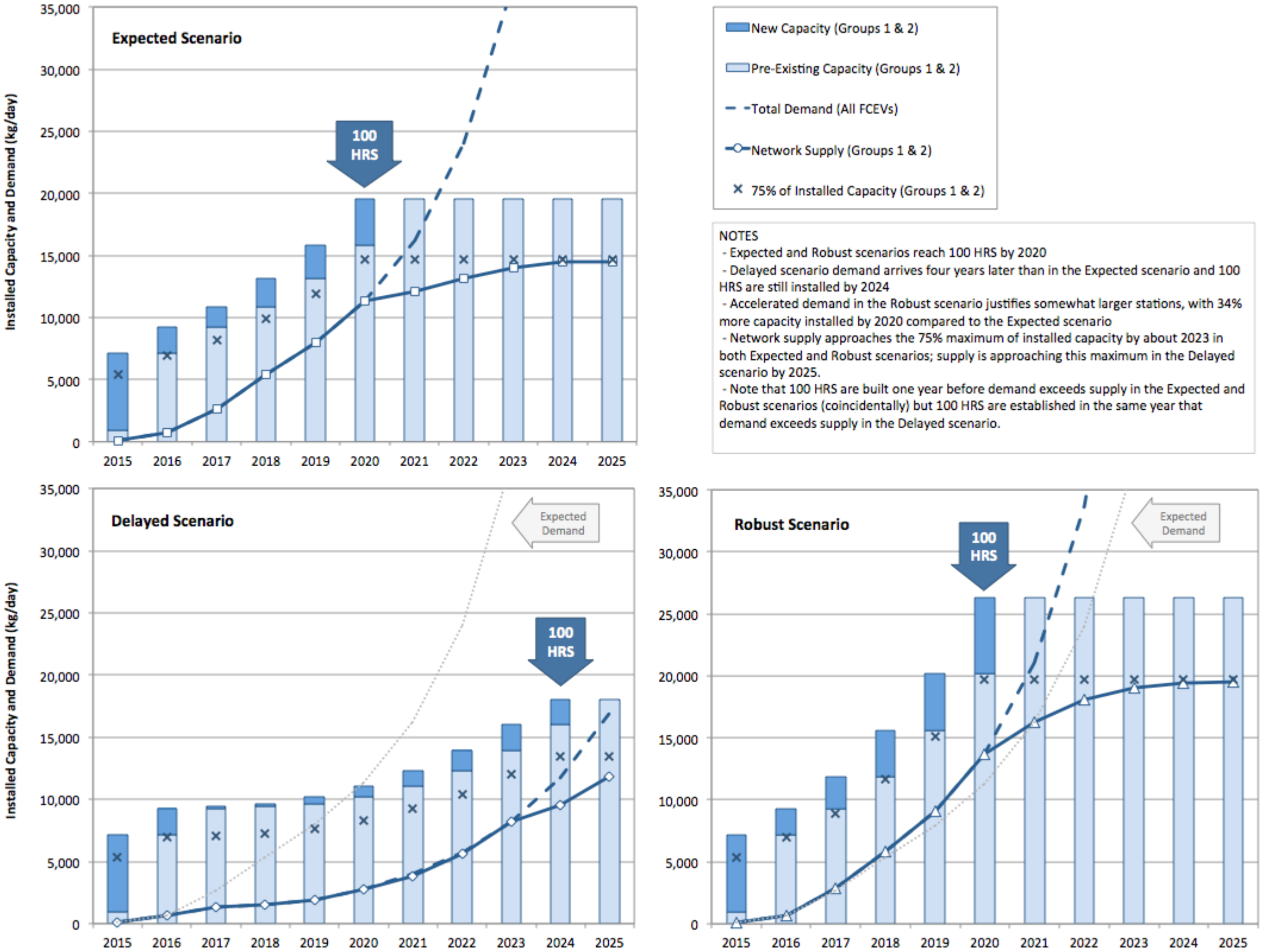
In this extreme case, it is assumed that the Energy Commission receives market signals suggesting FCEV market growth will be slow between 2015 and 2020. The Energy Commission responds very quickly to this change in market signals, attempting to avoid a large mismatch between installed capacity and market demand. Should a scenario such as this occur, government incentive funding would be needed throughout 2023 and likely beyond to continue supporting market development of FCEVs in California.

Robust Scenario Results

The Robust Scenario illustrates strong consumer acceptance of FCEVs by accelerating vehicle deployment into California one year earlier than the Expected Scenario. The HRS network expands quickly to 100 stations in 2020 with a larger system capacity of 26,000 kg/day (Figure 16). Larger stations are bid into the system in core markets as developers and investors see the potential to build larger and more cost-effective stations in California. More than 10,000 kg of new capacity are developed in 2019 and 2020 to keep pace with surging fuel demands.

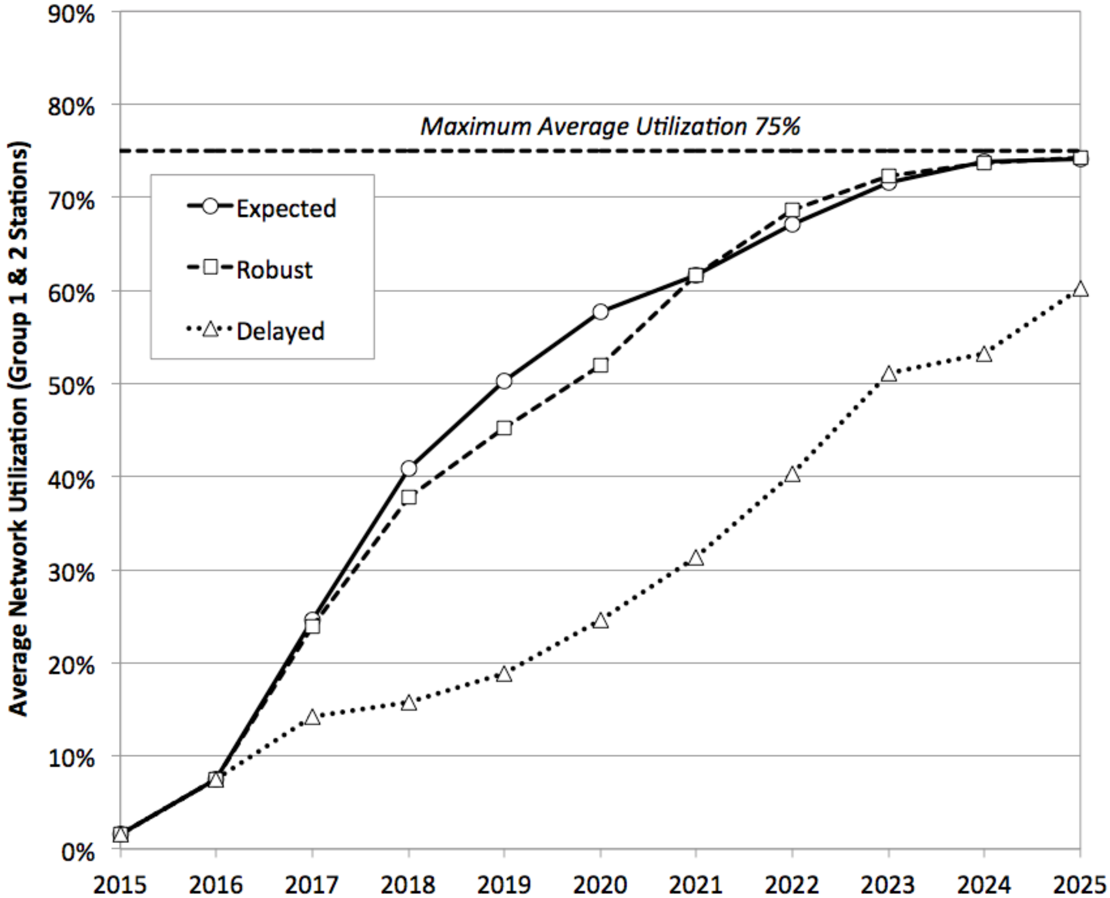
Total AB 118 and AB 8 investments to support this scenario would total $157 million by 2020. Due to the $20 million per year funding constraint imposed by AB 8, larger amounts of private investment are assumed to enable the rapid build-out of station capacity needed to keep pace with market demand. As shown in Figure 18, private investment would need to match public investment in 2019 and then exceed the 2020 public investment of $19.5 million by $28 million to keep pace with growing demand for fuel. Private investment is drawn to the California HRS network as investors perceive the growing market demand. The hydrogen fuel market grows aggressively from $100 million per year in 2021 to more than $800 million per year in 2025 (Figure 18).

Figure 16: Comparison of Capacity and Supply from Groups 1 and 2 Stations to Total Network Demand



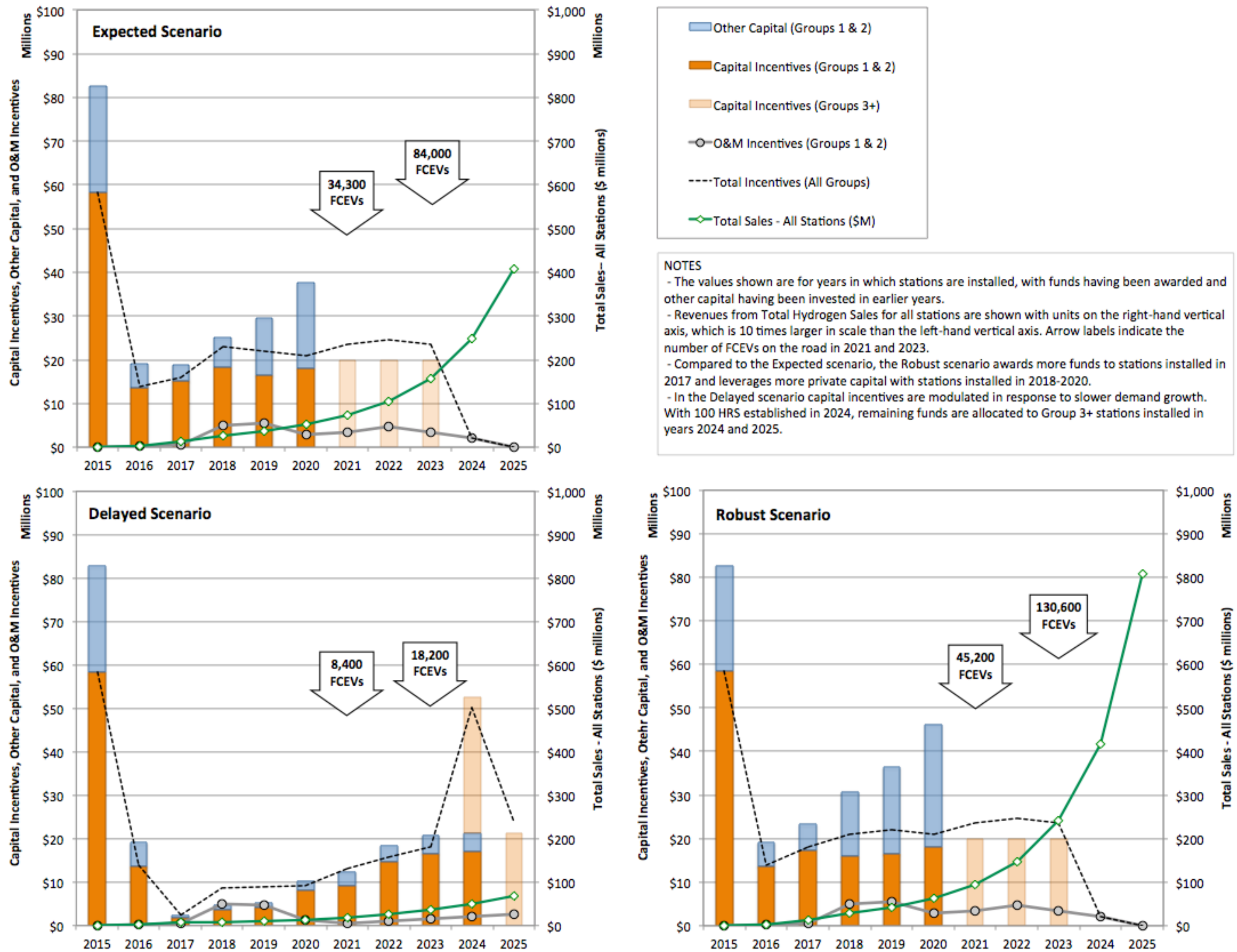
Source: NREL

Figure 17: Projected Average HRS Utilization Rate under Three Scenario Conditions



Source: NREL

Figure 18: Levels of Government Funding and Private Capital Needed to Meet Growing Market Demand in Three Scenarios of FCEV Deployment and Early Market



Source: NREL

Evaluation Summary: State Incentives are Critical to Jump-Starting California's Hydrogen Fueling Market in the Early Years in All Scenarios

Each of the three scenarios illustrates the need to invest State incentive funding early in market development so that FCEV consumers and automakers do not see shortages in hydrogen fuel supplies. Put another way, the HRS network needs to be built and operational before automakers can release vehicles to new markets in Los Angeles, Orange County and the San Francisco Bay Area. The Energy Commission's high incentive funding levels of 85 percent of capital costs plus three years of operations and maintenance funding enable station developers to operate stations without incurring substantial levels of negative revenues and debt. Even with these high incentive funding levels, Figure 17 shows the slow build-up of hydrogen sales and station utilization rates through 2020 to 2025, indicating the ongoing need for incentive support in all scenarios.

The Delayed Scenario illustrates the challenges with slow station build-out and FCEV deployment in California. Higher percentages of AB 8 funding (compared to private investment) are required to keep the HRS operational through the end of the AB 8 funding program to compensate for the low fuel sales volumes, and private capital never expands beyond the current 15 percent minimum level required by the Energy Commission.

The Expected and Robust Scenarios illustrate the potential for rapid market growth with larger amounts of private capital being invested in 2019 and 2020. More economical, larger capacity stations can be constructed in core markets in Los Angeles and Silicon Valley, where higher fuel volumes would be needed to match the growing numbers of FCEVs. But even in 2020 in the Robust Scenario (lower right quadrant of Figure 18), the level of private investment needed is roughly equal to the available State funding level of $19 million. This is not an unrealistic outcome because 50 percent capital match is the standard Energy Commission match requirement for most other alternative fuels and fueling infrastructure. Between 2021 and 2025 however, private capital will need to enter California's HRS market well beyond the levels depicted in Figure 18 to keep pace with escalating fuel demands.

This need for additional investments in the HRS network in 2020 and beyond illustrates the critical need for Groups 1 and 2 stations to exhibit positive financial performance to the investment community in the 2019-2020 period. This positive financial performance is enabled by the Energy Commission's large investments of AB 8 funding early in market development when total numbers of vehicles are low and station utilization levels are low. As fuel demand grows through 2020 and beyond, the highly subsidized initial HRS network will be in a stronger financial condition to stimulate the higher levels of private investment that will be needed to keep pace with the rapid growth projected by ARB and the FCEV automakers. Future market fuel demand levels for the Expected Scenario grow rapidly from $80 million in 2021 when 34,300 FCEVs are expected to more than $400 million in 2025 when more than 84,000 FCEVs could be expected (assuming a similar growth rate). Future fuel demand levels are more dramatic for the Robust Scenario, as the fuels market grows from $100 million annually in 2021 to serve more than 45,000 FCEVs to more than $800 million in 2025 to serve more than

130,000 FCEVs. These scenarios present attractive market potentials to future investors (see Figure 18).

In summary, ARFVTP funds are only a small fraction of the total funds required to establish a HRS network with capacity sufficient to meet demand projections to 2023. Moreover, it is the early ARFVTP investments in Groups 1 and 2 stations that will likely prove critical to stimulating private sector investment by exhibiting positive financial performance.

Over the long term, the current levels of incentive funding created through AB 8 will not be sufficient to continue subsidizing hydrogen refueling stations at a rate that can keep pace with the level of market growth needed to meet ZEV mandate goals. Looking ahead to 2023 when AB 8 is scheduled to expire, the Energy Commission and ARB will need to closely monitor the pace of FCEV deployment and HRS development to ensure that there is sufficient fueling capacity and coverage to serve a growing FCEV market, as well as needed levels of capital investments.

Scenario Financial Assessment

To further assess the degree to which public funds are needed to establish an initial HRS network, and the degree to which private sector funds may be relied upon to expand that network to meet future hydrogen demand from FCEVs, the Energy Commission and NREL used the H2FAST model to assess possible growth scenarios for the California HRS network. [27] NREL developed H2FAST to analyze future financial market conditions and financial performance of HRS at the network and station level. While more traditional engineering economics methods have typically been relied upon to estimate future hydrogen supply costs, the H2FAST framework builds upon cost estimating methods to generate standard financial reports (balance sheet, income statement, cash flow) as well as several financial metrics of interest to different parties, such as the banking and investment sectors, (internal rate of return, net present value, debt-to-equity ratio, and so forth.) to assess investment potential and risk.[28]

A wide range of financial metrics are generated from the H2FAST financial framework. For the present scenarios, a subset of six financial metrics are examined to better understand to what degree the HRS network has become "established" from the perspective of different stakeholders. The first stakeholder is the funding organization, primarily the Energy Commission in this case, who is interested in each funded project and the entire HRS network becoming viable from a business perspective such that they can persist into the future without

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27 The term "public funds" is used here to indicate incentives provided by the Energy Commission or other government agencies. "Private sector funds" refers to equity investments, but may also include debt instruments such as loans or bonds.

28 The U.S. Department of Energy's Hydrogen Analysis (H2A) suite of models is a commonly used, engineering-based cost estimation approach for hydrogen stations and infrastructure components. (See http://www.hydrogen.energy.gov/h2a_analysis.html). The H2FAST framework, developed for the U.S. DOE by NREL, builds upon the H2A suite of models. (See the H2FAST website: http://www.nrel.gov/hydrogen/h2fast, User's Guide: http://www.nrel.gov/docs/fy15osti/64020.pdf, and 2015 Annual Merit Review presentation: http://www.hydrogen.energy.gov/pdfs/htac_apr15_08_melaina.pdf.)

continued government support. Financial metrics of greatest interest from this perspective are *operating profit, net profit,* the *profitability index*, and *net investor cash flow,* with the profitability index being applied only to nominal stations and the others being applicable to both stations and the entire HRS network. Station owner or private equity investors are also interested in this same set of metrics, though *gross margin* may also be of interest given that it is comparable to the gross margin metric used in the retail gasoline market. Finally, from the perspective of lending organizations such as banks, the ability to service debt is of key interest and is measured through the *debt-service coverage ratio*. These are generalized tendencies; each metric may be of greater or lesser interest to these and other stakeholders. Table 14 provides an explanation of the key financial metrics.

The H2 FAST model has been populated with the cost and price information available from the Energy Commission's 49-station dataset. Other inputs are described more fully in the Appendices.

Table 14: Explanation of key financial metrics

Net Profit ($/kg and $)
Total revenues after depreciation, interest, taxes, or other business expenses. Also referred to as net income, total earnings, or the bottom line because it appears at the bottom of the income statement. Unlike operating profit (below) net profit accounts for both capital and total operating expenses (CAPEX and OPEX). Net profit can be distributed to shareholders or retained by the business. Consistently high levels of net profit are likely to attract investors. Net profit may be reinvested into new stations
Operating Profit ($/kg and $)
Total operating revenue minus cost of goods sold (COGS) and other operating expenses (OPEX). Operating revenue is due to everyday or regular revenue from inventory sales, rather than unique events. COGS is direct costs associated with producing hydrogen, while other OPEX are incurred as a result of normal business operations apart from producing hydrogen. Total operating expenses includes both types of expenses. Positive operating profit indicates that a business can remain in operation. Also referred to as Earnings before Interest, Taxes and Depreciation (EBITD).   Operating Profit ($) = Operating Revenue – COGS – OPEX
Gross Margin ($/kg)
Total revenue minus cost of goods sold (COGS), divided by total hydrogen sales in kg for units of $/kg. Gross margin is the total revenue (hydrogen price in $/kg multiplied by total sales in kg, minus credit card charges) retained after incurring the direct costs associated with producing hydrogen, or COGS, which is defined as total operating expenses + depreciation + interest – selling and administrative expenses. Including depreciation expense in COGS follows the convention of gasoline fuel margins reported by OPIS.[a] High positive gross margin represents the revenue per kg a HRS can use to service other costs and obligations. Also referred to as gross profit, and reported as a percentage when dividing by total revenue instead of hydrogen sales.   Gross margin ($/kg) = (Total Revenues $ – Cost of Goods Sold $)/(Hydrogen Sales kg)
Profitability Index (PI)
The ratio of the net present value (NPV) of future cash flows divided by private equity invested to date. A PI of 1 indicates break-even, and higher ratios indicated higher levels of profitability. Assuming a project life of 20 years, a PI result of 2 is comparable to an internal rate of return (IRR) of 10%.   Profitability Index = (NPV of future cash flows $) / (Initial equity invested to date $)
Equity Investor Net and Cumulative Cash Flow ($)
Equity Investor Cash Flow is the net amount flowing between the business and the equity investor. Positive cash generated by the operation of the business is in excess of any liquidity requirement for business operation and cannot be applied gainfully within the business. This cash is dispersed to the equity investor. Negative cash flow indicates that the business is short on cash from operating activities, and requires infusion of cash for capital or operating purposes. Net cash flow projects individual year's cash flow to the equity investor, while cumulative cash flow projects the sum of all cash flows through the reporting period.
Debt-Service-Coverage Ratio (DSCR)
The ratio of net operating income divided by debt obligations due within one year. A DSCR greater than 1 indicates that a HRS has sufficient income to service debts. Banks are interested in DSCR to understand ability to service loans.   Debt-Service Coverage Ratio (DSCR) = (Net Operating Income $) / (Total Debt Service $)

Notes: OPIS fuel margins are calculated as retail price minus taxes, wholesale price, and freight. See OPIS Retail Fuel Pricing and Margins (http://www.opisnet.com/resources/OPIS_RetailPricingBrochure.pdf).

Source: NREL

Critical Role of Hydrogen Cost and Price in the Financial Analysis

Building upon the projections of total capital costs and annual O&M costs in Chapter 4, as well as station capacity and utilization rate projections discussed in Section 6.2, there are two additional key input assumptions that are fundamental to the business case of future retail HRS networks and stations:

Hydrogen Price. This term is used to represent the price of hydrogen charged to consumers refueling at public HRS.

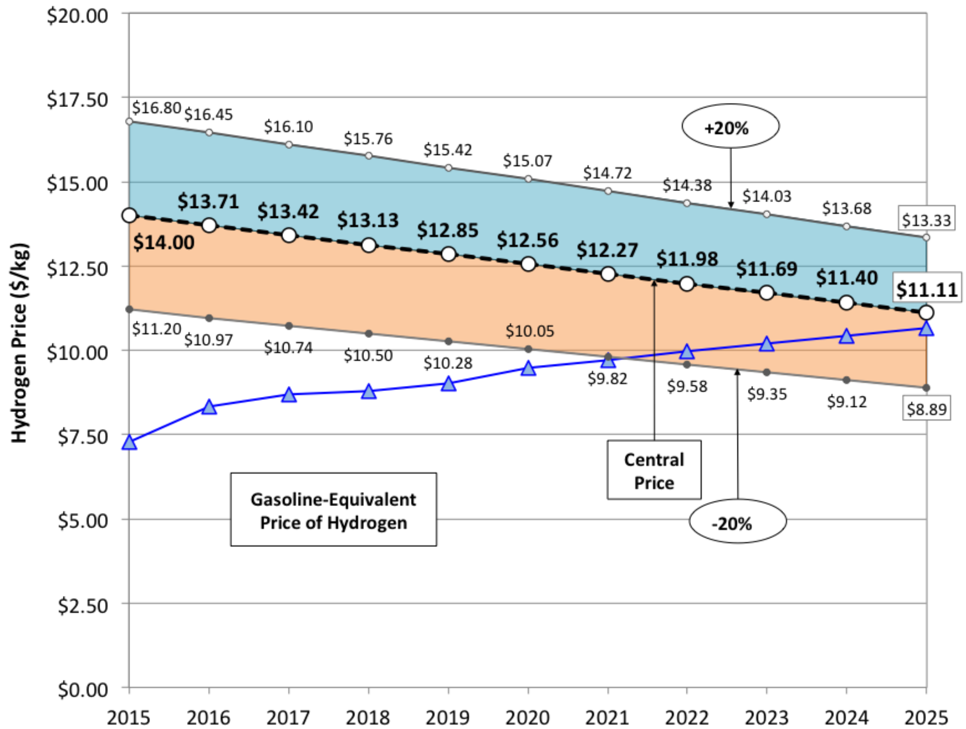
Delivered hydrogen cost. For stations receiving delivered hydrogen, such as from a truck or pipeline, this term represents the cost of the delivered hydrogen. It is also the price charged to HRS owners by the entity delivering the hydrogen to the station. In the case of onsite electrolysis or SMR stations, the counterpart is the feedstock cost of electricity or natural gas required to produce hydrogen.

The difference between hydrogen price and delivered cost may be the most relevant and most difficult to project into the future with any degree of precision. The difference between the cost of acquiring hydrogen for a station (either delivered to the station by tank truck or produced onsite) and the price paid by consumers at the pump determines the revenue that must cover all expenses involved in owning and operating a station. There are other important factors taken into consideration in the present analysis, such as depreciation of capital equipment and interest rates, but this gap between delivered hydrogen cost and hydrogen price largely determines the business viability of retail stations.

As an input to this analysis, a fixed and linearly declining hydrogen price is assumed for all three scenarios. The gasoline-equivalent hydrogen price serves as a reference for what may prove to be an acceptable retail hydrogen market price over the long term. However, it is likely that many different pricing regimes may be employed by different retailers in response to both local market conditions (for example, what the market will bear).

The assumed price of hydrogen for the present analysis is shown in Figure 19 as the Central Price, beginning at $14 per kg in 2015 and declining linearly to $11.11 per kg in 2025. The $14 per kg value in 2015 is considered typical of many stations in operation. The $11.11 per kg value is about 4 percent higher than the $10.66 per kg gasoline-equivalent hydrogen price in 2025. The gasoline-equivalent price, described in chapter 4, is the price of hydrogen equivalent to that of gasoline used in a new conventional gasoline vehicle, using the relative fuel economy of new FECVs and new ICEVs to determine equivalent fuel costs on a per-mile basis.

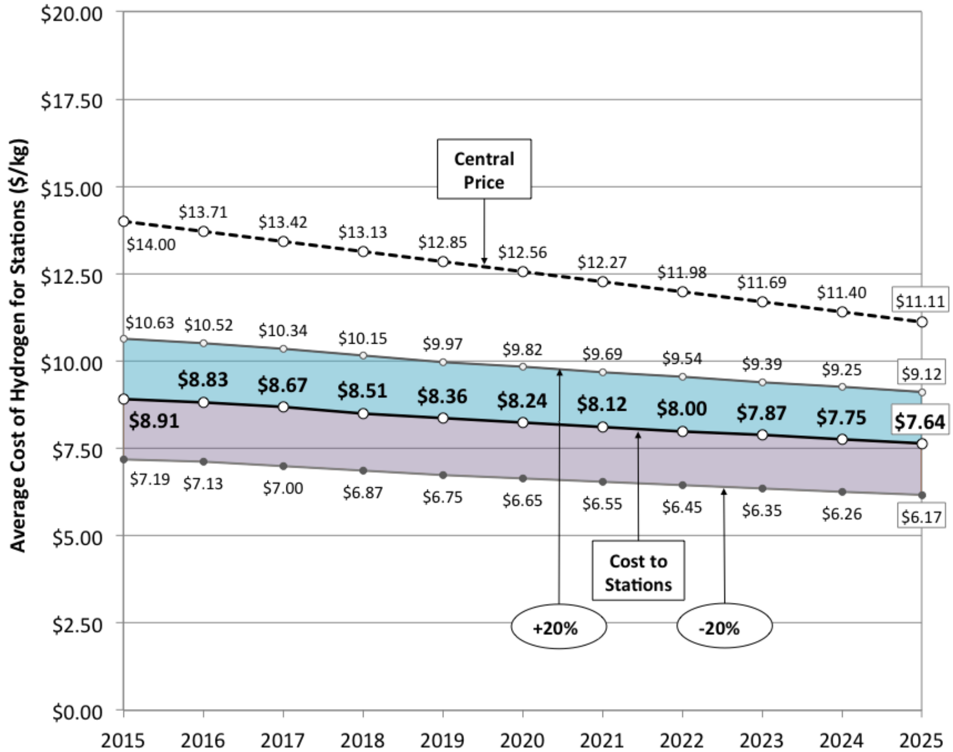
Figure 19: Comparison of Assumed Average Price of Hydrogen to Drivers (+/- 20 Percent) and Gasoline-Equivalent Price of Hydrogen



Source: NREL

Based upon internal Energy Commission records and delivery prices charged to existing fueling stations serving commercial fuel cell forklift facilities, it is assumed $8.50 per kg is a typical cost of hydrogen delivered by gaseous tank truck to retail station owners. As volumes increase and delivery networks begin to achieve economies of scale, and as suppliers begin to encounter increased levels of competition, this price is assumed to drop to $7.00 per kg by 2025. Taking into account the variations in cost due to electrolysis and LH2 truck delivery (see Appendix B), the resulting feedstock cost trend is indicated in Figure 20, with sensitivity bands representing variations of 20 percent more or less than the central cost trend. The central projected hydrogen price is shown for reference.

Figure 20: Average Cost of Gaseous Truck Hydrogen for Stations (+/-20 Percent)



Source: NREL

Significant cost reductions are possible for future production and delivery systems. For example, the U.S. Department of Energy estimates hydrogen production costs declining to $2-$5 per kg by 2015 and $2 per kg in the long term, and total delivery and retail dispensing costs to decline to $2 per kg over the long term and at high capacity.[29] More empirical data must be collected on the particular delivery systems serving northern and southern California to develop a more precise projection for the present statewide assessment.

As indicated, these two price trends begin to converge gradually over time. The spread between these two trends starts at $5.09 per kg in 2015 and narrows to $3.47 per kg by 2025. This narrowing of the central price and cost projections requires that HRS must operate with slightly less revenue per kg sold over the analysis period. However, the uncertainties around both price and cost are significant: both are subjected to a +/- 20 percent sensitivity in determining financial performance. Adding a +/- 20 percent uncertainty around HRS capital costs results in the full set of uncertainty cases shown in Table 15, with four demand scenarios having three

29 For information on the H2A delivery cost models, see footnote 28. For updates on the status of hydrogen production and delivery technologies, see Eric Miller (2015) Hydrogen Production & Delivery Program: Plenary Presentation, 2015 Annual Merit Review and Peer Evaluation Meeting, Washington, DC, June 8-12. Available at http://www.hydrogen.energy.gov/pdfs/review15/pd000_miller_2015_o.pdf.

central cases for capital costs, hydrogen cost, and hydrogen price, and +/-20 percent sensitivities around each of those cases.

Table 15: Uncertainties Cases Used in Financial Assessment

Demand Scenario	Capital Costs	Hydrogen Cost	Hydrogen Price
Baseline	Modified HSCC Estimate	Central Projection	Central Projection
Delayed	-20% of Estimate	-20% of Projection	-20% of Projection
Expected	+20% of Estimate	+20% of Projection	+20% of Projection
Robust			Gasoline Equivalent

Source: NREL

LCFS Credit Values for Renewable Hydrogen Can Help Build Station Revenues

The station financial evaluations discussed in this report include consideration of the value of LCFS credits that could be generated by the station owner or hydrogen producer through the sale of hydrogen. In the evaluations presented, the levelized LCFS credit value ranges from $0.18 to $0.50 per kilogram of hydrogen sold (the highest values being associated with the 100 percent renewable electrolysis stations). This LCFS credit presents a valuable opportunity in improving the financial case for HRS, especially the electrolysis-based stations. The values of LCFS credits assumed in these analyses have been conservative, in the absence of any hydrogen-related LCFS credit generation and trading in the historical record.

On November 16, 2015, the LCFS program certified the first pathway with an active participating entity.[30] AC Transit in Emeryville (Alameda County), applied for and received certification for its zero-carbon pathway for the production of gaseous hydrogen onsite, powered with 100 percent renewable solar power dedicated to generating hydrogen. This production method is used for the light-duty vehicle side of the fueling station at the AC Transit depot. (A second pathway is used to fuel a much larger volume required for the transit agency's fuel cell buses.) Using the carbon intensity value of zero of this pathway, accounting for the efficiency advantage of a FCEV captured by the Energy Economy Ratio of 2.5 and assuming a credit value of $100/MMT, an electrolysis station using 100 percent dedicated renewable electricity generation could potentially earn $2.71 per kilogram of hydrogen dispensed. This is substantially higher than the values assumed in the current financial analyses and presents the possibility for an improved financial case for this type of station. At $2.71 per kg, the LCFS credit value would actually be the third-largest contributor to station income (as opposed to fifth as shown in the scorecards). Average trading values reported by the ARB are $86 per credit as of November 2015, with a general upward trend over the preceding

30 http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/act-emca-sum-110515.pdf.

three months and over the previous three quarters.[31] The range of traded values for November was $22 to $105 per credit.

Results for the Profit, Gross Margin, and Debt Metrics for the Statewide HRS Network

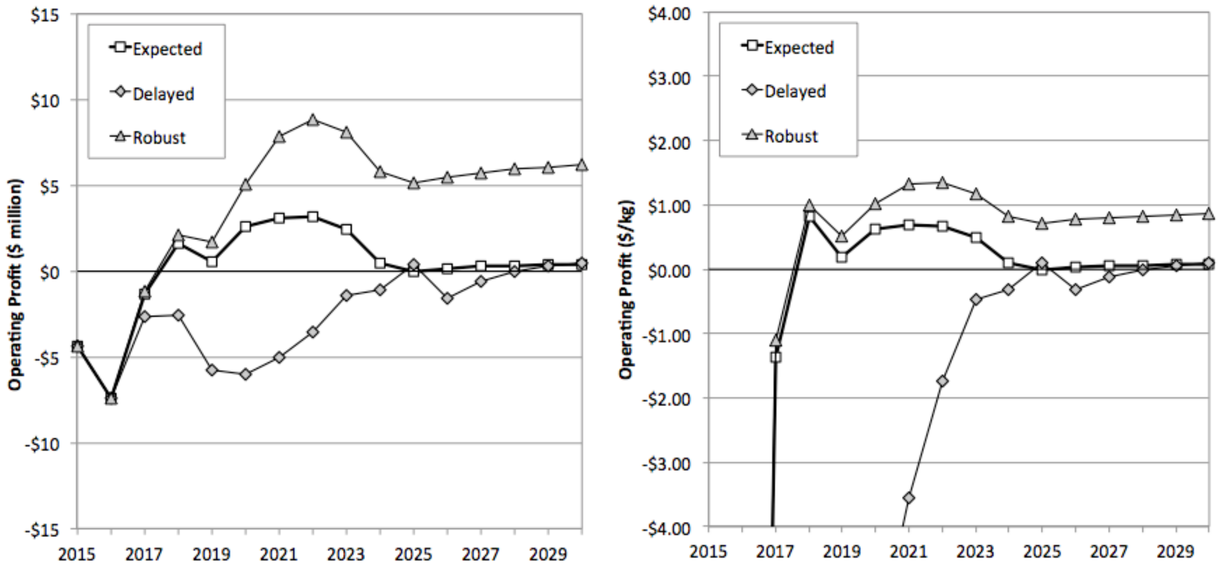
It is instructive to review a few financial metrics in terms of the central case with central projections and no sensitivities. The financial results for this central case are generally not favorable and suggest that establishing a self-sufficient HRS network would be challenging in all three scenarios, but would be easier to achieve due to the stronger demand and greater economies of scale in the Robust scenario. (As a reminder, stronger demand and larger stations are input assumptions in designing the Robust scenario.) The HRS network can appear to be favorable and self-sustaining in each scenario when the cost of delivered hydrogen is lower, the price charged to consumers is higher, or (to a more limited degree) when the capital cost of stations declines more quickly. Therefore, while the central case results are of interest, the sensitivity results must be consulted to understand how different metrics respond to these variables and to what degree they must change to result in a viable HRS network or station.

Results for Operating Profit with and without Sensitivities

The central results for operating profit are shown in Figure 21 in both units of millions of dollars and dollars per kg of hydrogen sold. Only the Robust scenario meets the threshold of positive operating profit through 2030. Results for the Expected Scenario show positive operating profit temporarily from 2020 to 2022, and the Delayed Scenario has negative operating profit throughout the analysis period. These central results suggest that the HRS network would not remain in operation in the Delayed Scenario, would only just stay in business temporarily in the Expected Scenario, and could remain open through 2030 in the Robust Scenario.

31 http://www.arb.ca.gov/fuels/lcfs/credit/20151208_novcreditreport.pdf.

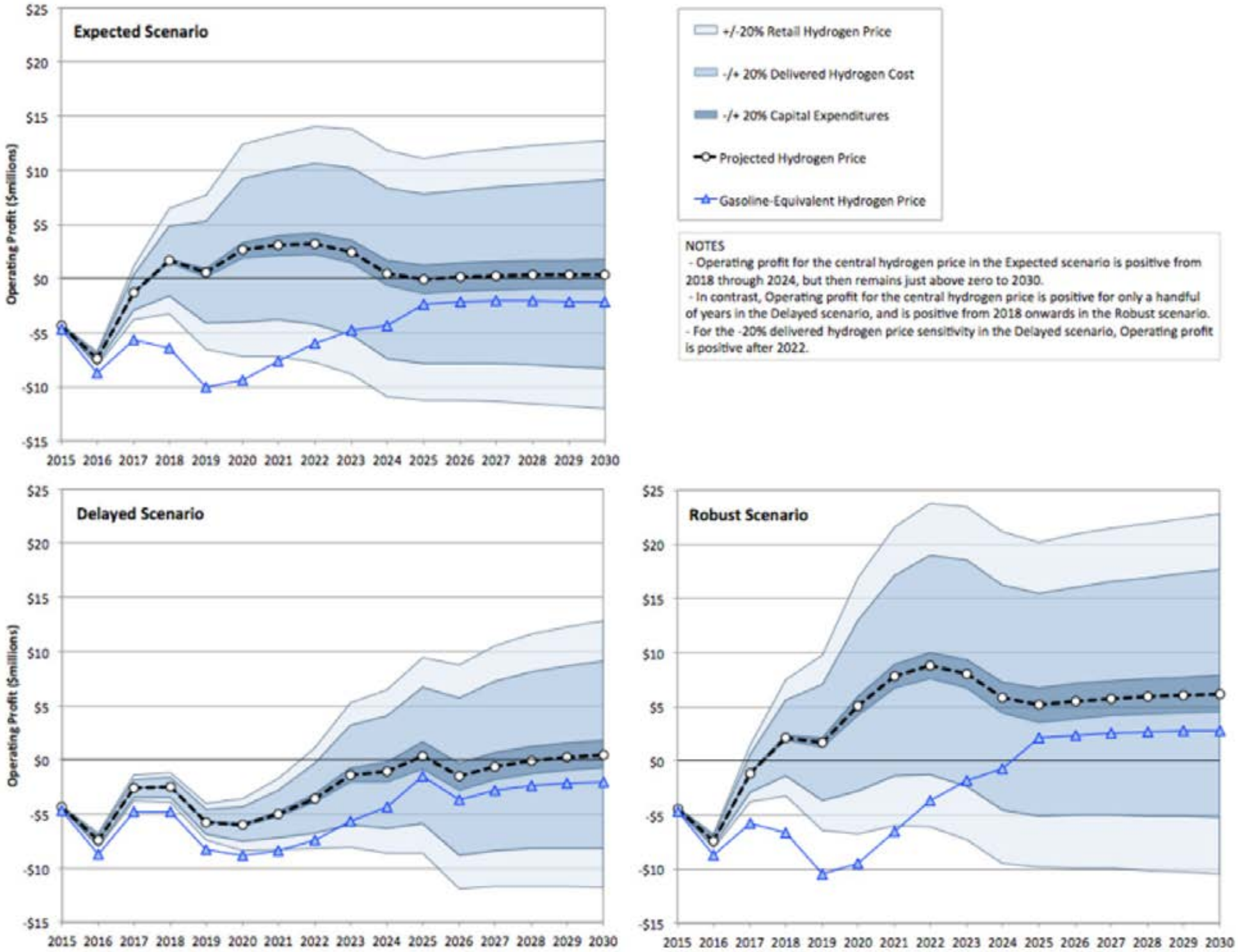
Figure 21: Operating Profit Results for the Central Hydrogen Price Projection in Each Scenario



Source: NREL

The results of sensitivities on operating profit are presented in Figure 22 in millions of dollars and in Appendix D in dollars per kg. As indicated, variations in capital costs have almost no effect on operating profits, while variations in hydrogen price and the cost of hydrogen have larger influences. With a 20 percent reduction in the cost of delivered hydrogen, the HRS networks in all three scenarios would remain in operation though 2030, though the Delayed scenario achieves only sustained positive operating profit starting in 2022. This is five years later than calculated for the Expected and Robust scenarios.

Figure 22: Sensitivity Results for Operating Profit for All Scenarios ($ millions)

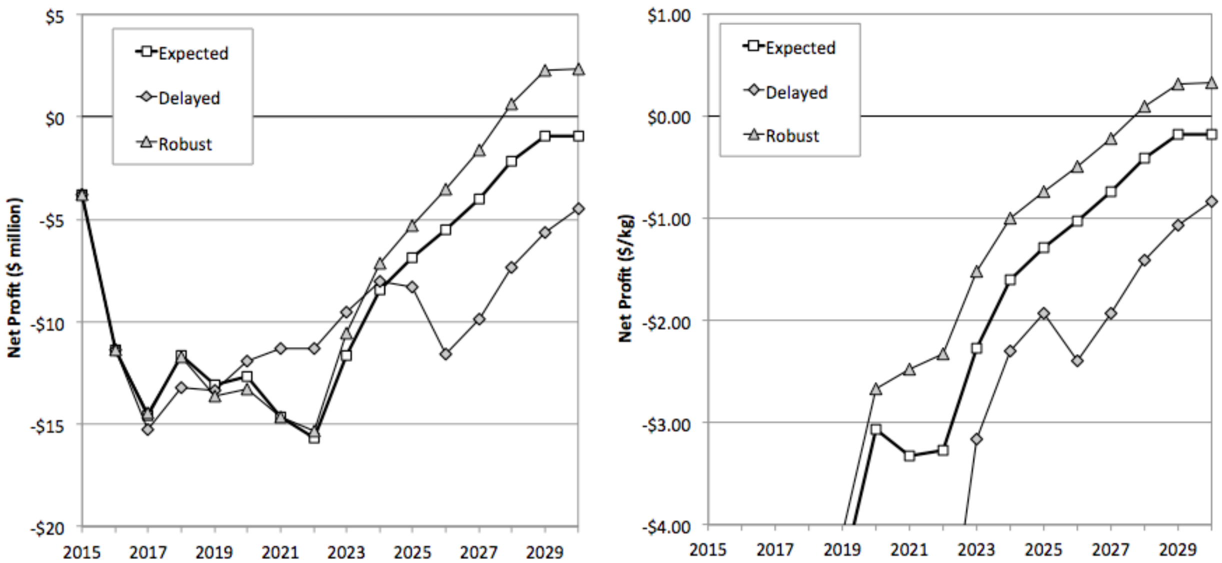


Source: NREL

Results for Net Profit with and Without Sensitivities

Central case results for net profit are shown in Figure 23. Only the Robust scenario achieves significant net profit before 2030, as the Expected scenario experiences a leveling off of steady negative net profit before 2030. This suggests that in the central hydrogen price case the HRS networks have either not become established and self-sustaining by 2030 (Expected and Delayed), or have just become self-sustaining (Robust). While net profit trends in the Expected scenario have leveled off at unfavorable levels by 2030, the Delayed scenario continues to increase but then also levels off at a negative net profit level after 2030 (not shown in figure).

Figure 23: Net Profit Results for the Central Hydrogen Price Projection in Each Scenario



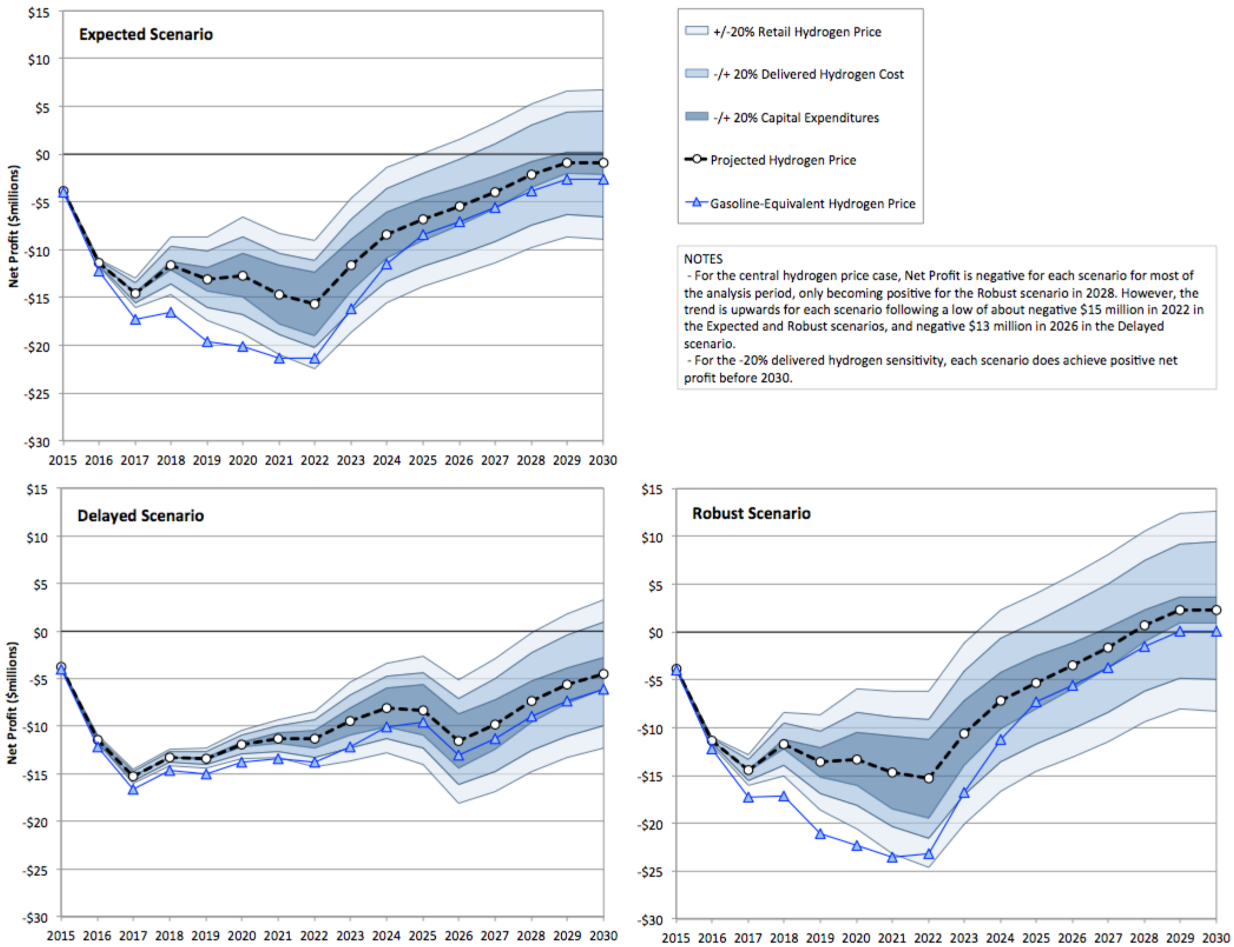
Source: NREL

Sensitivity results for net profit are shown in Figure 24 in millions of dollars and in $/kg in Appendix D. These results suggest that each scenario would become viable with a positive net income within the 2025-2030 time frame under the -20 percent delivered hydrogen cost sensitivity.

However, based upon positive results for the -20 percent delivered hydrogen cost sensitivity, a significant reduction in the delivered hydrogen cost (maybe 10 percent) could be enough to keep the network operating through 2025. These net profits are near $1 per kg by 2030 in the Expected and Robust scenarios.

Operating profit and net profit results suggest that HRS networks would be financially viable only in the case where some change increases revenue to stations above that of the central case. As a reference, a 20 percent reduction in the cost of delivered hydrogen (equivalent to about $1.50 per kg, see Figure 20) would be sufficient to make the HRS network viable in each scenario by 2030. Reductions in annual O&M costs over time, which are relatively conservative in the base case assumptions, could also result in increased revenue at this scale over the 2030 time frame.

Figure 24: Sensitivity Results for Net Profit ($ millions) for All Scenarios

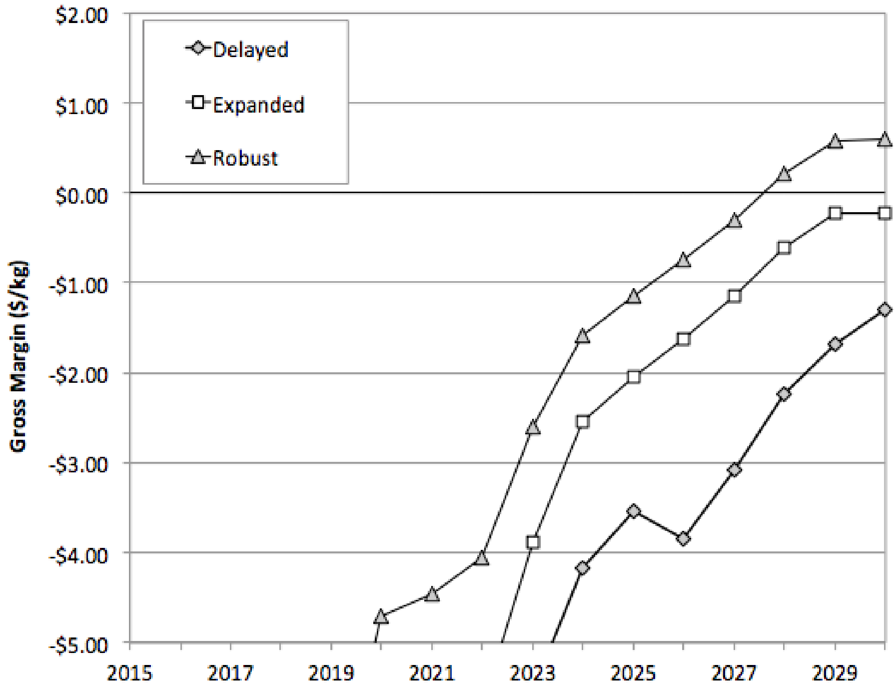


Source: NREL

Results for Gross Margin And DSCR with and Without Sensitivities

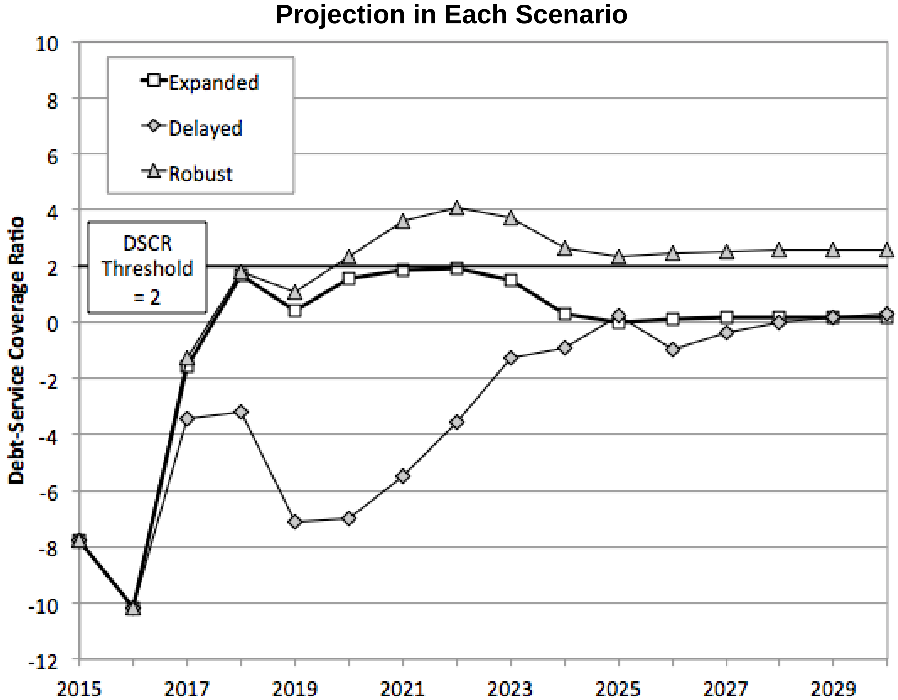
Central hydrogen price results for gross margin are shown as primarily negative over the analysis period in Figure 25, and the DSCR only exceeds the threshold of 2 in the Robust scenario, as shown in Figure 26. The conclusion of these metric trends is similar to the conclusions for operating profit and net profit: HRS networks in the Expected and Delayed scenarios are not trending toward being self-sustaining by 2030 under the base case price assumptions. The Robust scenario does achieve positive gross margin in 2029 and maintains a stead DSCR above 2 after 2020. As mentioned earlier, improved economics in the Robust case are largely due to the greater economies of scale of larger stations, which are, in turn, justified based upon stronger market growth.

Figure 25: Summary of Gross Margin Results for the Central Hydrogen Price Projection in Each Scenario



Source: NREL

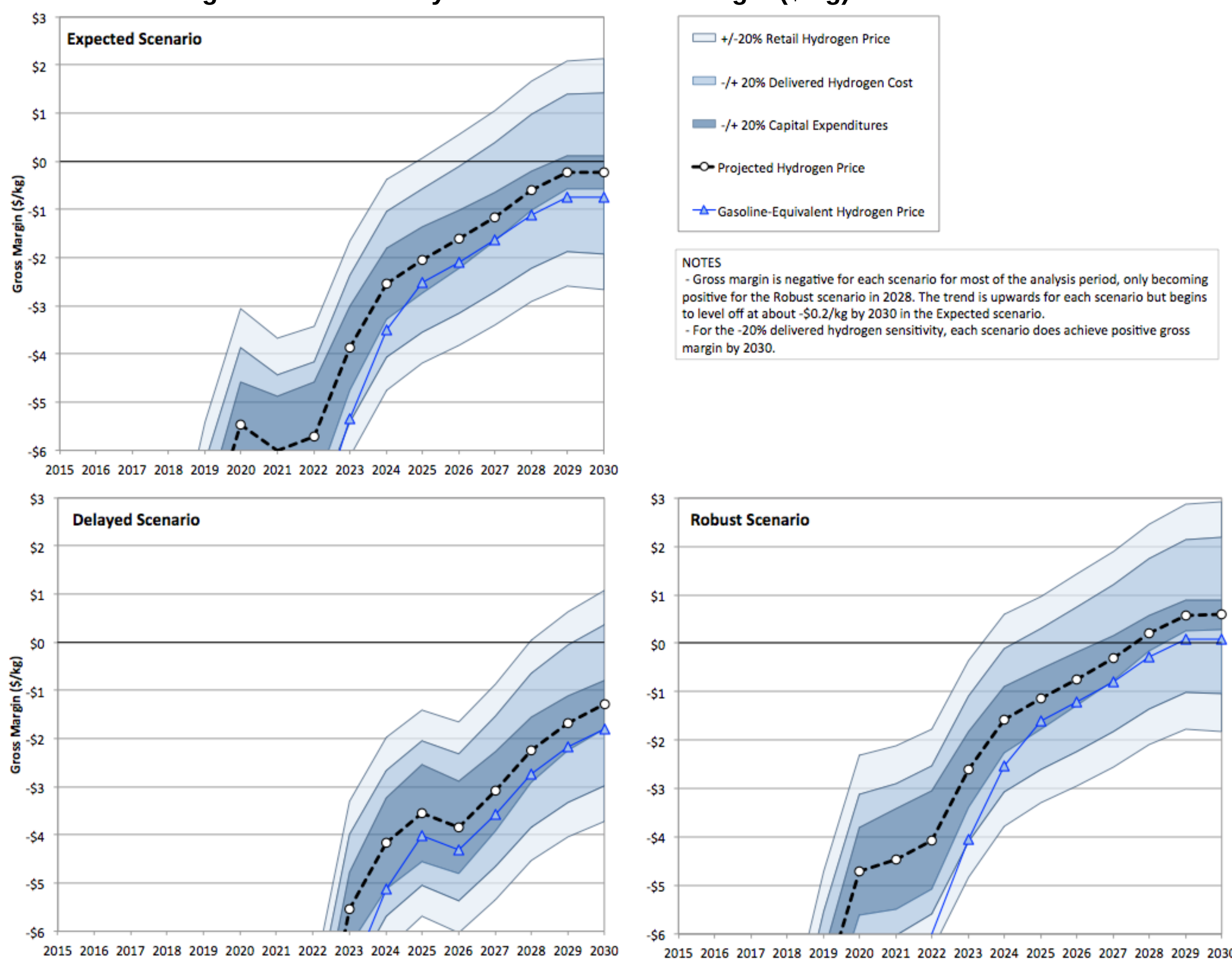
Figure 26: Summary of Debt-Service Coverage Ratio Results for the Central Hydrogen Price Projection in Each Scenario



Source: NREL

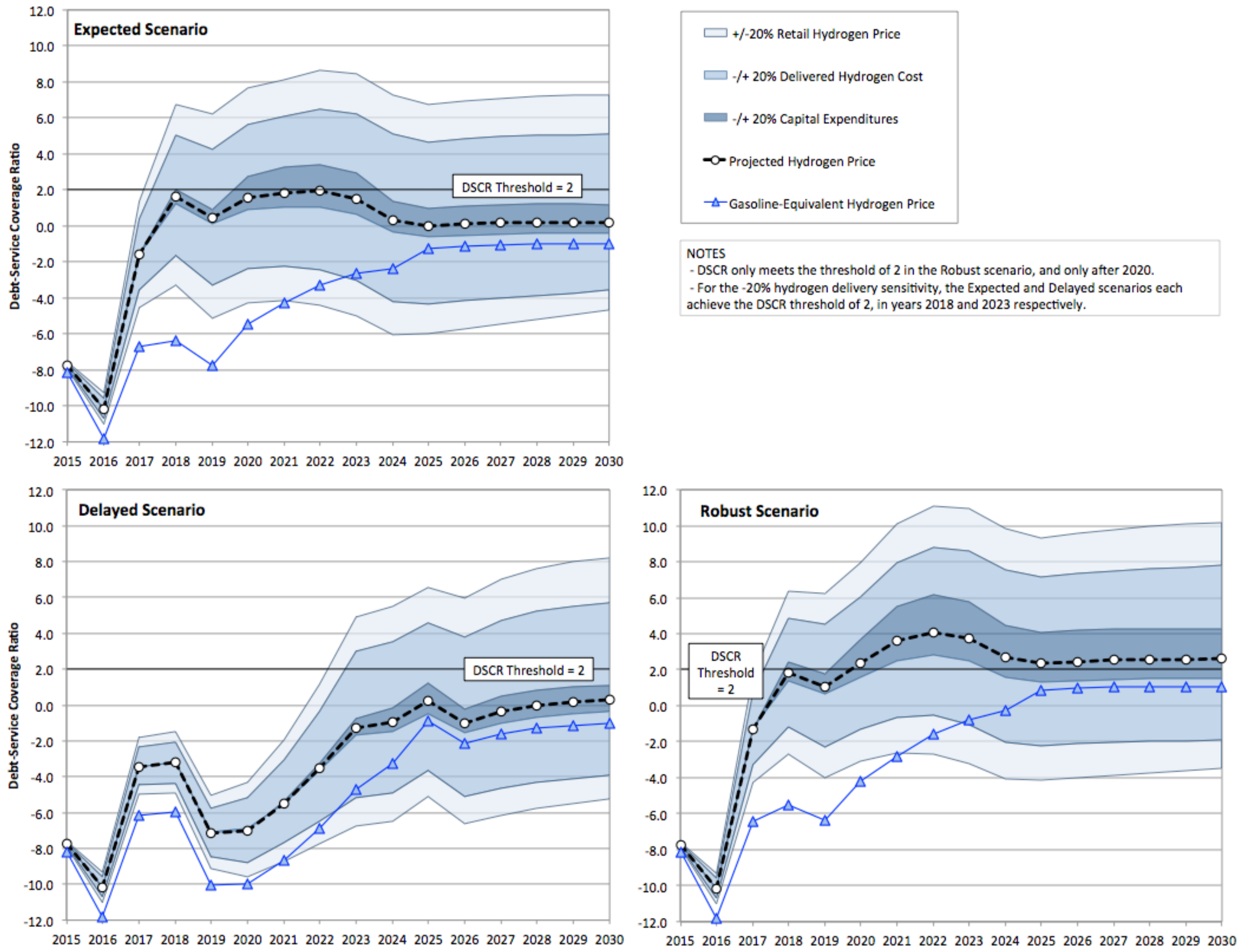
The sensitivities around gross margin and DSCR, shown in Figures 27 and 28, respectively, indicate potential for more positive trends. Again, an increase in revenue comparable to a reduction in the cost of hydrogen by 20 percent would be sufficient to achieve positive gross margin by 2030 and a DSCR above 2 by 2030 in each scenario. However, only the Robust scenario attains these thresholds unequivocally. The trends are more tenuous in the Expected and Delayed scenarios, with gross margin at less than $1.50 per kg in the last few years of the analysis period in the Expected scenario and only becoming positive in 2030 in the Delayed scenario.

Figure 27: Sensitivity Results for Gross Margin ($/kg) for All Scenarios



Source: NREL

Figure 28: Sensitivity Results for Debt-Service-Coverage Ratio (DSCR) for All Scenarios



Source: NREL

Financial Analysis of Nominal Stations within Group 2

The H2FAST model (Excel® version) was used to analyze the financial performance of several nominal HRS installed between 2016 and 2020, the period when Group 2 stations would be installed. The H2FAST model performs in-debt generally accepted accounting principles (GAAP) analysis, which produces annual financial performance articulation in terms of the following standard reporting statements:

Income statement accounts for total revenues received by stations, deducts operating expenses, evaluates taxes, and arrives at an annual net income.

Cash flow statement accounts for the cash position of a station based on operating cash flow, capital expenditures, and financing activities (equity, debt, and capital incentives).

Balance sheet tracks the assets, liabilities, and equity of each station.

This analysis framework is identical to the H2FAST calculations reported for the entire HRS network in the previous section. However, applying H2FAST to each station allows for reporting at a greater level of detail in terms of input assumptions and results. The analysis is performed in line with the specifications of different station types.

Three HRS types are examined, each closely resembling the stations modeled within the Group 2 network discussed in the previous section:

350 kg/day LH2: Delivered liquid hydrogen station.

180 kg/day GH2: Delivered gaseous hydrogen station.

100 kg/day electrolysis: On-site water electrolysis station.

Details on how the H2FAST model was modified and applied to generate the results presented below are discussed in Appendix C. The above reference station types were analyzed assuming a 2018 installation date. Similar to the assumptions in the HRS network scenarios in the previous section, each HRS is assumed to follow a six-year linear ramp-up of demand to a maximum of 75 percent utilization, achieved by Q3 of 2025. Stations are analyzed both with and without accounting for the influence of incentives.

When applied, the incentives follow the following structure:

- Capital incentives were assumed to cover 80 percent of the capital costs and capped at $2.125M per station.
- Operating incentives were calibrated to the Energy Commission allowance of $300,000 over the first three years of station operations.

The results for each station are indicated in scorecards below, which have the following sections:

- Station specifications table
- Financial benchmarks
- Plot of equity investor cumulative cash flow (after-tax, leveraged cash flow from and to investors)
- Real levelized cash flows throughout the project
- Financing contribution breakdown.

In the financial performance scorecards, equity investment is articulated as the sum of investments from an equity investor throughout the project. (In some scenarios equity investors would need to provide additional investment in the business to assure liquidity of the business in years of revenue shortfalls.)

Detailed financial report tables for each station type are provided in Volume 2 – Technical Appendices.

Case analysis: 350 kg/day Delivered Liquid Station Installed in 2018

Figure 29 indicates the scorecard for a 350 kg/day LH2 station installed in 2018 and receiving no incentives. The scorecard shows a negative NPV over the life of the station, equal to -$1.25

million. NPV is calculated based on the cash flow to and from equity investors and discounted at the rate of 10 percent. This result suggests that the station is not an attractive investment proposition. The break-even hydrogen sale price, which would yield an IRR of 10 percent, would be $13.53/kg, while the levelized sales revenue is only $9.91. (See Volume 2 – Technical Appendices for a discussion of levelized costs.) The gap in costs that needs to be closed to enable the project to be attractive to an investor is about $3.62/kg. This gap can be closed by increasing the total revenues or decreasing the total operating expenses. Without closing this gap, an investor would be losing on average $0.68 for each kilogram of hydrogen sold.

The same 350 LH2 station is shown with incentives in Figure 30. The profitability of this scenario is greatly improved, yielding a projected investor after-tax, leveraged IRR of 32 percent and a project NPV of $595,000. This means an investor would yield $595,000 by investing in this project compared to any other investment with an IRR of 10 percent. Due to the capital incentive, the cost basis for the equity investor has decreased to $360,000. This project would yield an average return to investors of $1.32 per kilogram.

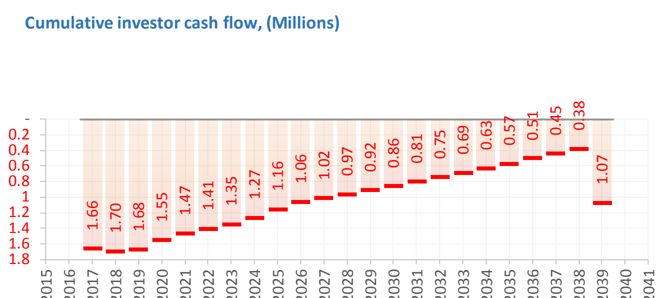
Figure 29: Financial Performance Scorecard for a 350 kg/day, Liquid Delivery Station without Incentives

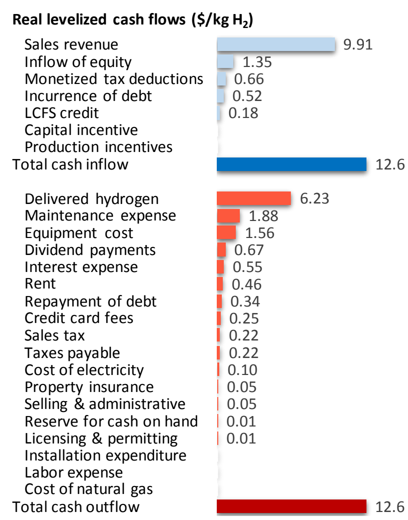
Station specification

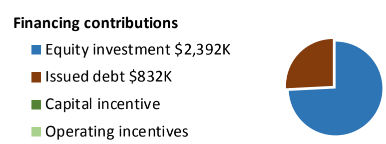
Station type		Delivered liquid
Station capacity (kg/day)		350
Vintage year		2018
SERA Scenario		Expected
Station cost (all-in)	$	2,497,000
Station capital incentives	$	-
O&M incentive (for 3 years)	$	-

Financial performance benchmark

IRR		N/A
Profitability index		0.4
NPV after-tax, nominal @ 10% discount	$	(1,250,000)
First year of positive EBITD		6
Real levelized retail margin ($/kg)	$	3.58
Price of H2 to yield 10% IRR ($/kg)	$	13.53







Source: NREL

NOTE: A feature of the above figure is that in 2039 the cumulative cash flow appears to decrease from -$0.39 million to -$1.05 million. This is due to financial closing of the project. The largest effect is due to repayment of outstanding revolving debt, and some value is recovered through recovery of cash on hand used in the business operation. For all stations, it is assumed that at the end of the project, any decommissioning costs would be covered by the salvage value of the station.

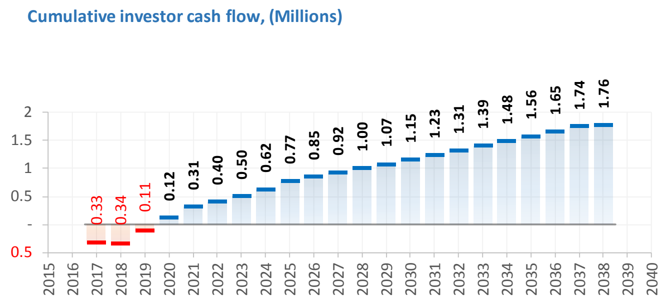
Figure 30: Financial Performance Scorecard for a 350 kg/day, Liquid Delivery Station with Capital and Operating Incentives

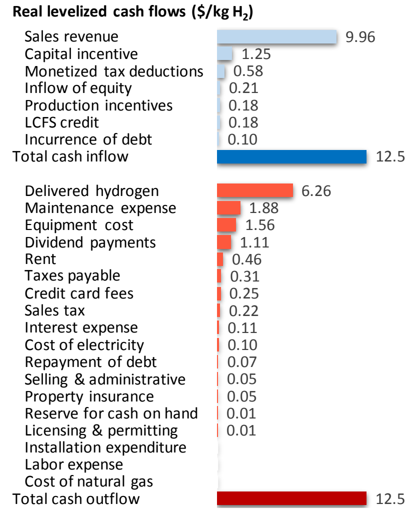
Station specification

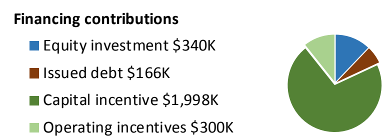
Station type		Delivered liquid
Station capacity (kg/day)		350
Vintage year		2018
SERA Scenario		Expected
Station cost (all-in)	$	2,497,000
Station capital incentives	$	1,998,000
O&M incentive (for 3 years)	$	100,000

Financial performance benchmark

IRR		37.3% √
Profitability index		5.3
NPV after-tax, nominal @ 10% discount	$	653,000
First year of positive EBITD		4
Real levelized retail margin ($/kg)	$	3.59
Price of H2 to yield 10% IRR ($/kg)	$	8.38







Source: NREL

While this performance appears very favorable, in actuality there are several financial risks that are not reflected in these results. These include, but are not limited to, the following:

- The cost of delivered hydrogen may not be realized.
- Demand for hydrogen is not assured.
- The price of gasoline may decrease over the life of the project. This decrease may place downward pressure on the price of hydrogen at retail stations as hydrogen retailers strive to compete with gasoline.
- While the project relies on a 20-year financial analysis period, this time frame may be reduced as a result of emerging technologies entering the market.
- Hydrogen sales may be reduced due to increased competition from other stations built later in later years and close to the station.

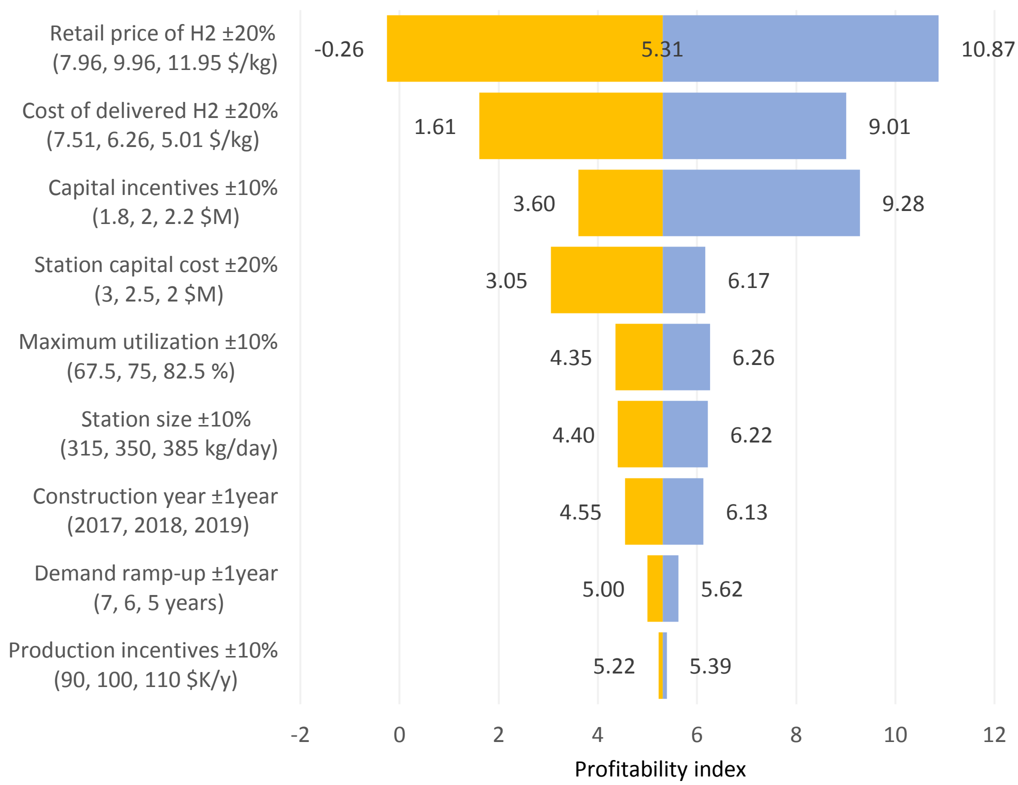
Each of these risks could affect the financial performance of a station. Thus, while the single-point analysis in Figure 30 shows an IRR of 32 percent, this return is not guaranteed, and in light of various uncertainties the station may yield lower returns for investors.

A sample of results based upon several uncertainty variables is presented in the tornado chart in Figure 31. This figure shows the effect of varying key projection parameters by ±20 percent, ±10 percent, or ±1 years. The financial parameter indicated by the bars is the profitability index (PI) of the project.

Cash flows for PI considerations are equity investor initial investment and subsequent net cash flows to and from the business. Generally speaking, a PI of 2.0 would be roughly equivalent to an IRR of 10 percent, and a PI of 6 would be roughly equivalent to IRR of 30 percent. Any values above 2.0 would tend to allow investors to offset risk factors.

As indicated, the retail price of hydrogen is the most important parameter affecting profitability, along with the closely related cost of delivered hydrogen (the difference between the two being the retail margin). An increased hydrogen price or decreased delivered cost of hydrogen, all else equal, would result in increased station profitability. Station capital cost is also an important variable for station profitability. This parameter would become less important than suggested in the figure if the ramp-up in station utilization were improved. A station that can reach high utilization sooner would be less sensitive to upfront capital expenditures and other fixed costs, such as maintenance. Capital incentives are a direct substitution for capital costs, and it can be seen that higher capital incentives provide increased profitability. Other parameters of consideration are also listed but have less pronounced effect on the profitability of hydrogen.

Figure 31: Effect on the Profitability Index (PI) from Key Analysis Parameters



Source: NREL

NOTE: Each sensitivity parameter was modulated by ±20 percent, ±10 percent, or by ±1 year. Categories on the Y-axis describe the parameter being varied and specify the values of the parameter in the same sequence as shown left-to-right in the figure. For example, the central value for PI, in this case 5.22, reflects the baseline or middle values for all parameters listed. The right-most value shown for each bar in the figure corresponds to PI attained when using the third parameter value listed under each parameter name (which all other parameters set at their central values).

Case analysis: 180 kg/day Gaseous Delivery Station Installed in 2018

Figure 32 shows the scorecard for a 180 kg/day GH2 station installed in 2018 without incentives. As might be expected from the results for the 350 kg/day station, this station also performs poorly. The same station's financial performance with incentives is shown in Figure 33, and the attractiveness of the investment is greatly improved with the application of incentives. The figure also indicates, however, that cumulative cash flow is decreasing after 2025. This is largely due to accelerated depreciation being depleted. This station should be examined as to whether it provides a positive marginal profit per kilogram sold after 2025 to ensure the operator has an incentive to keep operating. The effect on PI due to varying different parameters is shown in the tornado chart in Figure 34. The relative ranking of importance of each parameter is the same as for the 350 kg/day station. The most important factors for this station type are also the capital cost contribution and the retail margin (the difference between the cost of delivered hydrogen and dispensed retail price).

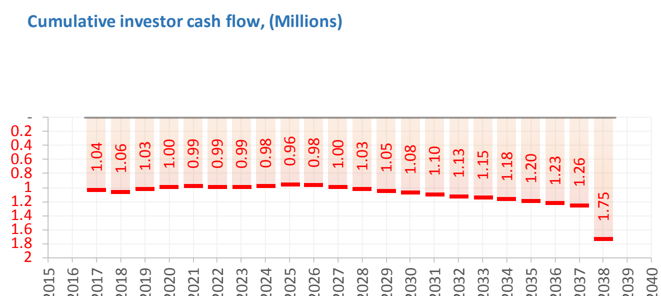
Figure 32: Financial Performance Scorecard for a 180 kg/day Gaseous Delivery Station without Incentives

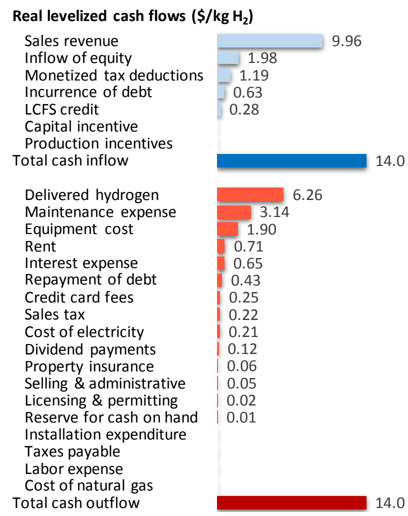
Station specification

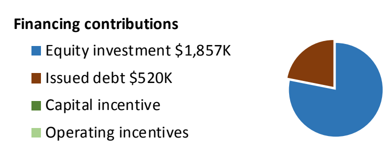
Station type		Delivered gas
Station capacity (kg/day)		180
Vintage year		2018
SERA Scenario		Expected
Station cost (all-in)	$	1,561,000
Station capital incentives	$	-
O&M incentive (for 3 years)	$	-

Financial performance benchmark

IRR		N/A
Profitability index		-0.5
NPV after-tax, nominal @ 10% discount	$	(1,133,000)
First year of positive EBITD		N/A
Real levelized retail margin ($/kg)	$	3.49
Price of H2 to yield 10% IRR ($/kg)	$	16.02







Source: NREL

Figure 33: Financial Performance Scorecard for a 180 kg/day Gaseous Delivery Station with Capital and Operating Incentives

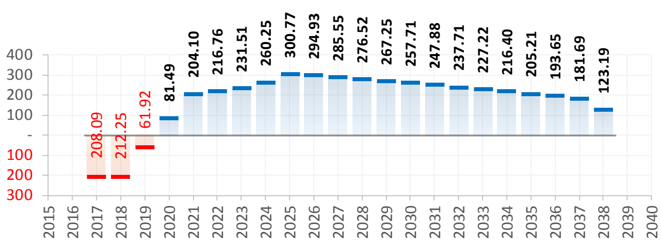
Station specification

Station type	Delivered gas	
Station capacity (kg/day)		180
Vintage year		2018
SERA Scenario		Expected
Station cost (all-in)	$	1,561,000
Station capital incentives	$	1,249,000
O&M incentive (for 3 years)	$	100,000

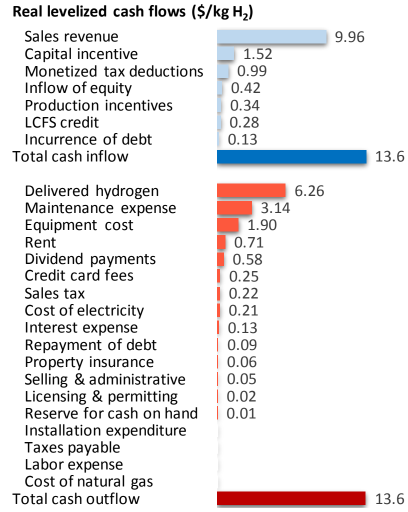
Financial performance benchmark

IRR		29.6% √
Profitability index		1.7
NPV after-tax, nominal @ 10% discount	$	116,000
First year of positive EBITD		4
Real levelized retail margin ($/kg)	$	3.49
Price of H2 to yield 10% IRR ($/kg)	$	9.52

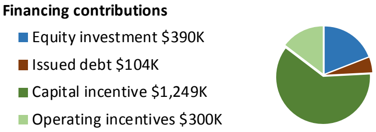
Cumulative investor cash flow, (Thousands)



Real levelized cash flows ($/kg H_2)

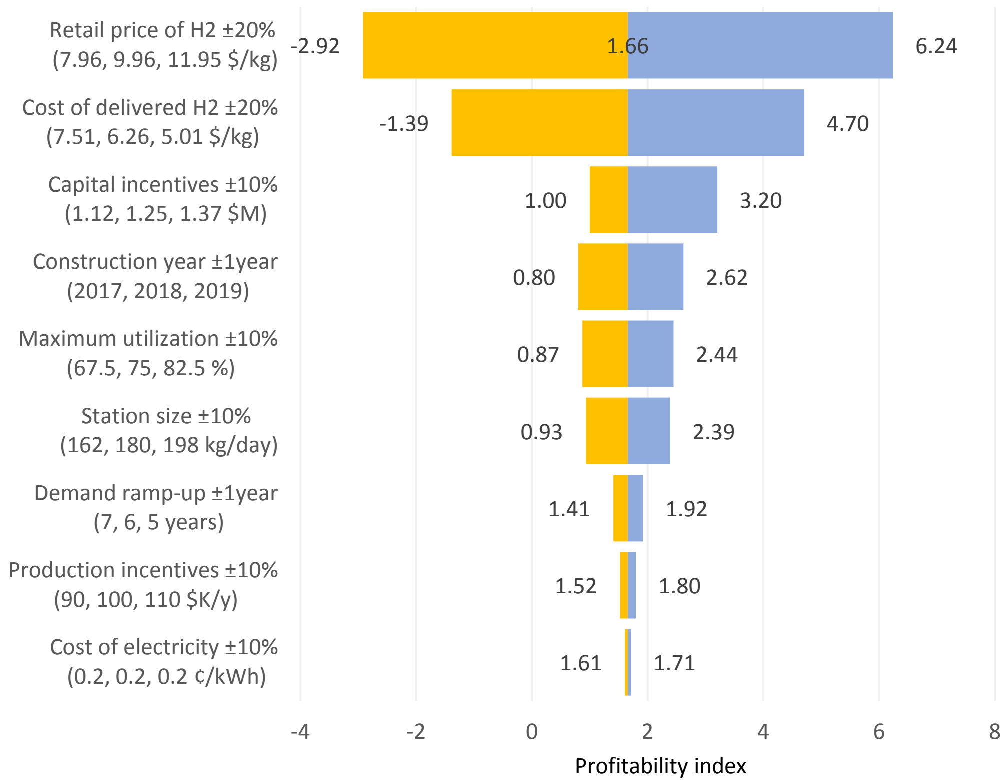


Financing contributions



Source: NREL

Figure 34: Effect on the Profitability Index (PI) from Varying Key Parameters



Source: NREL

Case analysis: 100 kg/day Electrolysis Station

Electrolysis stations have the most challenging financial performance. This station type incurs the highest capital cost per capacity as well as an expensive feedstock cost. The scorecard for a 100 kg/day electrolysis station is shown in Figure 35. Without incentives, this electrolysis station would not attract typical investors. While this analysis uses the same retail price of hydrogen as for all other stations, it is conceivable that consumer demand for 100 percent renewable hydrogen could exact a higher retail price. This factor is not considered in this study but could be included as market data are collected in the future. The same station is shown with incentives in Figure 36. Capital and operating incentives for electrolysis stations significantly improve the financial performance. However, station performance is still short of being attractive to the average investor, with a NPV of -$724,000 relative to a 10 percent discount rate.

Figure 35: Financial Performance Scorecard for a 100 kg/day Electrolysis Station without Incentives

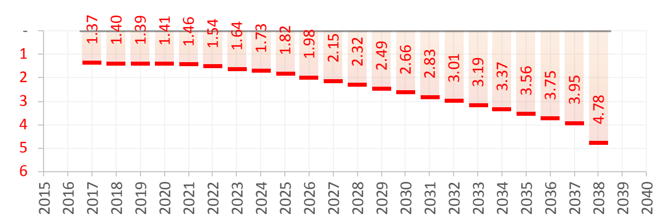
Station specification

Station type	Electrolysis	
Station capacity (kg/day)		100
Vintage year		2018
SERA Scenario		Expected
Station cost (all-in)	$	2,060,000
Station capital incentives	$	-
O&M incentive (for 3 years)	$	-

Financial performance benchmark

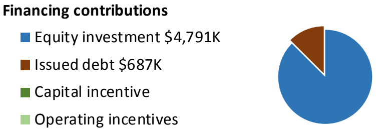
IRR		N/A
Profitability index		-1.9
NPV after-tax, nominal @ 10% discount	$	(2,300,000)
First year of positive EBITD		N/A
Real levelized retail margin ($/kg)	$	2.74
Price of H2 to yield 10% IRR ($/kg)	$	31.67

Cumulative investor cash flow, (Millions)



Real levelized cash flows ($/kg H_2)

Financing contributions



Source: NREL

Figure 36: Financial Performance Scorecard for a 100 kg/day Electrolysis Station with Capital and Operating Incentives

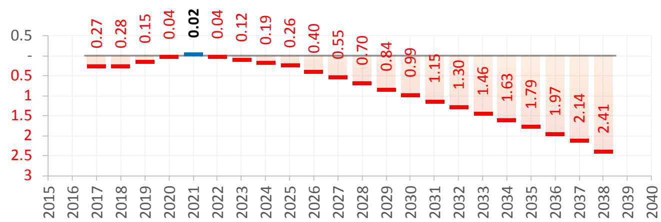
Station specification

Station type	Electrolysis	
Station capacity (kg/day)		100
Vintage year		2018
SERA Scenario		Expected
Station cost (all-in)	$	2,060,000
Station capital incentives	$	1,648,000
O&M incentive (for 3 years)	$	100,000

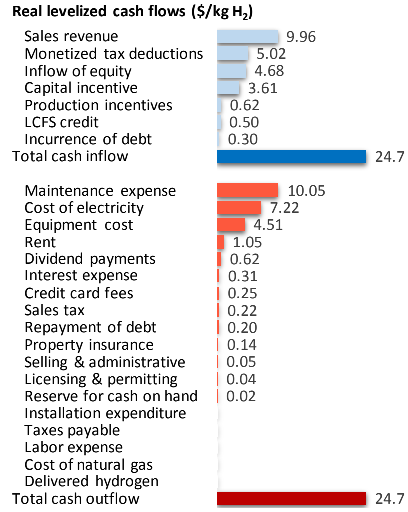
Financial performance benchmark

IRR		N/A
Profitability index		-5.7
NPV after-tax, nominal @ 10% discount	$	(724,000)
First year of positive EBITD		N/A
Real levelized retail margin ($/kg)	$	2.74
Price of H2 to yield 10% IRR ($/kg)	$	16.91

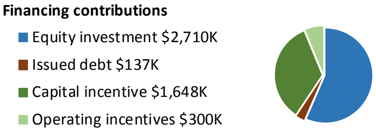
Cumulative investor cash flow, (Millions)



Real levelized cash flows ($/kg H_2)



Financing contributions

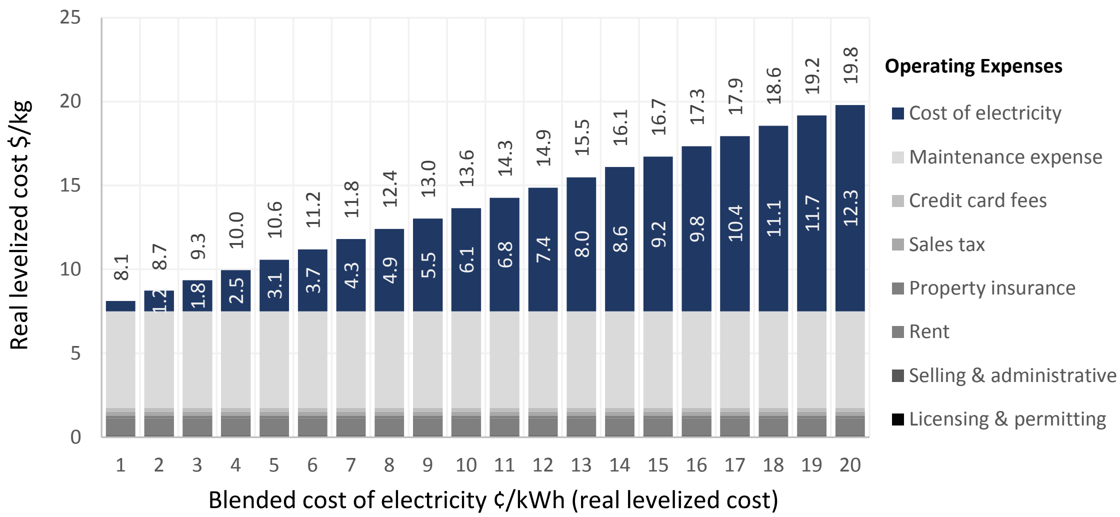


Source: NREL

While electrolysis stations may be challenging from an investment perspective, they may also provide value to the electricity grid and may be of interest to some investors due to that capability.[32]

The central case for electrolysis stations assumes industrial electricity price projections from the *Annual Energy Outlook 2015* applicable for California. However, those projections may not be indicative of particular end-user applications. Due to the unique capabilities of electrolysis units, these stations may be able to secure more favorable rate structures.[33] To examine the potential influence of different rate structures, Figure 37 indicates how the real levelized cost of hydrogen could change with different average blended prices for electricity. As shown, the variation can be dramatic, potentially ranging from $15/kg at an average electricity price of $0.05/kWh to $24/kg at an average electricity price of $0.20/kWh. The cost per kg associated with electricity is broken out in the dark blue bars.

Figure 37: Sensitivity of Total Operating Cost Relative to the Blended Cost of Electricity to an Electrolysis Station



Source: NREL

Financial Performance Projections for Stations Installed in 2025

In addition to the nominal stations installed within Group 2, analyzed in the previous section, it is informative to examine stations that might be installed within the Group 3+ stations around 2025, ten years from today. These stations would presumably benefit from reduced capital costs and lower investment risk due to a more robust hydrogen supply chain and reduced

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32 Melaina and Eichman (2015). *Hydrogen Energy Storage: Grid and Transportation Services.* NREL/TP-5400-62518. National Renewable Energy Laboratory. Available at: http://www.osti.gov/scitech/biblio/1170355.

33 Eichman, J, Kevin William Harrison, and Michael Peters. 2014. *Novel Electrolyzer Applications: Providing More Than Just Hydrogen*. National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy14osti/61758.pdf.

uncertainty in demand growth projections. To reflect these improved demand conditions, we assume the ramp up to 75 percent utilization to occur in three years rather than six years.

In this analysis, the financial performance of each station is evaluated with and without incentives. The station's financial is also evaluated with and without the amount of incentives required for each station to yield an IRR of 10 percent. Table 16 summarizes the financial performance of the stations. The 600 and 350 kg/day stations achieve an IRR greater than 10 percent without capital incentives. Given the capital cost reductions, economies of scale, and projected fixed O&M cost assumptions used in this report, these two stations appear to be self-sustaining beyond 2025. The 600 kg/day station achieves an IRR of 17 percent and a PI of 4.0, while the 350 kg/day station achieves a 14 percent IRR and a PI of 3.0. See table 16.

The 600 kg/day station does not require capital incentives to achieve an IRR greater than 10 percent. This station appears to have sufficient economies of scale to be self-sustaining beyond 2025. Complete score cards are shown for the 350 kg/day and 600 kg/day stations in the subsequent figures.

Without incentives, the 180 kg/day station achieves an IRR of 9.1 percent and requires an additional $40,000 in capital incentives to achieve a 10 percent IRR and a PI of 2.2. The 100 kg/day station exhibits limited economies of scale, a PI of minus .032 without incentives, and an IRR of 10 percent. The 100 kg/day station would have a PI 1.07 if $0.8 million in capital incentives are provided. For electrolysis to be financially successful in 2025, the base station assumptions would have to vary from the base station assumptions in this report (i.e., stronger business case, larger capacity, greater economies of scale, lower electricity rates, enhanced grid services, or reduced fixed O&M costs).

Table 16: Financial Performance for 2025 Stations without Incentives and with Capital Incentive Sufficient to Achieve a 10 Percent IRR

	600 kg/day Delivered Liquid	350 kg/day Delivered Liquid	180 kg/day Delivered Gas		100 kg/day Electrolysis	
Capital incentive ($M)	$0.00	$0.00	$0.00	$0.04	$0.00	$0.80
Profitability index	3.97	3.03	1.99	2.16	-0.32	1.07
IRR	16.8%	13.6%	9.1%	10.0%	N/A	10.0%

Source: NREL

The scorecards for 180 kg/day, 350 kg/day, and 600 kg/day stations are shown in subsequent figures. In general, these longer term station cost projections are more speculative than the Group 2 station projections given that technology innovations are difficult to predict. Various innovations could occur by 2025 that change the market advantage of delivery methods and station designs. Variations in vehicle designs and consumer preferences may change the demand requirements assumed for 2025 stations; station network development could require different types of stations. These variations may or may not be needed as supply chains expand geographically to serve new urban and regional markets.

Figure 38: Financial Performance Scorecard for a 180 kg/day Delivered Gaseous Station without Capital and Operating Incentives

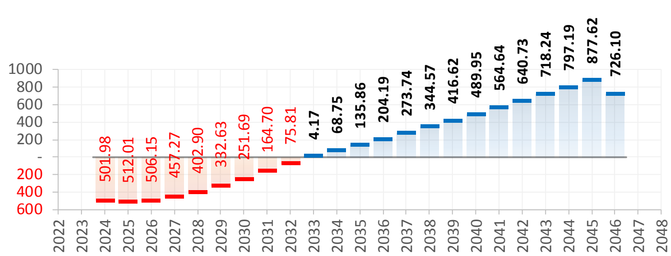
Station specification

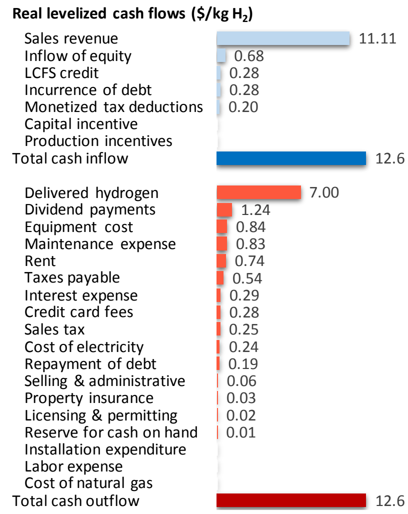
Station type	Delivered gas	
Station capacity (kg/day)		180
Vintage year		2025
SERA Scenario		Expected
Station cost (all-in)	$	753,000
Station capital incentives	$	-
O&M incentive (for 3 years)	$	-

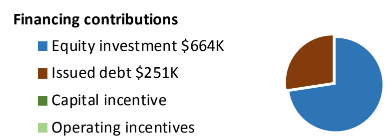
Financial performance benchmark

IRR		9.1%
Profitability index		2.0
NPV after-tax, nominal @ 10% discount	$	(36,000)
First year of positive EBITD		4
Real levelized retail margin ($/kg)	$	3.87
Price of H2 to yield 10% IRR ($/kg)	$	11.28

Cumulative investor cash flow, (Thousands)







Source: NREL

Figure 39: Financial Performance Scorecard for a 180 kg/day Delivered Gaseous Station with Capital Incentives Sufficient to Yield IRR of 10 Percent

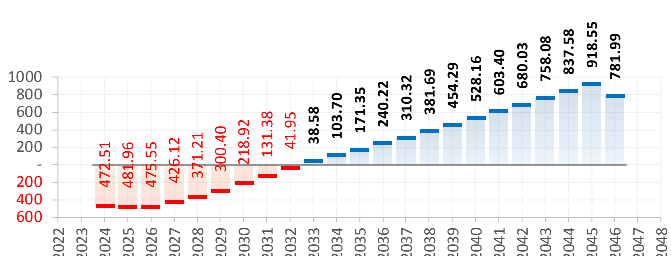
Station specification

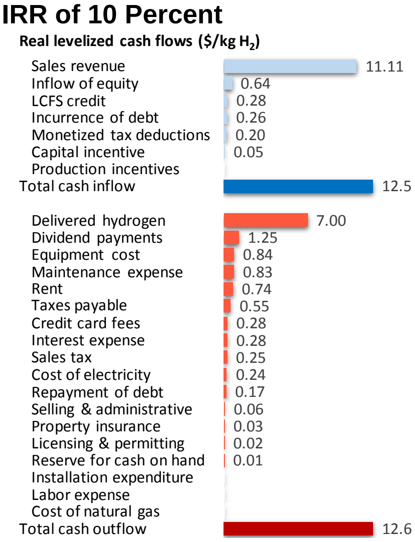
Station type	Delivered gas	
Station capacity (kg/day)		180
Vintage year		2025
SERA Scenario		Expected
Station cost (all-in)	$	753,000
Station capital incentives	$	44,000
O&M incentive (for 3 years)	$	-

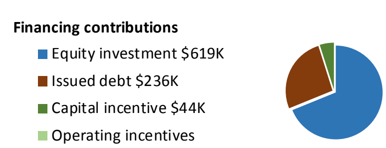
Financial performance benchmark

IRR		10.0% √
Profitability index		2.2
NPV after-tax, nominal @ 10% discount	$	-
First year of positive EBITD		4
Real levelized retail margin ($/kg)	$	3.87
Price of H2 to yield 10% IRR ($/kg)	$	11.11

Cumulative investor cash flow, (Thousands)







Source: NREL

Figure 40: Financial Performance Scorecard for a 350 kg/day Delivered Liquid Station without Capital and Operating Incentives

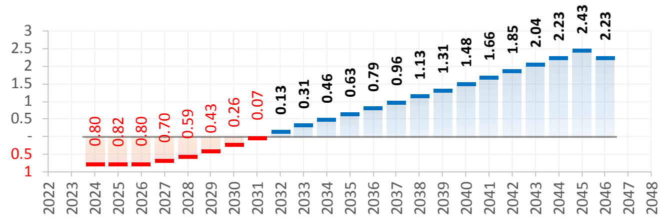
Station specification

Station type	Delivered liquid	
Station capacity (kg/day)		350
Vintage year		2025
SERA Scenario		Expected
Station cost (all-in)	$	1,205,000
Station capital incentives	$	-
O&M incentive (for 3 years)	$	-

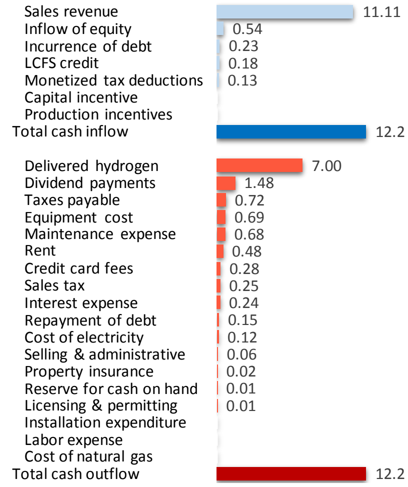
Financial performance benchmark

IRR		13.6%	√
Profitability index		3.0	
NPV after-tax, nominal @ 10% discount	$	285,000	
First year of positive EBITD		3	√
Real levelized retail margin ($/kg)	$	3.99	
Price of H2 to yield 10% IRR ($/kg)	$	10.42	

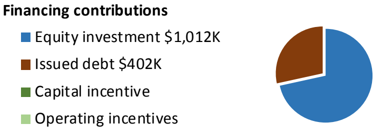
Cumulative investor cash flow, (Millions)



Real levelized cash flows ($/kg H_2)



Financing contributions



Source: NREL

Figure 41: Financial Performance Scorecard for a 600 kg/day Delivered Liquid Station without Capital and Operating Incentives

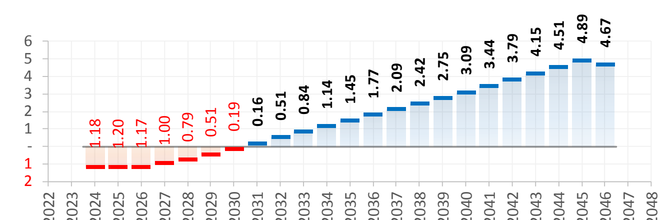
Station specification

Station type	Delivered liquid	
Station capacity (kg/day)		600
Vintage year		2025
SERA Scenario		Expected
Station cost (all-in)	$	1,764,000
Station capital incentives	$	-
O&M incentive (for 3 years)	$	-

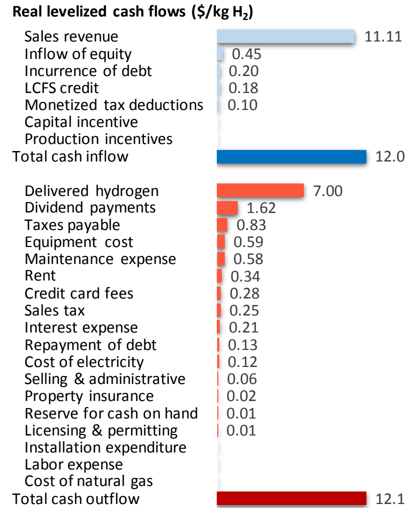
Financial performance benchmark

IRR		16.8%	√
Profitability index		4.0	
NPV after-tax, nominal @ 10% discount	$	864,000	
First year of positive EBITD		3	√
Real levelized retail margin ($/kg)	$	3.99	
Price of H2 to yield 10% IRR ($/kg)	$	9.90	

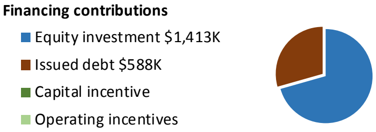
Cumulative investor cash flow, (Millions)



Real levelized cash flows ($/kg H_2)



Financing contributions



Source: NREL

CHAPTER 7: Conclusions

The following is a summary of the key findings to this first joint report:

- In 2016, more than 50 hydrogen stations will be open with capacity for more than 10,000 FCEVs. Future demand could outpace capacity by 2020-2021, demonstrating that continued State financial support for HRS is critical to enabling steady market growth for FCEVs in California.
- Given the current pace of station rollout and expected vehicle demand, an initial network of 100 stations is expected to be complete by 2020 and is anticipated to require roughly $160 million in public incentive funding.
- Significant improvements have been made in station development timelines.
- Hydrogen station costs are expected to begin declining around 2020 and could decrease by 50 percent in 2025 due to increased worldwide demand for HRS.
- Future hydrogen fuel process could drop to make the costs of operating a hydrogen vehicle more competitive.
- Continued public investment is required in the near term until business cases exists for nonsubsidized station development.

The State of California has allocated substantial public investments to develop a hydrogen refueling network in early market clusters, connectors and destinations to support commercial sales of FCEVs in California. The year 2015 has been critical for HRS development as numerous stations funded between 2009 and 2013 are finalized and begin retail operations. Commercial sale of FCEVs has begun with Hyundai and Toyota in 2015, while Honda has announced they will begin commercial sales in 2016.

More than 50 HRS are expected to be open in Northern and Southern California in 2016 and FCEV sales are projected to reach more than 1,000 vehicles. Although these numbers are small compared to the total number of gasoline stations and vehicles in California, they are large enough to stimulate introduction of a radically new, zero-emission vehicle technology. Early market sales of hybrid and battery electric passenger vehicles also began with small numbers of early adopters but increased quickly as consumers came to understand and appreciate the benefits of electric-drive technologies. This initial network of HRS will support more than 10,000 FCEVs.

The State of California will need to continue investing AB 8 funds to reach the 100-station milestone. Both capital and operations and maintenance incentives will be needed, although it is expected that the currently high incentive levels can decrease over time. Ongoing private sector investments from the auto industry will be important, and new sources of private capital will be vital. Ongoing Clean Vehicle Rebate Project funding incentives through ARB will also be important in stimulating early market sales of FCEVs. The more quickly that hydrogen fuel sales increase in California, the more likely it becomes that private capital will be invested in this emerging market. Until hydrogen sales increase with larger numbers of FCEVs on the road, the NREL financial analyses indicate that incentive funding through AB 8 enables positive revenues and profitability for HRS developers, which, in turn, sends important market signals for private investment opportunities in the hydrogen fueling network.

Results from this analysis indicate that under the best early market conditions with ongoing automaker investments in refueling infrastructure, potentially new investments from other private investors, and strong consumer response to FCEVs, 100 HRS with a network capacity of 26,000 kg/day could be developed in California by 2020. This scenario would require a cumulative total of $157 million in AB 118 and AB 8 funding.

However, if consumer response to FCEVs is slow and HRS developers do not continue station development in a timely manner, and if private sector investments in HRS diminish rather than increase, the Energy Commission would need to continue the current levels of incentive funding through 2023 to reach 100 stations. This scenario would require a cumulative total of $170 million in AB 118 and AB 8 funding, and the long term viability of the hydrogen fueling market in California would be less certain.

As required by AB 8, the Energy Commission and ARB will need to closely monitor the pace of FCEV deployment and HRS development to ensure that there is sufficient fueling capacity and coverage to serve a growing FCEV market. The 2018-2019 period will be critical in understanding if the Expected Scenario projections are realized, or if there is some type of market slowdown as illustrated in the Delayed Scenario. Should FCEVs come to California as anticipated, the Energy Commission, ARB, and FCEV stakeholders will need to work together to ensure there are solutions to avoid any delay or shortage of network fueling in the 2020-2021 time period.

As hydrogen fuel demand grows to support FCEV sales in the 30,000 to 80,000 vehicle range, AB 8 funding will need to be increasingly supplemented by private investment to keep pace with a rapidly growing market. The Energy Commission and ARB interpret the “market transformation” direction in AB 8 to mean that the current policy goal is to establish a strong initial network that can grow over time with larger amounts of private market support and lower levels of government incentive funding. Based on the expected FCEV market growth, the current analysis shows that as AB 8 expires in 2023, the hydrogen fuel market should be in good financial condition to attract the high levels of private capital that will be needed to ensure a steady transition to a self-sustaining hydrogen and FCEV market.

If data and analysis suggest that the Energy Commission should continue to allocate $20 million per year for HRS development, total HRS investments will likely exceed $200 million through 2023. A 100-station hydrogen fueling network will be an important achievement as the State of California pursues its carbon reduction goals and zero-emission vehicle deployment goals. However, these investments should be considered as the initial funding needed to create the potential for a self-sustaining FCEV market in California, rather than as completion or achievement of the long-term policy goal to add substantial levels of FCEVs to the mix of technologies needed to attain 1.5 million zero-emission vehicles by 2025.

APPENDIX A: Permitting Timeline Analysis

Permitting processes vary across different cities and counties; however, the processes generally involve two sequential phases: planning approval and issuance of the building permit (approval to build). Planning approval typically involves a station developer submitting a project plan with detailed site drawings to a local planning agency for approval. A planning agency then checks zoning regulations and determines what type of zoning permit is needed to ensure that the proposed project is allowed in the proposed location. The building permit process typically occurs after planning approval is obtained. This process may also require electric, mechanical, and/or plumbing permits. These planning and permitting agencies are also known as *authorities having jurisdiction* (AHJ).

California Environmental Quality Act (CEQA) determinations are generally made as part of permitting processes. To date, nearly all HRS have been found to be categorically exempt from CEQA because they are being developed at existing gasoline stations. Commonly used exemptions are: California Code of Regulations, Title 14, Section 15301 – existing facilities, Section 15303 – small structures, and/or Section 15304 – minor alterations to land. The Energy Commission files a notice of exemption for each station that is funded by the agency. AHJs are responsible for making their own determinations as part of their permitting processes.

The following sections assess permitting time for the three Energy Commission solicitations. The time durations were calculated as follows:

- Planning approval durations were calculated using planning document submission dates and planning approval dates.
- Approval to build durations were calculated using building permit application submission dates and approval to build dates.
- Total permitting durations were calculated using planning document submission dates (or building permit application submission dates if planning approval was not needed) and approval-to-build dates.

PON-09-608

Of the 11 stations originally funded through PON-09-608, 7 have received approvals to build, 1 is in the planning application process, 1has been canceled, and 2 have not yet submitted planning applications due to lack of a confirmed project site. The average number of days spent in the permitting process for the seven active stations that received approvals to build was 255 days.

Six of the seven stations that have received approvals to build in this group did not need separate planning approval, or the planning approval was incorporated into the building permit

(Diamond Bar, West Sacramento, L.A. – Santa Monica Blvd., Irvine – Jamboree, and L.A. – Beverly Blvd.) Only one station needed the sequential two-step process (San Juan Capistrano). State-level agencies participated in many of the meetings with local permitting agencies.

Of the remaining two projects, one has found a new site and is negotiating a commercial lease agreement, while the other continues to seek a new site.

PON-12-606

For the seven stations funded under PON-12-606, the average number of days spent in permitting process has been 391 days.

Only two of these seven stations (Woodland Hills and Chino) have obtained approval to build, which took 337 days in average. This is more than stations funded under PON-09-608 which took 206 days. For the Woodland Hills project, the planning approval was part of the final building permit.

To date, only the Anaheim and Chino projects have gone through the planning approval process, and the average number of days for these two stations to obtain approval was 128 days. This is roughly half of the amount of time it took for the PON-09-608 station, San Juan Capistrano station.

The projects in Mountain View, Foster City, and Los Altos in the Silicon Valley area have begun the planning approval process, although the Los Altos project may require a new site.

The State, represented by GO-Biz and Energy Commission staff, has participated in meetings with AHJs for roughly 70 percent of the stations. State-level participation was not needed for the other projects.

PON-13-607

For the 28 HRS funded under PON-13-607, the average number of days spent in the permitting process has been 196 days. For these stations, the State has participated in meetings with AHJs for about 76 percent of the stations.

To date, 19 stations have received planning approval, and 18 stations have received approvals to build. The average time required for planning approval has been 131 days, while the average time required for approval to build has been 81days. This is a marked improvement compared with PON-09-608 and PON-12-606.

The HRS projects in Ontario and Riverside did not need planning approval[34], while two additional stations are awaiting planning approval. Five projects from this solicitation are seeking new sites and have not begun the permitting process.

34 For the Ontario station, the station developer used International Standards Organization (ISO) containers to house most of the HRS equipment, which negated the need for planning approval. In the case of Riverside, the site is located on City property.

Permitting Trend Summary

Overall, the permitting process for the stations that were funded under PON-13-607 took less time on average compared with the stations that were funded under PON-09-608.

Compared to the stations funded under PON-09-608, the stations funded under PON-13-607 have shorter time in obtaining permits, a little more than two months shorter on average for the total time spent in permitting. Table A-1 shows the average permitting time and the maximum and minimum times for the three major funding solicitations.

Table A-1: Average, Maximum, and Minimum Permitting Times for California HRS

Solicitation No.	Average Permitting Time (days)	Minimum Permitting Time (days)	Maximum Permitting Time (days)
PON-09-608	255	139	402
PON-12-606	391	295	487
PON-13-607	196	61	280

Source: California Energy Commission

Permitting Trend per Station Developer

Permitting timelines are also analyzed by station developer. Table A-2 summarizes average permitting times for nine station developers. Some station developers only have one or two stations that have gone through permitting. First Element shows a low average permitting duration, especially considering the large number of stations that they are submitting to the permitting process.

Table A-2: Permitting Trend Analysis by Station Developer

HRS Developer	Planning Approval Duration (Average Days)	Approval to Build Duration (Average Days)	Total Permitting Duration (Average Days)	Total No. of Stations	No. of Stations with Permits
Air Liquide	111	Not Complete	Not Complete	2	1 for Planning
APCI	Not Complete	261	261	10	6 for Building
First Element	135	82	212	19	16 for Planning 15 for Building
H2 Frontier	144	379	487	1	1
HTEC	85	63	170	1	1
HyGen	87	Not Complete	Not Complete	3	1
ITM Power	NA	61	61	1	1
Linde Group	253	85	256	7	2 for Planning 2 for Building
Stratos Fuels	NA	101	101	1	1

Source: California Energy Commission

Factors for Improved Permitting Timelines

There are several factors contributing to the shorter permitting times needed for stations funded under PON-13-607 compared with PON-09-608.

A major factor has been the introduction of the Energy Commission's incentive funding strategy in the 2013 solicitation, which provides higher capital grant award levels and Operations and Maintenance (O&M) funding award levels for stations that can accelerate permitting and station development to an 18-month period (548 days).

A second major factor has been the substantial increase in state-level involvement with regional and local planning forums, including permitting seminars, safety seminars, site visits, and presentations at planning commission hearings and city council meetings. The State participated in most planning commission hearings. Since 2013, GO-Biz, Energy Commission and ARB representatives, have been reaching out to AHJs by conducting workshops, one-on-one meetings, ongoing email/phone communications, and so forth to help interpret fire codes, facilitate communications among stakeholders, and convey the state's position/support of developing hydrogen refueling stations.

Another possible reason is that First Element, which is developing more than half of the stations that are funded under PON-13-607 (19 out of 29 stations), hired a former city planner as a project team member. Having a staff member who is familiar with how local jurisdictions work in processing permit applications may have helped FirstElement avoid taking unnecessary steps, such as having to redesign a station late in the process. Also, FirstElement had pre-application meetings with AHJs for most stations. AHJs generally encourage pre-application meetings to help identify potential project design change needs, that is, the feasibility of the project site.

GO-Biz and Energy Commission representatives have been meeting with AHJs to discuss the State's commitment (*ZEV Action Plan*, Governor's Executive Order B-16-2012) and importance of developing hydrogen refueling stations, which often leads to the AHJs' commitment to making permitting stations high priority in their permit processing. GO-Biz and the Energy Commission representatives have also been attending Planning Commission hearings and City Council meetings to support the projects by articulating the state's *ZEV Action Plan*.

The National Fire Protection Association (NFPA) 2 requires greater setback distances for liquid hydrogen than for gaseous; therefore, hydrogen refueling stations using liquid hydrogen generally require a larger lot.[35] This has not interfered with permitting because station developers are typically aware of the lot size requirement before they select sites, so these greater distance requirements have not posed any issues for developing stations. However, there are a relatively small number of retail gasoline station sites in urban areas that are large enough to accommodate liquid HRS. The U.S. Department of Energy is working with the NFPA to review and perhaps reassess the setback requirements for liquid hydrogen stations.

35 National Fire Protection Association (NFPA). Quincy, Massachusetts. *NFPA 2: Hydrogen Technologies Code: 2011*, NFPA 2: 2011.

APPENDIX B: Station Costs

Stn #	Name	County	Capacity (kg/day)	Total Capital ($1000s)	Incentive ($1000s)		Station Type
					Capital	Operating	
1	Coalinga- W Dorris	Fresno	180	$2,055	$1,451		GH2 Truck
2	San Ramon- Bishop	Contra Costa	350	$2,783	$2,125		GH2 Truck
3	Burbank- W Verdguo	Los Angeles	100	$1,800	$940	$0.300	SMR
4	Irvine - Jamboree	Orange	30	$2,451	$1,960		GH2 Truck
5	Torrance- W 190th	Los Angeles	60	$3,095	$2,476		Pipeline
6	Newport Beach- Jamboree	Orange	100	$1,037	$829		GH2 Truck
7	Harbor City- S. Western	Los Angeles	60	$2,500	$0	$0.300	Electrolysis
8	Los Angeles- State University	Los Angeles	60	$984	$0	$0.300	Electrolysis
9	Diamond Bar- E Copley	Los Angeles	180	$2,933	$1,467	$0.300	Electrolysis
10	Los Angeles- Aviation	Los Angeles	100	$3,288	$2,630		SMR
11	Los Angeles- Santa Monica	Los Angeles	180	$2,496	$1,997		GH2 Truck
12	Chino- East End	San Bernardino	100	$4,558	$3,000		Electrolysis
13	Los Angeles- Beverly	Los Angeles	180	$8,364	$6,691		GH2 Truck
14	Los Angeles- Cloverfield	Los Angeles	180	$984	$2,046		GH2 Truck
15	Redondo Beach- Beryl	Los Angeles	180	$2,521	$2,017		GH2 Truck
16	South Pasadena- Fair Oaks	Los Angeles	180	$2,055	$1,451		GH2 Truck
17	Woodland Hills- Topanga Canyon	Los Angeles	180	$3,358	$2,686		GH2 Truck
18	Anaheim- E La Palma	Orange	100	$2,434	$1,500		GH2 Truck
19	Costa Mesa- Harbor	Orange	180	$2,055	$1,451		GH2 Truck
20	Irvine- Walnut	Orange	180	$2,543	$2,034		GH2 Truck
21	La Cañada-Flintridge- Foothill	Los Angeles	180	$2,055	$1,451		GH2 Truck
22	Lawndale- Inglewood	Los Angeles	180	$2,497	$1,998		GH2 Truck
23	Los Angeles- Lincoln	Los Angeles	180	$2,055	$1,451		GH2 Truck
24	Los Angeles- Hollywood	Los Angeles	180	$2,055	$1,451		GH2 Truck
25	Ontario- Holt	San Bernardino	100	$3,459	$3,097		Electrolysis
26	Orange- East Chapman	Orange	130	$3,255	$1,769		Electrolysis
27	Pacific Palisades-Pac. Coast Hwy	Los Angeles	130	$3,255	$1,769		Electrolysis
28	Long Beach- Long Beach	Los Angeles	180	$2,055	$1,451		GH2 Truck
29	Lake Forest- Lake Forest	Orange	180	$2,531	$1,451	$0.300	GH2 Truck
30	San Juan Cap.- Junipero Sera	Orange	350	$2,732	$2,732		LH2 Truck
31	Laguna Niguel- Crown Valley	Orange	180	$2,055	$1,451		GH2 Truck
32	Mission Viejo- Marguerite	Orange	180	$2,687	$1,500		GH2 Truck
33	Riverside- Lincoln	Riverside	100	$3,587	$2,125		Electrolysis
34	West Sacramento- South River	Yolo	350	$2,495	$2,495	$0.300	LH2 Truck
35	San Diego- Carmel Valley	San Diego	180	$2,055	$1,451		GH2 Truck
36	Mill Valley- Redwood	Marin	180	$2,055	$1,451		GH2 Truck
37	South San Francisco- S Airport	San Mateo	180	$2,055	$1,451		GH2 Truck
38	Hayward- West A	Alameda	180	$2,055	$1,451		GH2 Truck
39	Palo Alto- El Camino Real	Santa Clara	180	$3,209	$2,125		GH2 Truck
40	Woodside- Skyline	San Mateo	140	$3,253	$2,125		Electrolysis
41	Foster City- Foster City	San Mateo	350	$2,505	$1,500		LH2 Truck
42	Oakland- Langley	Alameda	350	$2,566	$2,125		LH2 Truck
43	Redwood City- Veterans	San Mateo	180	$2,055	$1,451		GH2 Truck
44	Campbell- Winchester	Santa Clara	180	$2,055	$1,451		GH2 Truck
45	Saratoga- Saratoga	Santa Clara	180	$2,055	$1,451		GH2 Truck

Stn #	Name	County	Capacity (kg/day)	Total Capital ($1000s)	Incentive ($1000s)		Station Type
					Capital	Operating	
46	San Jose- North First	Santa Clara	180	$2,055	$1,451		GH2 Truck
47	Los Altos- Homestead	Santa Clara	350	$2,532	$1,500		LH2 Truck
48	Mountain View- Leong	Santa Clara	350	$2,532	$1,500		LH2 Truck
49	Santa Barbara- S La Cumbre	Santa Barbara	180	$2,055	$1,451		GH2 Truck
50	Rohnert Park- Redwood	Sonoma	130	$3,255	$1,769		Electrolysis
51	Truckee- Donner Pass	Nevada	180	$2,055	$1,451		GH2 Truck

Source: California Energy Commission

APPENDIX C: Technical Description of Cost Reduction Method

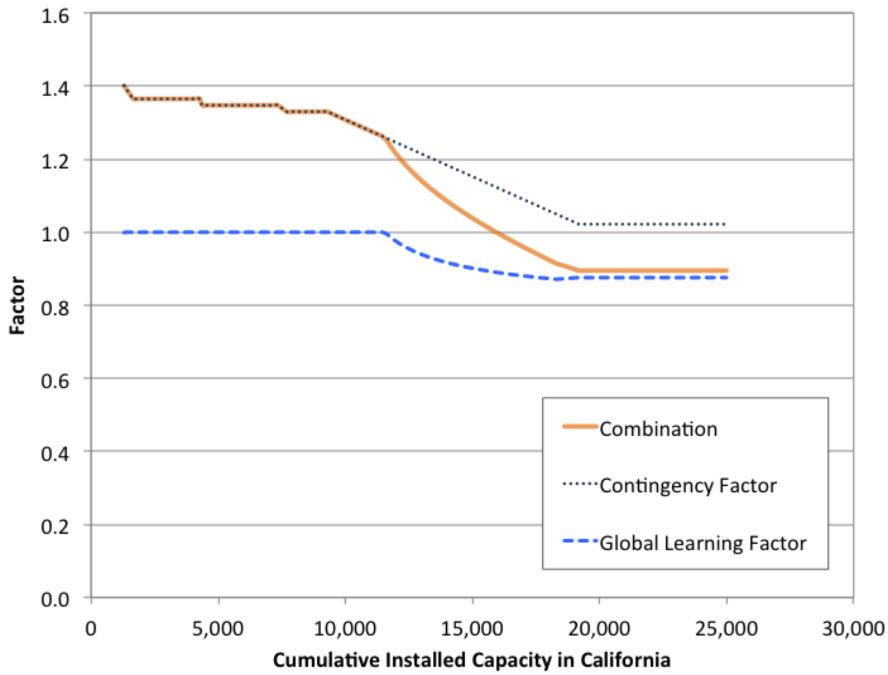
For this report, NREL modified survey-based cost estimates from a 2013 industry survey to more closely match expected near-term station costs and anticipated global HRS installations.[36] The Hydrogen Station Cost Calculator (HSCC) equation from the NREL study estimates cost reductions due to both economies of scale for larger station sizes and lessons as a function of total installed global capacity. This equation is modified with a contingency factor to account for escalated costs associated with the very near-term, first generation of commercial HRS. As more experience is gained installing HRS in California, it is assumed that this contingency factor will decline. This factor is shown as a function of cumulative installed capacity in California in Figure C-1, starting at 33 percent to 40 percent for funded stations and declining linearly after cumulative installations exceed 10,000 kg/day capacity. A 2 percent contingency factor persists after 20,000 kg/day in cumulative capacity. Based upon reported station development plans in Europe, Japan, and South Korea, it is assumed that about 225 HRS are developed globally with a total capacity of about 40,000 kg/day. Assuming those stations are built between 2016 and 2018, the effect on capital costs from lessons learned is indicated by the dashed blue line in Figure C-1. The combination of the two factors is shown as a solid orange line. The result is a 12 percent decline in capital costs at about 18,000 kg/day of capacity in California.

Fixed operating and maintenance (O&M) costs are also difficult to project into the future, given the lack of empirical data. While improved data are anticipated in future years, the current analysis relies upon the fixed O&M costs suggested from the HSCC report. While these O&M costs are considered conservative and probably reflect high costs associated with the deployment of new technologies and installation processes, they are assumed to persist over the life of the HRS simulated in the present report (See Chapter 6). Equations for total fixed O&M, as well as two subcomponents, rent and maintenance and repairs, are shown in Figure C-2. As indicated by the total O&M trend, for the small stations considered in the present report with installed capacities between 100-350 kg/day, O&M costs range from $400 to $1,200 per year for each kg/day of capacity. Using the equation indicated, this translated to an O&M cost of about $157,000 per year for a 180 kg/day station, or $173,000 per year for a 350 kg/day station. This cost translates to about 7.5 percent of the capital cost of a station, and is significantly higher than long-term estimates of O&M for a mature system (closer to 2-3 percent in the DOE cost model estimates). Acknowledging this, the present analysis assumes that these

36 Melaina and Penev. 2013. "Hydrogen Station Cost Estimates: Comparing Hydrogen Station Cost Calculator Results with other Recent Estimates" National Renewable Energy Laboratory, Report Number NREL/TP-5400-56412. http://www.nrel.gov/docs/fy13osti/56412.pdf.

initially high O&M costs decline over time to 5 percent of capital costs (in the year a station is built) over the 2015 to 2025 time frame.

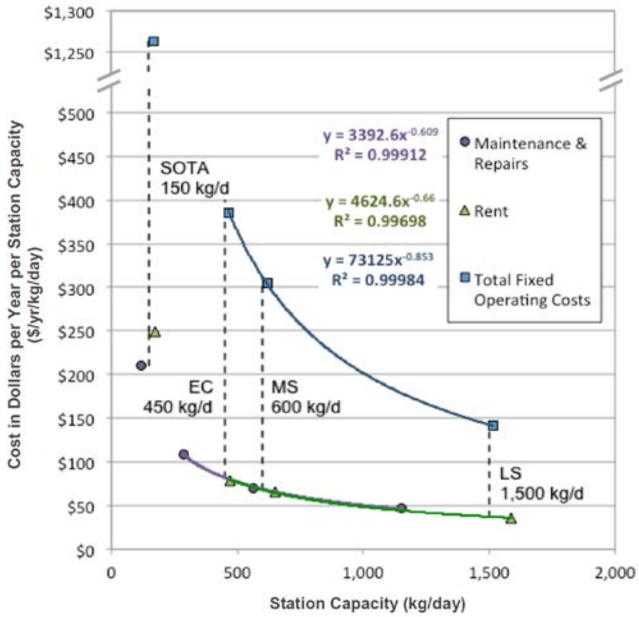
Figure C-1: Contingency and Global Learning Factors for Capital Costs



Source: NREL

While these estimates are acknowledged as conservative, they are based upon industry responses from the HSCC study, and are considered an acceptable substitute for the empirical data that will be collected over the next several years from stations installed in California. As discussed in Chapter 6, sensitivities around these or other base cost assumptions can have a significant influence on the financial performance of stations.

Figure C-2: Fixed Operating Costs from the Hydrogen Station Cost Calculator Study



Source: NREL

APPENDIX D: SERA Model Scenario Development

HRS Network Development for Each Scenario

The scenarios are developed through the following steps:

1. Articulate HRS network development over time for each of the three viable scenarios. Building upon empirical data for Group 1 stations (first 51 stations), project the expected costs, incentives, and operational characteristics of the subsequent 49 Group 2 stations for each scenario.
2. Assess the financial performance of the Groups 1 and 2 HRS network, as well as nominal stations within Group 2. Focus on financial metrics of interested to relevant stakeholders, including funding agencies (for example, Energy Commission), retail station owners and investors, and banks.
3. Relying upon financial assessment metrics developed in step 2, characterize the degree to which future ARFVTP funding at $20 million per year through 2023 may or may not be sufficient to establish a HRS network in California.

The sections below examine each of the three steps in turn.

In each of the three scenarios, more HRS are provided state capital and O&M incentives and earlier in time than in the Baseline development rate of seven stations per year through 2023, with the funding gap filled by private investment. As discussed, this scenario design component is intended to explore variations in how state funds may be allocated to best leverage public dollars while complying with the disbursement requirements of AB8. These scenario variations are intended to reflect a broad range of possible outcomes as the Energy Commission adapts to market signals and network development trends. Analytically, fiscal year funds are allocated from 2016 onward according to the following:

- All new stations receive capital incentives equal to either 80 percent of total capital or $2.125 million, whichever is greater, and if sufficient funds are available.
- New stations receive $100,000 per year in O&M incentives for a period of three years, if funds are available.
- AB 8 funds are available from the past and current year, plus one future year.

In this report, it is assumed that during the early market introduction of FCEVs, a reasonable assumption for maximum average utilization across the network 75 percent of nameplate capacity. While total demand for hydrogen exceeds the supply and total capacity of the Groups 1 and 2 stations, it is assumed that these first 100 HRS provide FCEV drivers with a similar level of convenience as conventional gasoline stations, with peak demand levels being reached on weekends and during the summer. Given normal fluctuations in hourly, daily, and seasonal demand, utilization rates at a particular HRS may exceed 75 percent. However, during this rapid market growth phase with new small stations being deployed to expand market territories and new large stations being deployed within established markets (inevitably drawing demand away from existing nearby stations during the first few years of operation), an average of 75 percent across the network is considered relatively optimistic. Higher average network utilization rates would likely indicate some FCEV owners queuing to buy fuel and waiting longer than is typical during peak times at conventional gasoline stations.

This variability between scenarios in total demand and HRS network development schedules, especially for Groups 1 and 2 stations, allows for an exploration in how different trends might evolve over time, and how allocation of ARFVTP funds might influence financial performance. The importance of Groups 1 and 2 stations achieving positive financial performance metrics is emphasized by the trends in Energy Commission funds allocated over time compared to capital funds required from other sources (such as from private equity or banks), as indicated in Figure 18. Energy Commission capital incentives are indicated by dark orange bars, with the balance of other capital funds required indicated as stacked light blue bars. O&M incentives allocated per year are indicated by the gray lines with circles, and total incentives per year are indicated by the black dashed line. This figure indicates funds according to the year in which the receiving stations are installed, rather than the year in which the funds are disbursed.

These trends are separated into those allocated to Groups 1 and 2 stations, indicated by darker stacked bars, and those allocated to stations in Groups 3+, indicated by faint stacked bars for capital and the grey lines with smaller circles for O&M incentives. The separation also occurs by year, with funds for Group 3+ stations shown for 2021 and later years in the Expected and Robust scenarios, and for 2022 and later years in the Delayed scenario. Due to overcapacity established by 2020 in the Delayed scenario (see Figure 18), new funds are not allocated until new stations are required in 2024 and 2025, receiving AB8 funds available at the end of the program period. The dashed line indicating total funds tends to hover just above $20 million per year, compensating for 2017 as a year with no funds being allocated after the large allocations in 2015 and 2016.

Table D-1 shows the precise incentive allocations over the three scenarios that are depicted in Figure 18.

Table D-1: Summary of Network Capacities, Station Numbers, and Costs by Scenario

Scenario and Attribute	Groups 1 & 2						
Expected	**2010-14**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Number of new stations	8	36	7	8	12	15	14
Number of existing stations	0	8	44	51	59	71	86
Total stations	8	44	51	59	71	86	100
New Capacity (kg/day)	930	6,230	2,090	1,640	2,260	2,720	2,473
Existing Capacity (kg/day)	0	930	7,160	9,250	10,890	13,150	15,870
Total Capacity (kg/day)	930	7,160	9,250	10,890	13,150	15,870	18,343
New Capital Incentives ($M)	$5.3	$54.5	$10.8	$13.4	$18.2	$16.5	$12.0
O&M incentives ($M)	$2.3	$7.5	$2.0	$2.4	$3.6	$4.5	$4.2
Total Incentives ($M)	$7.6	$62.0	$12.8	$15.8	$21.8	$21.0	$16.2
Other Capital ($M)	$9.0	$24.3	$5.4	$3.6	$6.9	$13.0	$13.05
Delayed	**2010-14**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Number of new stations	8	36	7	0	2	3	5
Number of existing stations	0	8	44	51	51	53	56
Total stations	8	44	51	51	53	56	61
New Capacity (kg/day)	930	6,230	2,090	190	200	540	910
Existing Capacity (kg/day)	0	930	7,160	9,250	9,440	9,640	10,180
Total Capacity (kg/day)	930	7,160	9,250	9,440	9,640	10,180	11,090
New Capital Incentives ($M)	$5.3	$54.5	$10.8	$0.0	$3.7	$4.1	$8.1
O&M incentives ($M)	$2.3	$7.5	$2.0	$0.0	$0.6	$0.9	$1.5
Total Incentives ($M)	$7.6	$62.0	$12.8	$0.0	$4.3	$5.0	$9.6
Other Capital ($M)	$9.0	$28.2	$8.3	$0.5	$0.9	$1.0	$2.0
Robust	**2010-14**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Number of new stations	8	36	7	8	12	15	14
Number of existing stations	0	8	44	51	59	71	86
Total stations	8	44	51	59	71	86	100
New Capacity (kg/day)	930	6,230	2,090	2,650	3,690	4,570	4,114
Existing Capacity (kg/day)	0	930	7,160	9,250	11,900	15,590	20,160
Total Capacity (kg/day)	930	7,160	9,250	11,900	15,590	20,160	24,274
New Capital Incentives ($M)	$5.3	$54.5	$10.8	$15.6	$16.0	$16.5	$12.0
O&M incentives ($M)	$2.3	$7.5	$2.0	$2.4	$3.6	$4.5	$4.2
Total Incentives ($M)	$7.6	$62.0	$12.8	$18.0	$19.6	$21.0	$16.2
Other Capital ($M)	$9.0	$24.3	$5.4	$5.8	$14.7	$19.8	$19.7

Source: NREL

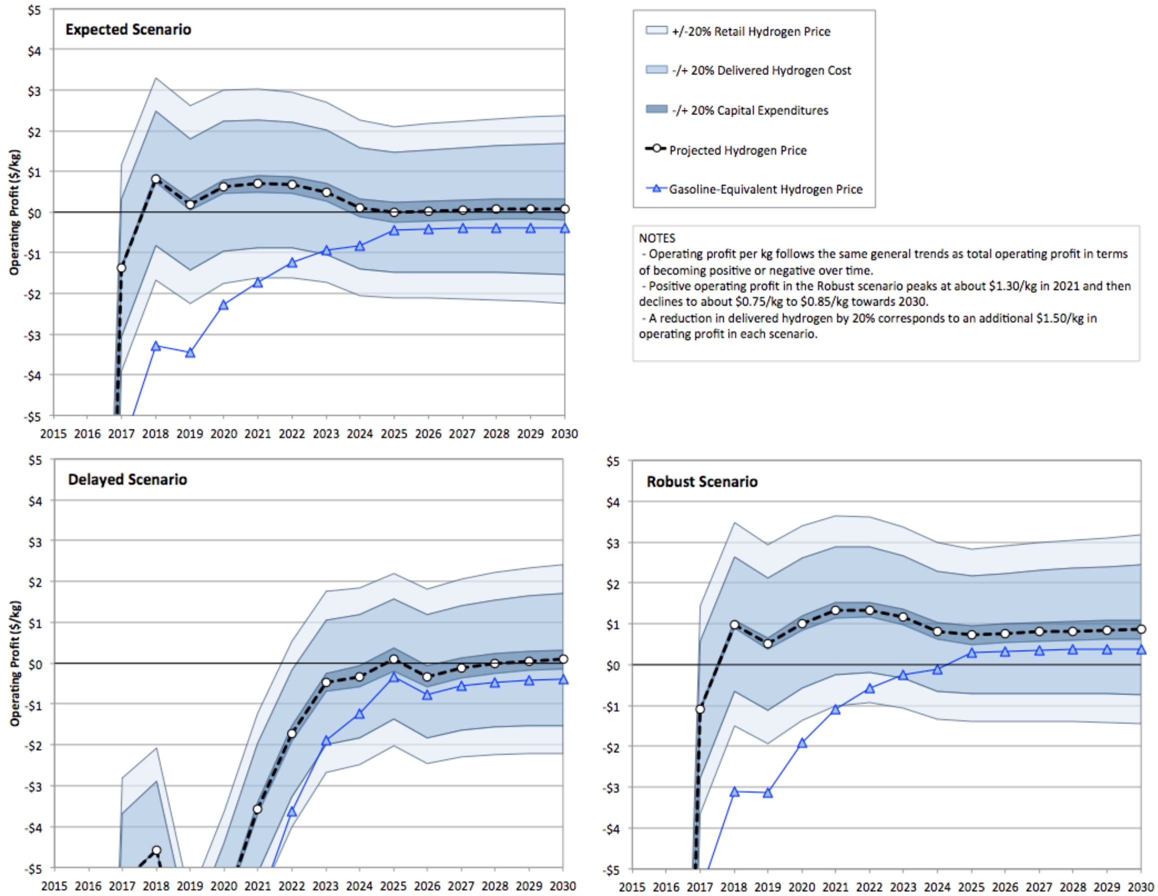
Table D-1 continued: Summary of Network Capacities, Station Numbers, and Costs by Scenario

Scenario and Attribute	Groups 3+						Summations by Group		
Expected	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Groups 1&2**	**Groups 3+**	**All**
Number of new stations	6	62	38	81	210	316	100	713	813
Number of existing stations	100	106	168	206	287	497			
Total stations	106	168	206	287	497	813			
New Capacity (kg/day)	1,237	16,641	10,199	21,740	56,364	84,814	18,343	190,996	209,339
Existing Capacity (kg/day)	18,343	19,580	36,221	46,420	68,160	124,524			
Total Capacity (kg/day)	19,580	36,221	46,420	68,160	124,524	209,339			
New Capital Incentives ($M)	$6.00	$20.0	$20.0	$20.0	$0.0	$0.0	$130.6	$66.0	$196.6
O&M incentives ($M)	$1.80	$0.0	$0.0	$0.0	$0.0	$0.0	$26.50	$1.80	$28.30
Total Incentives ($M)	$7.8	$20.0	$20.0	$20.0	$0.0	$0.0	$157.1	$67.8	$224.9
Other Capital ($M)	$6.5	$112.1	$60.5	$152.5	$445.2	$653.4	$75.2	$1,430	$1,505
Delayed	**2021**	**2022**	**2023**	**2024**	**2024**	**2025**	**Groups 1&2**	**Groups 3+**	**All**
Number of new stations	8	9	11	11	2	7	100	9	109
Number of existing stations	61	69	78	89	100	100			
Total stations	69	78	89	100	102	107			
New Capacity (kg/day)	1,180	1,640	2,160	1,625	295	1,590	17,695	1,885	19,580
Existing Capacity (kg/day)	11,090	12,270	13,910	16,070	17,695	17,990			
Total Capacity (kg/day)	12,270	13,910	16,070	17,695	17,990	19,580			
New Capital Incentives ($M)	$9.2	$14.7	$16.7	$17.1	$31.12	$21.25	$144.1	$52.4	$196.5
O&M incentives ($M)	$2.1	$2.7	$3.2	$3.5	$2.10	$2.70	$26.3	$4.8	$31.1
Total Incentives ($M)	$11.3	$17.4	$19.9	$20.6	$33.2	$23.9	$170.4	$57.2	$227.6
Other Capital ($M)	$3.2	$3.7	$4.2	$16.1	$29.31	$20.01	$76.9	$49.3	$126.2
Robust	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Groups 1&2**	**Groups 3+**	**All**
Number of new stations	6	71	91	166	386	919	100	1,639	1,739
Number of existing stations	100	106	177	268	434	820			
Total stations	106	177	268	434	820	1739			
New Capacity (kg/day)	2,036	19,056	24,424	44,554	103,602	246,660	24,274	440,333	464,607
Existing Capacity (kg/day)	24,274	26,310	45,366	69,791	114,345	217,948			
Total Capacity (kg/day)	26,310	45,366	69,791	114,345	217,948	464,607			
New Capital Incentives ($M)	$5.96	$20.00	$20.00	$20.00	$0.00	$0.00	$130.7	$66.0	$196.6
O&M incentives ($M)	$1.80	$0.00	$0.00	$0.00	$0.00	$0.00	$26.5	$0.00	$28.3
Total Incentives ($M)	$7.8	$20.0	$20.0	$20.0	$0.0	$0.0	$157.2	$67.8	$224.9
Other Capital ($M)	$8.46	$129.6	$170.4	$324.8	$788.5	$1,812.6	$98.8	$3,234.4	$3,333

Source: NREL

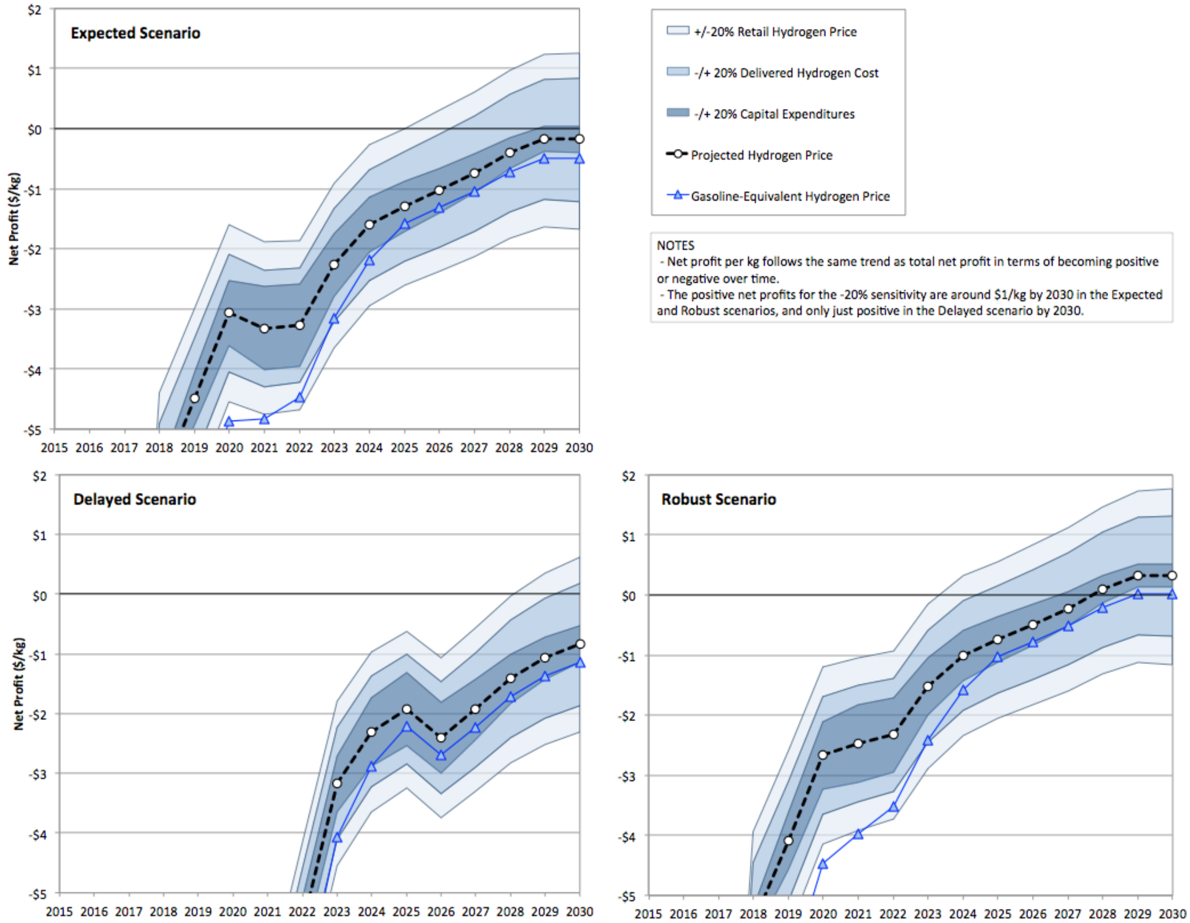
APPENDIX E:
Additional Sensitivity Runs with H2FAST

Figure E-1: Sensitivity Results for Operating Profit ($/kg) for All Scenarios



Source: NREL

Figure E-2: Sensitivity Results for Net Profit ($/kg) for All Scenarios



Source: NREL