Expansion of Stark Area Regional Transportation Authority Hydrogen Refueling Capabilities

A Feasibility Study

Prepared for: Stark Area Regional Transit Authority

In Support of the Renewable Hydrogen Fuel Cell Collaborative

Prepared by: CALSTART, Inc.

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CALSTART

SARTA

RENEWABLE HYDROGEN FUEL CELL COLLABORATIVE

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E. EXECUTIVE SUMMARY

This study investigated options for expanding the capacity of the existing hydrogen refueling station at SARTA to accommodate additional transit vehicles as well as future passenger vehicles. To this end, an objective was to determine the requirements to handle up to 12 40-foot transit buses, five paratransit vehicles and an indeterminate number of FCEV automobiles. The goal is to be able to simultaneously fill four vehicles with 350 bar fuel tanks and to have an additional capability for filling 700 bar fuel tanks. This would involve installing two additional 350 bar dispenser nozzles and a separate dispenser with 700 bar storage and associated compressors and chiller.

Total demand for hydrogen under the baseline configuration without the FCEV automobiles is estimated at 480 kg/day. However, providing for some redundancy in the system, and in anticipation of future expansion, most of the case studies considered focused on peak capacity closer to 1,000 kg/day.

This study considered means to add a renewable component to the refueling station as well as the introduction of on-site hydrogen production. The necessary equipment for processing and dispensing the hydrogen was explored, as well as various options for storing the additional compressed hydrogen needed. Finally, the study examined various options for financing the overall project.

E.1 RENEWABLE OPTIONS

There are two renewable opportunities for the SARTA station. These are renewable electricity and renewable natural gas. A third, hybrid option combines the two. Renewable electricity options considered included local solar photovoltaic electricity and wind power contracts. Solar photovoltaic was also considered at both the utility scale (multi MW) and industrial scale (100s of kW). Both were found feasible for SARTA, although the utility scale installation would only make sense if there were a major opportunity to sell electricity into the grid during daytime, *and* if electrolysis were selected as the on-site hydrogen production technology.

Wind power contracts appear to be the most economical approach to renewable energy at SARTA. However, wind power would not be local. There exist utility scale wind farms in the western part of Ohio, but neighboring states and places as far away as Texas could be simpler. Contracts were found to be reported at less than $20/MWh ($0.02/kWh).

Renewable natural gas could be produced locally from either digester gas from a local water reclamation facility or a local landfill. The installation of a sludge digester at the water reclamation facility appears to be economically infeasible. However, a local landfill was located that already has wells and a landfill gas upgrading system that is injecting gas into the local grid operated by Dominion East Ohio. Although that gas is already under contract, there are opportunities to purchase gas from other remote landfills until the local landfill either increases their output or the existing contracts expire. However, renewable natural gas is expensive with current contracts reported at $15/dekatherm.

The third, hybrid option would involve contracting for renewable natural gas and then using some or all of that gas to generate electricity on site using either rich burn natural gas engines, or small gas turbines. The pros and cons of this approach are explored in detail under a separate study associated with this project.

E.2 ON-SITE HYDROGEN GENERATION

Three approaches to on-site hydrogen generation were explored in detail. The first is called Tri-Generation Molten Carbonate Fuel Cell, or Tri-Gen MCFC. The others are PEM electrolysis and steam methane reforming (SMR).

Tri-Gen MCFC is in simplest terms a molten carbonate fuel cell that is operated in a way that excess hydrogen produced in the fuel cell is recovered rather than burned for process heat. A modest amount of medium-grade heat is also recovered and available for local physical plant operations such as HVAC. Total electricity production is 2.35 MW, and hydrogen production is 1,270 kg/day.

Tri-Gen MCFC has the largest footprint by far, at 20,000 sq. ft., of any of the options considered. It is also the most expensive at an estimated $25 - $30 million total installed cost. However, the vendor reports that the cost of the produced hydrogen is in fact quite competitive, and depending on the value of the produced electricity, it could be in the range of $5 - $10/kg. It is clear that this does not include amortization of the equipment over its seven-year expected life, as that would add about $10/kg to the cost using straight line depreciation.

PEM electrolysis is a much lower capital cost option for producing hydrogen. It also has a smaller footprint, with one vendor estimating 1,000 sq. ft., excluding storage and dispensing. The cost for a system including storage and two dual-nozzle 350 bar dispensers was estimated at roughly $6 million, depending on the vendor. An additional dispenser for 700 bar refueling was estimated at $450 k. The cost of hydrogen generated via PEM electrolysis is generally high, and highly dependent on electricity cost. A general rule of thumb is to assume 65 – 70 kWh/kg for hydrogen produced via PEM electrolysis.

On-site steam methane reforming is generally considered cost competitive with delivered liquid hydrogen, especially as equipment costs have come down. It also has a smaller footprint than the other options explored. A typical integrated skid mounted unit measures about 10 x 46 ft and is about 13 ft tall, excluding compression and storage. Another feature of SMR is that two of the vendors contacted said they prefer to own and operate the units and sell the gas to SARTA. Capital costs for SMR systems at the 1,000 kg/day scale were not made available by vendors.

E.3 GAS HANDLING

Some of the on-site hydrogen generation suppliers contacted were interested in supplying only a part of the system – often only the hydrogen production equipment. This leaves a need to provide compression, storage, chilling and dispensing. For this the project team contacted PowerTech Labs in Surrey, BC. While they might be ineligible under FTA Buy America, PowerTech was willing to provide a fairly detailed system description, complete with cost estimates for materials and labor.

The proposal includes 180 kg of 875 bar storage, 700 kg 450 bar storage, 485 kg/day compression capacity, refrigeration, two dual nozzle 350 bar dispensers, and a single nozzle 700 bar dispenser. Total cost, installed, was estimated at $4 million. Options for additional compressor capacity and additional refrigeration load came in at an additional $400 k.

E.4 HYDROGEN STORAGE

Based on experience with the California Hydrogen Highway initiative, station owners/operators have repeatedly recommended having storage equivalent to 2 – 3 times planned daily consumption. For SARTA's plans, consumption is anticipated to be 480 kg/day, thus suggesting storage capacity of 960 kg. This excludes storage for the H70 dispenser. Sizing for H70 service will depend on the number of vehicles eventually to be serviced.

As for placement of storage, there was a fairly uniform consensus that underground storage would be excessively complex and expensive, although two major companies have apparently developed intellectual property around the concept.

That leaves two recommended options for consideration. The first would be conventional on-ground storage. The second would be canopy storage. Canopy storage has the drawback that type 1 and type 2 cylinders are quite heavy (although there are now 95 kPa type 4 cylinders available, which are much lighter). However, canopy storage was used for the original Shell Santa Monica hydrogen. It was also a component of a winning student design competition put on by the National Hydrogen Association. Canopy storage has the important advantage that it frees up a lot of parking space. It also alleviates some of the safety aspects, as standoffs and bollards would not be required.

E.5 FINANCING STRATEGIES

The majority of financing strategies identified involved some form of debt financing. The good part of this is that many of these opportunities are specifically focused on transportation and/or clean technology. The obvious drawback, though, is that the debt needs to be serviced. The only clear means for servicing debt is either raising fares or adding new tax levies. Raising fares doesn't seem workable as the fares would likely need to be raised so high as to put public transit out of reach for the people who need it most. Adding new taxes is also likely to be unpopular.

Alternatives to debt financing include grants. Federal grants might be available under Low-No Grants and under BUILD Transportation Grants. BUILD is likely a long shot as in 2019, only one of 55 BUILD grants addressed zero-emission transportation.

Please note, there are also state energy program (SEP) grants, which would be issued through the Ohio Development Services Agency.

Finally, there are Ohio Transportation Partnership Program (OTPP) funds for which the program detail for 2020 have yet to be released.

A last financing opportunity might come through Private-Public Partnership (P3) opportunities. Two companies providing SMR equipment have expressed interest in a P3 arrangement by which they would retain ownership and responsibility for producing the hydrogen on site and would sell the hydrogen to SARTA under agreed upon terms. A single photovoltaic equipment supplier also expressed interest in a P3 arrangement under which SARTA would simply purchase electricity while they retain ownership and operational responsibility.

1. EVALUATION OF HYDROGEN GENERATION ON SITE

1.1 SARTA BACKGROUND

This project evaluates possible pathways for renewable hydrogen production on-site at SARTA. It is to include evaluation of hydrogen storage options on-site and rough order magnitude pricing. The results of these evaluations will be compiled in a Final Report as a deliverable. The first sub-task is to evaluate the amount of hydrogen required for SARTA operations. The amount of hydrogen required to operate the current fleet is captured from reports and interviews. By reviewing plans for additional vehicle procurement an estimate of needs for the immediate and foreseeable future is provided.

The Stark Area Regional Transit Authority (SARTA) operates the third largest Hydrogen Fuel Cell Electric Bus (FCEB) transit fleet in the Western Hemisphere. The current fleet will have 11 40-foot FCEBs in operation, with the last two being deivered, and one additional FCEB to be ordred, for a total of 12. An additional order for five (5) fuel cell paratransit vehicles is being finalized. The fleet is refueled from delivered liquid hydrogen (LH_2) stored on site in a 2,400 kg liquid hydrogen tank. The refuel island has two dispensers (two refuel positions) with H35 (350 bar or 5,000 psi) refuel nozzles. The refuel island is being expanded to four dispensers (4 refuel positions for FECBs) and a separate dispenser that could host a H70 (700 bar or 10,000 psi) nozzle.

When SARTA built the hydrogen refueling station (HRS), the authority had a goal to transition to a renewable hydrogen capability in the future. Renewable hydrogen could possibly be produced by an electrolyzer powered by a solar array or from purchased wind electricity. Another possibility was a stationary steam methane reformer powered by renewable natural gas sourced from a biodigester located at a nearby Water Reclamation Facility (WRF) or from a local landfill. These pathways to renewable hydrogen will be examined in more detail in the following sections.

1.2 REQUIRED HYDROGEN FOR FLEET OPERATIONS

SARTA presently is operating a fleet of 11 fuel cell electric buses (FCEBs), two (2) of which are being delivered, and with one on order, will have a total of 12 FCEBs. The current fleet of buses is fueled daily, typically with 30 to 35 kg of hydrogen per fueling using H35 nozzles on two available dispensers. In addition, five (5) fuel cell powered paratransit vehicles (FCPV) are planned for delivery. The FCPVs will have on-board hydrogen storage of 15 kg at 35 MPa, so daily 10 to 12 kg fill-ups can be anticipated.

Figure 1: Air Products hydrogen dispenser

Operating on weekdays only, 12 FCEB refueling would have to take place with ten-minute fills using the four dispensers. This would be expected to require a total of 360 to 420 kg of hydrogen per day. The daily total of hydrogen necessary for the FCPVs requires an additional 50 to 60 kg per day. Together the daily hydrogen requirement could be as high as 480 kg per day. Minimum specification would be 500 kg per day. However, depending on fuel economy, 600 kg per day is highly suggested. Based on the data we have received, the H35 dispensers are suitable for the 12 FCEB with fast fill in about two hours plus faster fills for the five FCPVs. An additional dispenser with H70 capability should be added for refueling future light-duty vehicles.

Based on lessons learned so far from across the country and in particular with the California *Hydrogen Highway* initiative, station operators highly recommend installing double redundancy and having normal operation at part load, whether we are talking about steam methane reforming or hydrogen generation using an electrolyzer. This would put peak production capacity at or near 1000 kg/day but would still permit full station operation in the event of an equipment outage, whether scheduled or not. Double redundancy may not be necessary if the liquid hydrogen system is retained as a backup but should be considered in all planning. In particular, it has been pointed out repeatedly by others that it is far easier and more cost effective to add extra capacity at the start of a project rather than trying to upgrade or uprate later on.

1.3 RENEWABLE PATHWAYS UNDER CONSIDERATION

SARTA has pursued a vision of transitioning to cleaner, and potentially total renewable mass transit for over a decade. This goal is even captured in SARTA's mission statement, which emphasizes *sustainable mobility options*. SARTA's current fleet of 113 buses includes 72 vehicles operating on alternative fuels.[1] Fifty-seven of these operate on compressed natural gas (CNG), 11 on hydrogen, and four are diesel electric hybrids. This is all part of a broader vision of making Ohio and much of the Midwest *a national leader in the adoption of hydrogen fuel cell-powered vehicles through education, advocacy and research*.[2] In the short term, the transition to cleaner and renewable mass transit also opens up alternative sources of funding. These are discussed in more detail in Section 3.

[1] Finnicum, M. Hydrogen Fuel Cell: The Energy of Today Powering SARTA Today. SARTA June 7, 2019.
[2] Jokinen, K. Hydrogen Roadmap for the U.S. Midwest Region. CALSTART July 21, 2017.

> *SARTA's mission statement reads:*
>
> *"SARTA is committed to enhancing the quality of life for our community by providing efficient, affordable and sustainable mobility options for Stark County."*

One possible path to generating renewable hydrogen is to create biogas at a local water reclamation facility or landfill. After the biogas is conditioned for either injection into a local natural gas (NG) pipeline or transported directly to SARTA via a new pipeline, NG could be used to generate "renewable" hydrogen. A tri-generation plant could use this gas stream to generate combined hydrogen, heat and electric power (CHHP). Another possibility is to install a steam methane reformer (SMR) to generate hydrogen alone on site from the renewable methane reformer. Biogas could also be used to power on-site electricity generation using either stationary reciprocating engines or station gas turbine power generators. The details of this latter option are being studied in a separate task under this project.

A second alternative is to install solar photovoltaic power generation that can be used to power an electrolyzer, as well as provide additional power for compression, chilling, and general utilities. This could be done with the power being delivered to the grid to offset carbon-intensive electric power during daylight and power being tapped from the grid as needed around the clock to run the station. Alternatively, solar power could be stored in a battery bank on site and used as needed.

A third alternative considered is wind power generation. Eastern Ohio is not particularly favorable to wind generation because of low wind speeds. However, there is significant existing and planned wind power in the western part of the state and elsewhere, and there are mechanisms by which that power can be acquired under contract and then be delivered via the local utility.

1.3.1 BIOMASS OPPORTUNITY AT LOCAL WATER RECLAMATION FACILITY

The City of Canton, Ohio has a Water Reclamation Facility (WRF) approximately a mile from the SARTA facility. The WRF is responsible for treating all sanitary sewage that flows to the facility from a variety of sources throughout the greater Stark County area. One concept under consideration is incorporation of an anerobic biodigester using WRF wastewater as the feedstock. The biodigester would provide a stream of biogas for a high temperature fuel cell. Processing of the biogas for the removal of contaminants is generally necessary.

The current concept is to generate and process the biogas into renewable methane at the WRF then locally inject it into the natural gas network if state regulations permit injection. A natural gas source could be used to feed a large stationery fuel cell at the SARTA facilities. The fuel cell could be used to generate combined heat and power for supporting heating facility building(s) and powering an electrolyzer to produce hydrogen on site.

The City of Canton Water Reclamation Facility is a tertiary treatment facility designed for an average flow of 39 mgd (million gallons per day) and a peak flow of 88 mgd.[3] Currently, though, the plant processes between 30 and 32 mgd wastewater.[4] The plant wet stream process consists of mechanical screening, raw wastewater pumping, grit removal, preaeration, primary clarification, activated sludge secondary treatment, secondary clarification, effluent filtration, effluent disinfection, and dechlorination.

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[3] https://www.cantonohio.gov/203/Water-Reclamation-Facility-WRF

[4] Gellner, T.M. North America's Largest... Canton MBR Water Reclamation Facility Under Construction. Plant Retrofit Solutions, Summer 2016. American Membrane Technology Association.

The facility is based on membrane bioreactor (MBR) technology. It is a new facility, approved in 2013, with construction started in 2014 and completed in 2018. MBR is generally recognized as a low installed cost approach to wastewater treatment, with a smaller footprint than other technologies. However, it is also recognized as having higher operating costs, in some part due to the need for frequent replacement of filter modules.

Treated effluent flows by gravity to Nimishillen Creek. The handling of solids consists of gravity thickening of primary and secondary sludge, dewatering by belt filter presses, and multiple hearth incineration.

Figure 2: City of Canton Water Reclamation Facility

Three calculations lead to an estimate of the potential hydrogen from WRF biogas feedstock. These are (1) annual methane potential available from the WRF average flow, (2) biogas purification for natural-gas-quality biomethane, and (3) biomethane conversion to hydrogen.

Annual methane potential equation for the WRF is shown below.[5]

$$annual\ methane\ potential = q * \frac{1 ft^3 biogas}{100\ gal\ wastewater} * \frac{0.0283 m^3 biogas}{ft^3 biogas} * \frac{65\%\ m^3 CH_4}{m^3 biogas} * \frac{0.622\ kg\ CH_4}{m^3 CH_4}$$

Where q is the wastewater flow in gallons per year.

$$q, annual\ average\ flow = 39 mgd * 365\ days = 14{,}235\ million\ gallons$$

From the equation above:

$$\begin{aligned} &annual\ methane\ potential \\ &= 14{,}235{,}000{,}000 * \frac{1 ft^3 biogas}{100\ gal\ wastewater} * \frac{0.0283 m^3 biogas}{ft^3 biogas} * \frac{65\%\ m^3 CH_4}{m^3 biogas} * \frac{0.622\ kg\ CH_4}{m^3 CH_4} \\ &= 1{,}733{,}466\ kg\ CH_4\ per\ year \end{aligned}$$

$$1{,}733{,}466\ kg\ CH_4\ per\ year * \frac{2.204\ lb}{kg} * \frac{22{,}874\ Btu}{lb} * \frac{1 MMBtu}{10^6 Btu} = \frac{87{,}391\ MMBtu}{year}$$

[5] 60283_NREL biogas to h2 equations

The hydrogen potential assumes a conversion of the methane in biogas to biomethane, which is natural gas quality, and subsequent conversion by steam methane reforming (SMR) to hydrogen. Potential pathways for biomethane include injection into natural gas pipelines, use as a feedstock in an SMR process for conversion to hydrogen, and other natural gas end uses, such as stationary heat and power.

The process of purifying the methane content in biogas can use various chemical and biological purification processes. Membrane purification, a purely physical process, is where a thin membrane is used to separate the methane from the input biogas stream. Typical input stream is composed mainly of methane, carbon dioxide, and saturated water. The methane stream is then approximately natural gas quality, although some other processing may be required to remove specific contaminants.

Tail gas, the other output stream, is composed of primarily of carbon dioxide and a small amount of methane. During purification, the tail gas is combusted in a thermal oxidizer to minimize methane emissions. In order to do this, electricity is used for compression for movement through the membrane, and the thermal oxidizer is fueled by biogas. It has been estimated that the efficiency of the separation of biomethane from biogas is 87%; this includes a 90% membrane efficiency as well as a small amount of input gas being combusted in the thermal oxidizer for emissions reduction. As shown in the equation below, biomethane potential is then 87% of the total methane available in the original biogas. The electricity usage is not taken into account, but total system life-cycle analyses would incorporate it. [6]

Biogas to biomethane purification factor

$$biomethane\ potential = 87\% * methane\ content\ of\ biogas$$

$$= 0.87 * 1{,}733{,}466\ kg\,CH_4$$
$$= 1{,}508{,}115\ kg\ CH_4\ \ or\ \frac{4{,}130\ kg}{day}$$

Using the earlier equation:

$$\frac{1{,}508{,}115\ kg\ CH_4}{year} * \frac{2.204\ lb}{kg} * \frac{22{,}874\ Btu}{lb} * \frac{1\ MMBtu}{10^6 Btu} = \frac{76{,}031\ MMBtu}{year}\ \ or\ \frac{208.3\ MMBtu}{day}$$

Natural-gas-quality biomethane can be used as a substitute for natural gas in an SMR process to produce hydrogen. The U.S. Department of Energy's H2A Production model case study for central production of hydrogen from natural gas provides the conversion factor for converting biomethane to hydrogen.[7] The energy content in natural gas is mainly methane (CH4), and this feedstock usage is converted to a conversion factor of 3.295 kg CH4/kg hydrogen ignoring the process electricity for SMR. This results in an annual amount of 457,698 kg H2 (1254 kg/day). With the minimum requirement presently at 500 kg/day, by these estimates, a flow rate from the WRF would be in the range of 15.55 mgd.

At this scale the cost of a complete anaerobic digester with methane recovery would be in the range of $100 - $150 million[8] according to an estimate by SAMCO Technologies prepared in August 2019. A paper by Guo, et al. (2014)[9] suggests that this estimate is at least at the right order of magnitude.

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[6] Saur, Genevieve, and Anelia Milbrandt. *Renewable hydrogen potential from biogas in the United States*. No. NREL/TP-5400-60283. National Renewable Energy Lab. (NREL), Golden, CO (United States), 2014.

[7] https://www.nrel.gov/hydrogen/h2a-production-models.html

[8] https://www.samcotech.com/anaerobic-wastewater-treatment-systems-cost-factors/

[9] Tianjiao Guo, James Englehardt and Tingting Wu, Review of cost versus scale: water and wastewater treatment and reuse processes, Water Science & Technology | 69.2 | 2014.

1.3.1.1 PIPELINE CONNECTION FROM WRF TO SARTA

An earlier embodiment of this concept involved connecting the WRF to SARTA via pipeline. For small diameter pipes where materials are a small part of the total cost, typical natural gas pipeline installation cost is easily in the range of $400-500k per mile.[10] Materials and labor are about 60% of this cost. Rights of way, trenching and other costs account for the rest. Therefore, the feasibility of installing a pipeline might depend heavily on whether there is an existing above/underground conduit that could be purposed for colocation of a natural gas pipe. This would also likely require that the gas be odorized at the point of compression (the Tri-Gen facility includes gas cleanup to remove the odorant).

In addition, typical natural gas pipelines are not installed into a built environment. Having to accommodate roadways, buildings and private property could drive up costs significantly over that for "typical" gas pipelines.

To eliminate the need for a new natural gas pipeline, and associated costs, the Tri-Gen facility itself could be collocated at the WRF, with the hydrogen being transferred to SARTA via tube trailer using a dedicated tractor and trailers.

1.3.1.2 QUASAR ENERGY ALTERNATIVE

An alternative to passing the entire waste stream through a digester has been proposed by Quasar Energy Group in their *Response to RFI* dated 31 May 2019.[11] In a follow up call to Alan Johnson, VP Project Development and Management,[12] Mr. Johnson explained that they thought it should be possible to divert the sludge from the MBR process to a digester, possibly with a small slip stream of untreated wastewater. This could potentially produce much more biomethane than needed by SARTA and represent a revenue stream for the city, while reducing the cost of off-site disposal of the processed sludge. This would be substantially smaller than the cost of a digester plant to handle the entire waste stream and significantly less expensive.

Quasar's concept involved compressing the biomethane into tube trailers that would then be towed to SARTA for use by a reformer or other downstream equipment.

Speaking strictly off the cuff, Mr. Johnson guessed that the project might have a payback period on the order of 10 years, after which it would serve as a revenue stream for the City of Canton.

Currently, the sludge from the WRF is shipped to a local landfill (American, discussed below) where it is already being converted to landfill gas. The landfill gas is collected and processed into high Btu gas that is compressed and pumped into the local grid. As a result, it is not clear what advantage there would be to building a new facility for digesting it, as well as a new processing plant and compressor station.

1.3.2 BIOGAS OPPORTUNITY AT LOCAL LANDFILL

There are two municipal landfills located in Stark County, American Landfill and Countywide Landfill. American is operated by Waste Management and is located near Waynesburg in Sandy Township. Countywide is operated

[10] Parker, N. Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs. UCD-ITS-RR-04-35. December 2004.
[11] Quasar Energy Group, Response to RFI 2019-1: Extracting Compressed Natural Gas from the City Water Reclamation Facility. 31 May 2019.
[12] Personal communication: Alan Johnson, Quasar Energy Group 8 November 2019.

by Republic and is located in East Sparta. Both produce landfill gas (LFG) that has the potential to be collected for use. For purposes of this study we will focus on American, as it provides more information on its website.

The American Landfill was opened in 1976.[13] It has 1,084 total acres with 396 acres currently permitted for landfill activities. It is expected to have a remaining useful life of 84 years and currently processes 335,000 tons of waste annually.

American Landfill has a total of 155 gas collection wells in a collection system that was started in 1996.[14] The collection system includes the wells, header and lateral pipes, condensate removal, and balance of plant including a utility safety flare.

In June 2003, Toto Energy, Inc started a medium Btu plant on site.[15] The site produces enough gas to heat 6,155 households. The gas is compressed to 600 psig (41 barg) and then goes to cleanup units to remove H2S and siloxanes.

The total of 4 million cubic feet per day LFG is then upgraded to 2 million cubic feet of high Btu natural gas equivalent (renewable natural gas, or RNG) that is sent to Dominion East Ohio via pipeline injection. SARTA would be able to use about five percent of this total to meet the minimum requirement of 500 kg-H2/day via SMR, or as much as 25% of the total for operation of a tri-generation MCFC on site.

The project team has contacted Dominion Energy and spoken with the account representative responsible for Stark County.[16] Dominion has confirmed that there is sufficient pipeline capacity at SARTA for operation of on-site hydrogen generation using RNG from American, or any other RNG producer SARTA wishes to contract with.[17]

On January 17, 2020, a conference call was held between Mack Smith of Dominion Energy, Scott O'Neill of Waste Management and CALSTART contractor, Jerald Cole. Scott O'Neill is Director of Biogas Marketing for Waste Management. During this call we learned about the availability of Renewable Natural Gas (RNG) for the SARTA expansion.[18] Mr. O'Neill shared that the gas from American Landfill is currently all under contract. However, he added that it is a short-term contract and that the gas might become available in the time frame for the SARTA project.

Outside of North-Eastern Ohio, he further added that there was available RNG from Louisville, KY, St. Louis, IL, and Ferris, TX that could be delivered to SARTA by displacement. All of these sources would be able to meet the needs of the SARTA expansion under any of the scenarios currently under consideration. In addition, he told us that American Landfill has the ability to increase their production enough to cover SARTA needs, and the collection and cleanup equipment also has the necessary capacity – if the landfill management have "the stomach" to increase their output. Contracts, he said, are currently going for $15/dekatherm (approx. $15/MMBtu).

Mr. Smith then added that Dominion may be interested in participating in the SARTA expansion project. What that participation would entail was left unsaid.

[13] http://americanlandfill.wm.com/facility-information/index.jsp
[14] http://americanlandfill.wm.com/landfill-design-construction/gas-collection-and-management-system.jsp
[15] http://americanlandfill.wm.com/facility-information/landfill-gas-to-energy.jsp
[16] Sharnyse Brice, Commercial Gas Account Manager, Dominion Energy.
[17] Personal communication: Dan Bose, Dominion Energy 11/6/2019.
[18] Personal Communication, Mack Smith, Dominion Energy, Scott O'Neill, Waste Management.

1.3.3 ON-SITE SOLAR PHOTOVOLTAIC POWER GENERATION

Canton, OH has an average insolation of 4 – 4.4 peak hours per day (depending on the calculator used) with the greatest solar potential during the summer months (May – Aug) and limited sunlight during December and January. Solar photovoltaic renewable electricity could be provided by a combination of rooftop, stationary (ground mounted), and carport solar panel installations. It also can be considered as either a partial or total solution to renewable power generation for the hydrogen station (including generation) and local microgrid.

The team has estimated that using only the available footprint at SARTA, there is room for 490 kW of rooftop solar and as much as 650 kW of carport, or canopy, capacity. While this would not be enough to provide for an electrolyzer for on-site renewable power generation, it could be augmented by alternative local electricity sources using RNG for direct power generation via genset.

However, if we assume a goal of providing all power for the station via a local solar photovoltaic installation, we start by recognizing that the electrolyzer will use as much as 2 MW power 24 hours per day. For estimating purposes, an additional 300 kW is assumed for balance of plant operations. This means that the power supply needs to provide

$$2.3\ MW\ x\ 24\ h\ =\ 55.2\ MWh\ each\ day$$

Assuming an average 4.2 peak hours per day the capacity of the installation needs to be

$$\frac{55.2\ MWh}{4.2\ h} = 13.2\ MWAC$$

Assuming 95% inverter efficiency

$$\frac{13.2\ MWAC}{0.95} = 13.9\ MWDC$$

This is a utility scale installation and benefits from significant economies of scale. In order to get an idea of the scope of such an installation the team contacted Jonathan Port, CEO of PermaCity Corp. PermaCity recently completed a project at this scale near Los Angeles, CA. To understand how large a 13.9 MW solar installation would be, consider the following figures of merit.

Configuration	Rooftop	Carport	Freestanding
Density W/sq. ft.	13 W/sq. ft.	17 W/sq. ft.	8 W/sq. ft.
Cost $/W	$1.65	$2.10	$1.30

Table 1: Figures of merit for different solar photovoltaic installations at utility scale[19]

This means that for a strictly rooftop configuration, a total roof area of 1.07 million square feet would be needed. Depending on the exact configuration, a mixture of rooftop, carport and freestanding would have an estimated cost of $18 - $29 million. The figure below shows the 16.4 MW solar installation completed by PermaCity in Southern California. It covers approximately 50 acres of roof space and is the largest solar PV installation (by power produced) in the world as of this writing. To reduce the total area required at SARTA, a combination of

[19] Source: Personal communication with Jonathan Port, CEO PermaCity. October 2019.

roof and carport could be employed. Carport (or parking lot) installations can be tall enough to drive a semi underneath with plenty of room to spare.

Freestanding solar installations are generally the least expensive for both hardware and construction, but usually require a land lease agreement, which can increase the cost significantly.

Figure 3: The 16.4 MW Westmont solar installation in the Port of Los Angeles. Image Credit: PermaCity.

Two major advantages of solar photovoltaic renewable energy at SARTA are that it is local and that the levelized cost of electricity over 20 years or so can be quite competitive with other local or on-site renewable energy sources. In addition, it is possible to finance the entire project via purchase power agreements (PPAs), with SARTA paying only for the electricity.

Down sides of solar include the fact that it isn't really grid independent. Even when the sun is shining, demand may not be well matched to production, leaving a portion (or most) of the generated electricity to be sold into the grid, only to be bought back later in the day when sunshine is reduced or altogether absent.

1.3.4 WIND ENERGY

Wind energy is probably the simplest form of renewable energy to obtain at SARTA. Contracts can be made with suppliers across the country (and presumably Canada and Mexico) to generate load that will offset local fossil fuel generation. AEP Ohio can deliver by displacement wind power that SARTA contracts through various PPAs.

Advantages of wind energy contracts include the low cost. In 2018, utility PPAs for wind energy in the U.S. were in some cases coming in at less than $0.02/kWh.[20] Even figuring in the cost of delivery and infrastructure

[20] Wiser, R. and Bolinger, M. U.S. Department of Energy 2018 Wind Technologies Market Report. Office of Energy Efficiency and Renewable Energy. August 2019.

maintenance, this is one of the lowest cost ways of contracting for long term renewable electricity. The downside is that as with large scale solar, it isn't grid independent, leaving in place all distribution and rider costs. Also, unlike solar, renewable wind energy is not local. Even within the state of Ohio, most of the wind energy is produced in the western part of the state. It is even more likely that it will come from neighboring states such as Indiana, or even from more distant states such as Texas.

1.4 ON-SITE HYDROGEN PRODUCTION PATHWAYS

On-site production of hydrogen is generally more expensive, and at best, on par with the cost of delivered hydrogen. However, on-site production can provide security of supply, especially when it is backed up with the possibility of delivered hydrogen in the event of scheduled or unscheduled equipment shutdown.

Recent experiences in both Southern and Northern California have shown that reliance on centralized hydrogen production – at least for the time being – can result in widespread shortages. Even though Air Products' Santa Clara facility is back online, there are still frequent reports on social media platforms of stations having little to no hydrogen available. Likewise, a temporary shutdown of the Air Products Transfill facility[21] in Wilmington, CA left Southern California FCEV drivers scrambling to find fuel from other suppliers such as Air Liquide. Stations with on-site production, including Riverside, Burbank, Ontario, and Newport Beach have limited capacity, but continue to produce hydrogen on site when central supply is unavailable.

For this study, we looked at the three most likely opportunities for on-site production of hydrogen at SARTA. These include tri-generation molten carbonate fuel cell (Tri-Gen MCFC) from FuelCell Energy, on-site electrolysis, and on-site steam methane reforming (SMR). Other possible production methods were not considered practical or viable for the SARTA FCEV refueling station expansion. Examples of methods not considered for this report include solid waste pyrolysis, coal gasification, autothermal reforming (ATR), and exothermic gas generators (partial oxidation).

[21] https://www.marketwatch.com/press-release/air-products-to-build-second-liquid-hydrogen-production-facility-in-california-2019-01-07

In a molten carbonate fuel cell, air and CO2 are fed to the cathode side catalyst where they react with electrons to form carbonate ions. On the anode side, natural gas and steam react to produce hydrogen, CO, and CO2. Carbonate ions diffuse across the electrolyte to the anode where they react with hydrogen to form CO2 and water, releasing electrons.

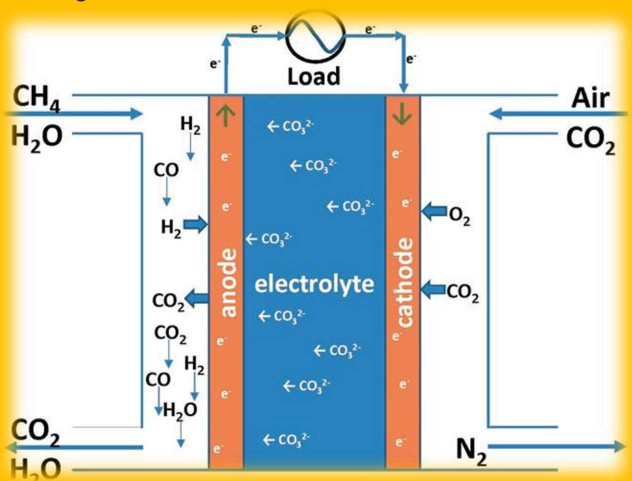

Figure 4: Molten carbonate fuel cell

As part of the over-all plan for use of biomethane, SARTA would contract with Dominion East Ohio for biomethane. A Tri-Gen MCFC facility could then convert biomethane to electricity, hydrogen, and water. In the first part of this process, water and fuel react over a nickel catalyst to form a syngas of mainly hydrogen and carbon monoxide.

$$H_2O + CH_4 \rightarrow 3H_2 + CO$$

Carbon monoxide subsequently reacts with water to create additional hydrogen.

$$CO + H_20 \rightarrow CO_2 + H_2$$

The first of these reactions is called *steam reforming* (SR) and the second is the *water gas shift* reaction (WGS).

The hydrogen produced in these reactions is almost immediately consumed by reaction with carbonate ions at the anode. This process releases electrons and is the source of electric current.

$$H_2 + CO_3^{2-} \rightarrow H_2O + CO_2 + 2e^-$$

With a conventional MCFC without hydrogen generation, unreacted hydrogen in the anode exhaust is burned with air to preheat incoming reactants. In the FuelCell Energy Tri-Gen MCFC system, the hydrogen is instead separated from the other exhaust gases (mainly CO2 with some CO) and recovered as product.

Under baseload operation the Tri-Gen MCFC plant would produce up to 2.35 megawatts of electricity to provide power to the local microgrid, while also generating 1270 kg/day of hydrogen. This is clearly more than needed to support the daily fills of the FCEBs and FCPVs. Sales of excess hydrogen could offset some of the operation and maintenance (O&M) facility costs unless or until future expansion of the station is able to absorb the entire capacity (historically, on-site hydrogen generators have vented their unused product, as the economics of sale off site proved unfavorable). Otherwise the plant would be run at partial capacity during part or all of daily operations.

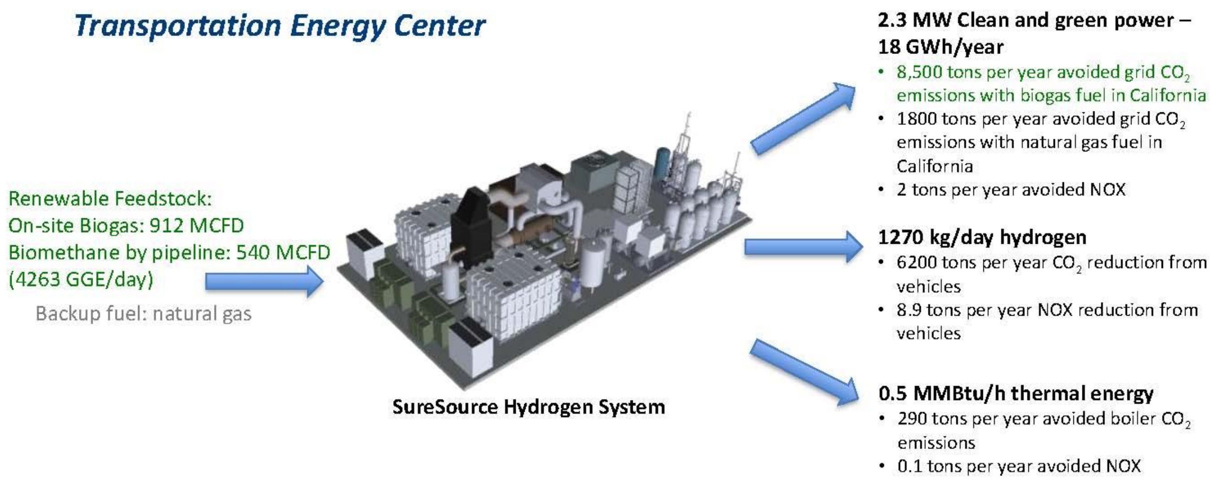

Figure 5: General layout of Tri-Gen facility. Image Credit: FuelCell Energy.

Capital cost for a turn-key FuelCell Energy (FCE) SureSource Hydrogen™ unit is $25 – 30 Million, depending on site-specific factors affecting installation. That does not take into account compression and storage of the hydrogen, nor does it factor in the cost of a substation for grid interconnect of the produced excess electricity. FuelCell Energy estimates the footprint for the tri-generation system, including customer-supplied compression and storage, is 100 ft by 200 ft. Scheduled maintenance occurs every six months and stack life is seven years. Availability is 90%, and the final hydrogen price per kilogram is between $5 and $10 depending on the cost of biogas and value of produced electricity.[22]

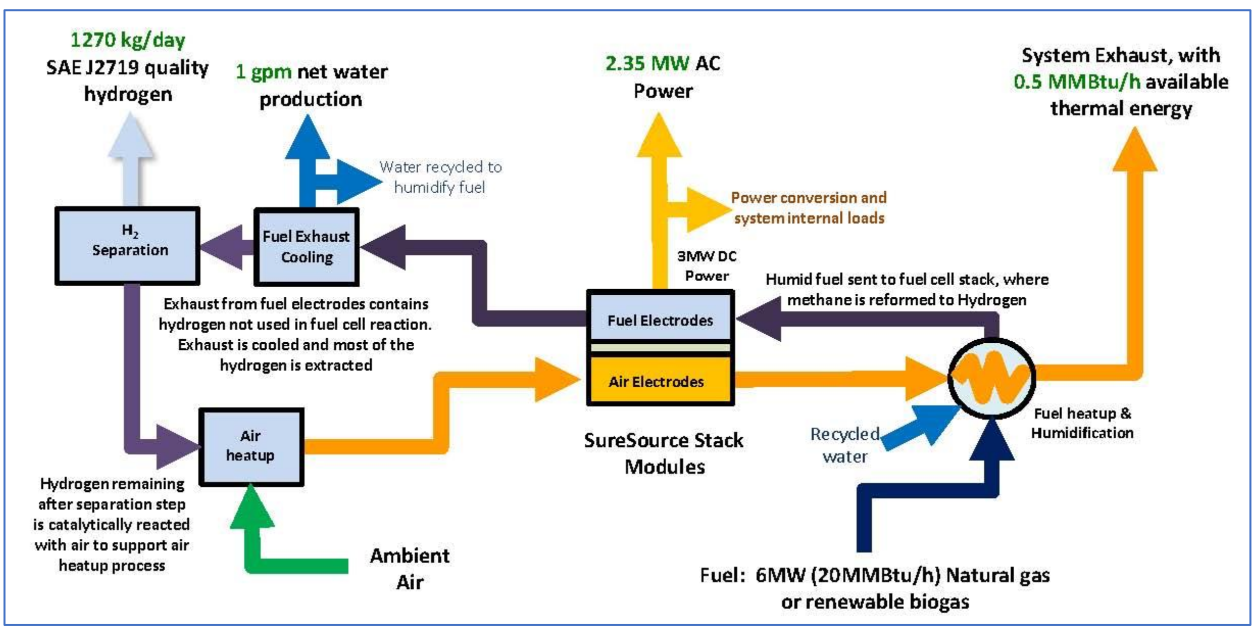

Figure 6: Hydrogen production via Tri-Gen MCFC. Image Credit: FuelCell Energy.

[22] Personal communication: Paul Fukumoto, Business Development Director, FuelCell Energy.

Another consideration is turn down. FCE says that the fuel cell itself can be turned down to 60% of design capacity (1.41 MWAC) but is designed for seasonal, rather than daily or weekly variation. Load changes are limited to 2.4 kW/min. This means that maintaining a microgrid will still require a means to offload power during diurnal load changes. This could be accomplished with batteries but would almost certainly require a grid interconnect as well.

As far as hydrogen generation turn down, FCE staff expressed uncertainty as to how this would work. It is possible that the unit could be set up to at least meet the maximum weekly demand. In this scenario, day to day demand variations could be handled by increasing the storage capacity – especially for less expensive lower-pressure storage.

1.4.2 ELECTROLYZER AND SUPPORTING EQUIPMENT

The transit agency would like to explore purchase of a polymer electrolyte membrane (PEM) electrolyzer to produce 600 kg of hydrogen per day[23] with dispensers at 350 bar (4) and a dispenser at 700 bar with appropriate storage and compression. The hardware details for such a configuration need to be sufficient to allow rough order of magnitude (ROM) pricing. With redundancy, this could be easily 1000 kg/day.

PEM electrolysis is somewhat different from other water electrolysis processes in that the membrane is an electric insulator but also a conductor of protons.

Water dissociates at the iridium anode into gaseous oxygen, protons, and electrons. The electrons are drawn out of the electrode by a DC power supply and injected into a platinum cathode. Protons diffuse across the membrane from the anode to the cathode and then recombine with electrons at the cathode to produce gaseous hydrogen.

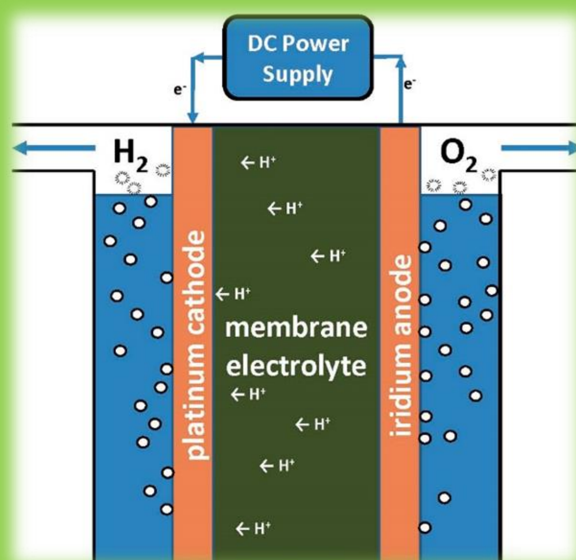

Figure 7: PEM electrolysis

One concern that was expressed by representatives from two electrolysis equipment suppliers, Nel and ITM Power, was the remoteness of Canton relative to more coastal locales. In general, both companies expressed a desire to site units close to maintenance personnel and facilities and where spare parts can be inventoried locally. Nonetheless, both companies still expressed interest in the project and provided significant input to the preparation of this report.

[23] With redundancy this could increase to 1000 kg per day.

PEM electrolysis at its simplest is the direct opposite of a fuel cell. Electric current is *supplied*, and water is split into oxygen and hydrogen. At the anode of the PEM cell, water is oxidized to produce gaseous oxygen, protons, and electrons.

$$H_2O \rightarrow\ 2H^+\ +\ 2e^-\ +\frac{1}{2}O_2$$

The protons diffusion across the membrane and recombine with electrons to produce gaseous hydrogen.

$$2H^+ +\ 2e^- \rightarrow\ H_2$$

PEM electrolysis can be carried out under pressure, typically around 30 bar, and that can reduce the energy needed for compression.

1.4.2.1 AIR LIQUIDE ELECTROLYZER

A system design proposed by Air Liquide is shown below. The design uses a 2 MW electrolyzer that can produce about 880 kg/day and compressors that can process 480 kg/day if all three compressors are running. The amount of storage required is quite large to be able to dispense hydrogen to 12 buses in a short amount of time. Linde has since updated its proposal to include two compressors each capable of processing 880 kg/day to 500 bar.

From the Linde proposal:

Below are our expected performances based on preliminary calculations with the current information provided:

The compressor will take the hydrogen from 30 bar to 450-500 bar that will then be stored into ground storage based on Type I tubes. The ground storage required was calculated by performing simulations to meet the requirements of filling (4) buses simultaneously and all 350 bar vehicles in under 5 hours. From the storage, there will also be a chiller to cool the hydrogen down to be able to perform fast fills and will then feed the (4) dispensers (2 existing and 2 new). Below is the estimated fill sequence used to calculate the ground storage to meet the simultaneous fueling of 4 buses along with filling all 17 vehicles at 350 bar in 5 hours:

- *4 buses fill up in 25 min (slow fill) at 35 kg each (140 kg total)*
- *Wait time of 65 minutes for system to repressurize*
- *Next 4 buses fill up in 25 min (slow fill) at 35 kg each (140 kg total)*
- *Wait time of 107 minutes for system to repressurize*
- *Next 4 buses fill up in 11 min (fast fill) at 35 kg each (140 kg total)*
- *Wait time of 35 minutes for system to repressurize*
- *Last 1 bus and 3 paratransit vehicles fill up in 11 min (fast fill) at 35 kg for bus and 12 kg each for the paratransit vehicles (71 kg total)*
- *Fill final 2 paratransit vehicles fill up in 11 min (fast fill) at 12 kg each (24 kg total)*
- *Total time to fill all vehicles is 4.83 hours.*

The reason for the wait time is due to the amount of hydrogen that is used by filling 4 buses at the same time which is 140 kg in approx. 25 min. The flow rate of the electrolyzer and compressors is maxed out at 37 kg/hr, so it does not have enough flow to keep up with the demand, meaning that a large amount of storage is needed.

On the right is a station layout with preliminary, estimated dimensions. There are three different layouts Air Liquide has considered. The dispensers are not shown because it was assumed that the electrolysis system would not be next to the station dispenser pad but would be elsewhere.

The overall layout measures 50 x 150 feet but includes room for tube trailer delivery of backup hydrogen for use during scheduled and unscheduled maintenance periods.

Following that is a process flow diagram for the suggested station layout. This design incorporates three compressors to take hydrogen from the electrolyzer and put that into 450 bar storage with a capacity of nearly 900 kg, 420 kg of which is useable in a three-hour time frame. Even through the electrolyzer alone is capable of only 440 kg/day, production on weekends and other low demand periods can provide excess hydrogen in a buffer storage system for peak demands.

In this configuration the H70 dispenser system would principally draw hydrogen from the 450 bar storage and put that into high-pressure 850 bar storage.

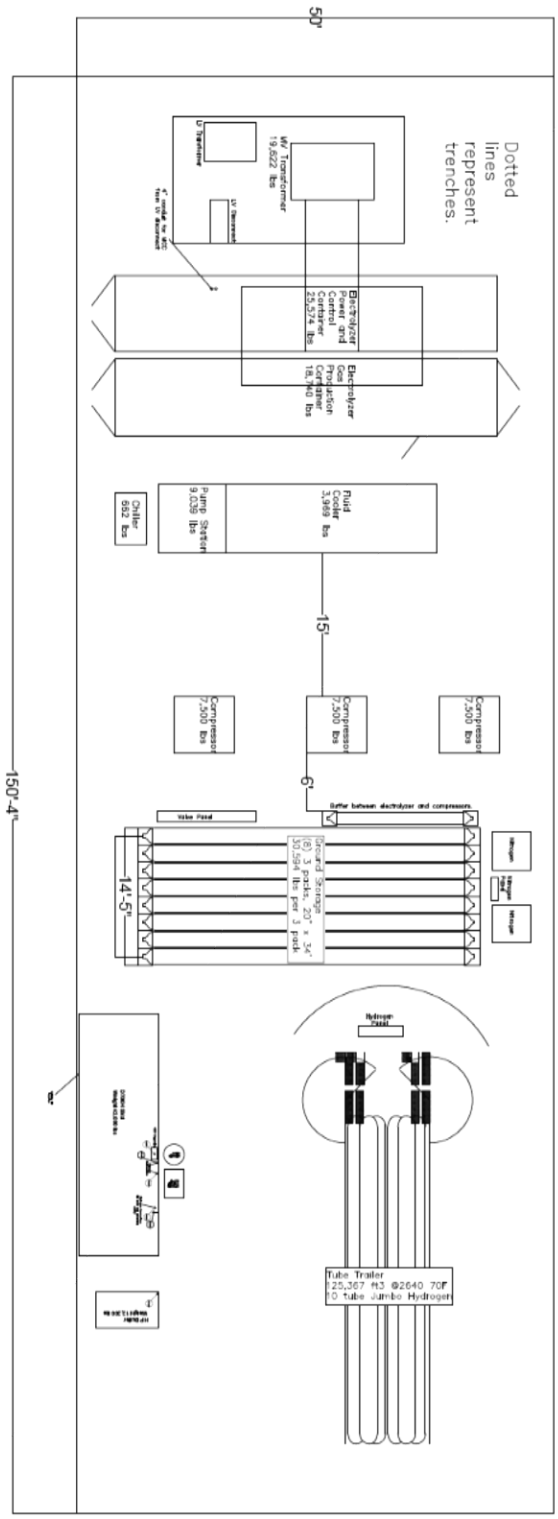

Figure 8: Potential station layout for the Air Liquide electrolyzer system. The dispensing island is not included.

For the H70 dispenser, Air Liquide has a new portable D700H portable station.

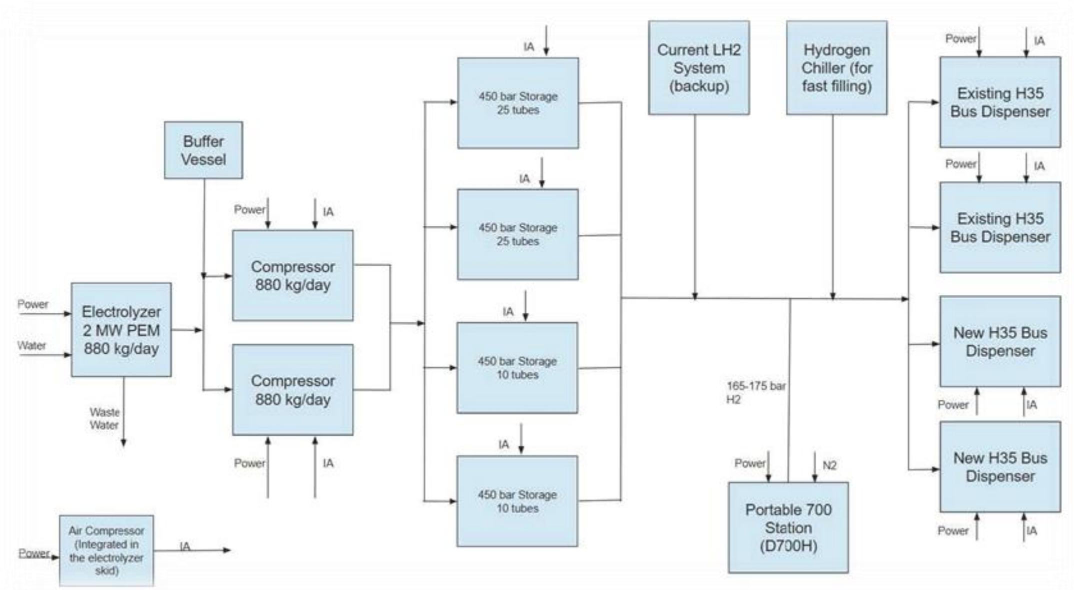

Figure 9: PFD of Linde electrolyzer solution

This new system design incorporates compression, storage, chilling and dispensing in a single skid-mounted package. According to Air Liquide, the base configuration is capable of delivering up to 35 kg/hr via back to back H70 T40 fills. It is also capable or dispensing up to 200 kg per day. At 35 kg/hr the portable dispenser is comparable with many existing standard permanent stations. For example, the UC Irvine station has demonstrated up to eight back-to-back fills of 4 – 5 kg each in a single hour.

Linde provided a preliminary cost estimate for the system as described. For the electrolyzer component, including storage and one extra dispenser for 350 bar fast fills, the cost is $9.3 million, not including site prep and installation. The cost for the D700H containerize H70 dispenser is roughly $1.6 million.

Figure 10: Air Liquide Portable D700H Dispenser. Image Credit: Air Liquide.

1.4.2.2 ITM POWER ELECTROLYZER

In discussions with Steve Jones of ITM Power,[24] he recommended the 2 MW configuration of their HGAS containerized electrolysis module. The total power requirement for this unit would be approximately 2.3 MW, including compression and ancillary equipment. Cost was estimated at $2.6 – $2.9 million for the electrolysis system, installed, plus about $2 million for compression.

Compression in this case calls for the bulk of the gas to be compressed to 450 bar. A dedicated bank of 450 bar tanks feeding a booster compressor would fill a 950 bar bank of storage tanks to supply the H70 dispenser.

Mr. Jones estimated that the total project cost, including storage and dispensers, would come in at about $6 million for the H35 buses and paratransit vehicles and an additional $1 to $2 million for the H70 component.

Figure 11: ITM Power HGAS containerized module. Image Credit: ITM Power.

1.4.2.3 NEL HYDROGEN ELECTROLYZER

Nel Hydrogen has recommended its MC400 containerized electrolyzer.[25] It is essentially the same as what SunLine Transit has deployed (discussed later) except that it has been compacted into three container modules that are preassembled and tested before shipping. Like the ITM electrolyzer, the Nel MC400 is a nominal 2 MW unit with a 30 bar outlet pressure capable of producing 892 kg/day H2. It is normally offered for an ambient temperature range of 40 – 105°F, but low and high temperature packages are available options.

The three key modules of the Nel unit and their footprints are as follows:

- Rectifier/Transformer 11 x 13 ft
- Electrolyzer container 40 x 8 ft
- Power supply container 40 x 8 ft

[24] Personal Communication: Steve Jones, ITM Power, 12 November 2019 plus other dates.

[25] Eddy Nupoort, Nel Hydrogen. Personal communication 9 December 2019.

This results in a total footprint of just under 800 square feet. In addition, there will be a process cooling unit (PCU) contained in a single 20-foot container.

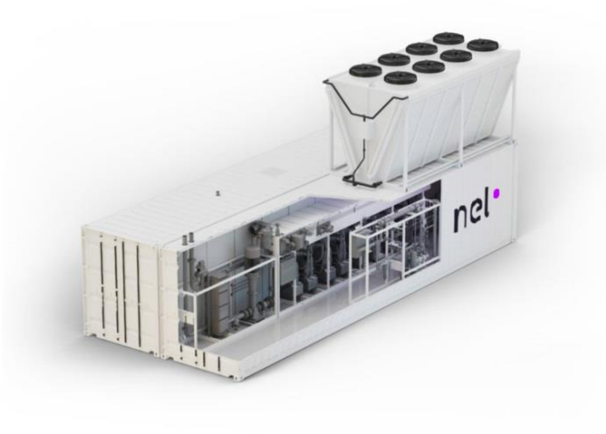

Figure 12: Nel Hydrogen electrolyzer module cutaway image. Image Credit: Nel Hydrogen.

For the SARTA bus refueling, two H2 station modules will be needed. These each have a footprint of 12 x 18 feet. The H2 station modules handle compression to 450 bar for medium-pressure storage. They also include the chillers for fast fills plus the two dispensers with two nozzles each.

Nel has eliminated the need for high pressure storage with a new 1000 bar compressor design that feeds directly to the H70 dispenser. This represents a significant capital equipment savings; however, the technology is not yet in wide commercial use.

Order of magnitude costs for the system are as follows:

MC400 Electrolyzer	$3 million
H2 Station modules (2ea)	$1.2 million each
Storage (450 bar)	$50k – $100k depending on capacity
PCU	$135k

Nel did not provide a price for the H70 dispenser, but others have quoted installed costs on the order of $450k for single nozzle dispenser with an integrated chiller. The chiller is estimated to account for $40k - $50k of the total cost. Total power required for operation of the entire station is roughly 2.5 MW 480 VAC 3-phase.

Nel reports that a new system design is currently in the works that should become available toward the end of 2020. The new system is reported to have an even smaller footprint and presumably lower installed cost as well.

1.4.2.4 SUNLINE TRANSIT INSTALLATION

In order to get an idea for the scale of a 2 MW electrolyzer project, a site visit was made to SunLine Transit Agency in Twentynine Palms, California. The site visit was conducted on 6 November 2019 and involved Bill Loper and Tommy Edwards of SunLine Transit, as well as Jerald Cole of Hydrogen Ventures, who is one of the authors of this report.

The SunLine Transit electrolyzer installation is a bit unusual in comparison with other electrolyzer projects at similar scale. It is centered around the Nel MC400 electrolyzer, but it is not containerized. Instead it has been built into a rather large building that includes office and desk space, as well as ample room for maintenance activities. The

Figure 13: Bill Loper of SunLine Transit in front of the electrolyzer building

building approach was selected not just to protect the electrolyzer, but also to protect personnel from the desert heat. Temperatures in the Palm Desert location can easily exceed 120°F during extreme summer weather, with typical daytime highs near 110°F. Much of the station equipment, in addition to the electrolyzer, was supplied by Nel. A Nel representative has stated that it is unlikely they will do another installation like SunLine, as they are focused on containerization as a way of reducing both installed cost and footprint.

The building measures 60' x 60' and is split in half down the middle. The right side houses the power conditioning systems and refrigeration equipment as well as water purification. Water is first filtered and then passes through deionization beds before being delivered to the PEM stacks. Electricity is supplied to the building at 1200 VAC and is rectified and transformed to 2 MW of 12,000 VDC power for the stacks.

Figure 14: PEM Electrolyzer stacks at SunLine Transit

The left side of the building contains all the equipment, including the electrolyzer stack, that process or conduct hydrogen.

Figure 15: High- and intermediate-pressure storage at SunLine Transit

This includes gas purification and conditioning systems. The gas is first chilled to physically remove water. It then passes through desiccant and molecular sieve beds to remove any trace impurities. The left side of the building also contains a precompressor that collects the hydrogen from the electrolyzer at 30 bar and feeds it to intermediate pressure storage at 210 bar (3,000 psig).

In the electrolyzer room extra attention is paid to adequate ventilation, and there are hydrogen leak detectors placed in numerous locations throughout.

SunLine has 500 kg hydrogen storage capacity in Type I cylinders. There are eight intermediate-pressure cylinders in two rows of four tanks each. Above those are two rows of six cylinders each for high-pressure (430 bar) storage.

The storage cylinders are arranged in two banks such that one set of intermediate pressure cylinders feeds a fuel processing module, which then boosts the pressure to fill the high-pressure storage. The fuel processing modules each contain a PDC Machines booster pump and a refrigeration unit both for cooling the compressed gas and also for chilling the gas prior to the dispenser.

The hydrogen storage system delivers fuel in a cascade operation with the lowest possible pressure tank first delivering fuel to the vehicle. The gas first passes back through the fuel processing module where it is chilled to -40°C and then passes on to the dispenser.

Figure 16: Fuel processing modules at SunLine Transit

1.4.3 STEAM REFORMATION OPPORTUNITY

Steam methane reforming (SMR), or steam reforming, proceeds by the same chemistry that takes place in a MCFC, but with a very important distinction. In the MCFC, the hydrogen produced by the steam reforming reaction is almost immediately consumed by reaction with carbonate ions. That step is what allows the WGS reaction to occur in parallel with SR. In straight SMR, the concentration of produced hydrogen inhibits the WGS reaction. Therefore, WGS is carried out in two separate stages at lower temperatures using two different catalysts. The overall process proceeds as follows:

Steam reforming	$CH_4 + H_2O \rightarrow CO + 3\,H_2$	Ni Catalyst	750 – 900 °C
High temperature shift	$CO + H_2O \rightarrow CO_2 + H_2$	Fe/Cr catalyst	350 – 550 °C
Low temperature shift	$CO + H_2O \rightarrow CO_2 + H_2$	Cu/Zn/Al catalyst	200 – 250 °C

The lower temperatures are needed to obtain favorable thermodynamics that increase the yield of hydrogen. The high temperature shift (HTS) reaction takes advantage of higher rates of reaction but is thermodynamically limited. The low temperature shift (LTS) reaction is slower but favors a high conversion of CO to CO2 and the coincident higher yield of H2. In the LTS process, the CO concentration can potentially fall below 0.5%.

SMR is a tightly integrated process with three separate catalytic reactors. Temperature control is extremely important to prevent runaway reaction while still maintaining a high conversion of reactants into products.

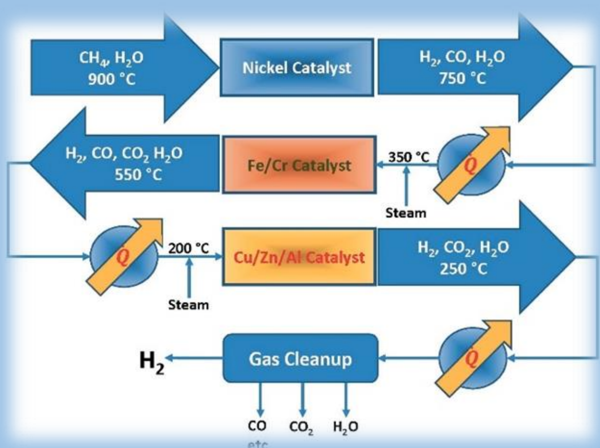

Figure 17: SMR process

Unlike the SR reaction, which is highly endothermic, the WGS reactions are highly exothermic. This requires very careful control over temperature to avoid damaging the catalysts. Part of this is accomplished by the addition of excess steam, and part by external heat transfer.

Finally, careful process control is needed to avoid the highly exothermic methanation reaction:

$$COx + (2 + x)H_2 \rightarrow x\, H_2O + CH_4$$

This reaction is reduced or eliminated through a combination of process control and careful selection of WGS catalyst composition.

Finally, the product gas is then cooled and dried and sent to a pressure swing adsorption (PSA) system to purify the hydrogen to SAE J2719 specification.

Three potential suppliers for on-site production of hydrogen via steam SMR were consulted in the preparation of this report:

- Air Products with their PRISM® Hydrogen Generation (PHG)
- OneH2, who use Nuvera reformers as the basis for their refueling packages
- Linde HYDROPRIME™

One of the key benefits of on-site SMR is that it is generally cost competitive with delivered liquid hydrogen. Both are often the most cost-effective option for demand in the range from about 50 – 10,000 kg/day.

1.4.3.1 AIR PRODUCTS SMR

The Air Products PHG250 package is a single container package that requires 480 V 3-phase power, process water, and a natural gas connection. A single unit would meet the minimum demand requirement for the station with a peak delivery rate of 540 kg/day. The PHG250 equipment is contained in a single 40-foot container.[26] However, this does not include compression, storage and dispensing. A discussion of compression, storage, and dispensing is contained in Section 1.4.4, below.

[26] Kretz, C. Hydrogen, Its Transportation and Markets. Presented at the Renewable Power to Clean Fuels Symposium. Renewable Hydrogen Alliance. Portland, OR. 20 May 2019.

1.4.3.2 ONEH2 SMR

The OneH2 concept is for an SMR unit with associated compression and medium-pressure storage, but this excludes chillers and dispensers. Also, OneH2 is not interested in selling equipment, but rather proposes to own, operate, and maintain the hydrogen production and medium-pressure storage. Hydrogen would be the only thing “sold” to SARTA.

The SMR system consists of gas cleanup (mainly sulfur removal) and compression on the front end, along with water purification for the boiler. The main process unit contains the SMR, water gas shift (WGS) reactors and a boiler. Backend equipment includes preliminary gas treatment to cool the product and remove condensate, followed by a pressure swing absorption (PSA) unit to polish the gas to SAE J2719 standard for refueling hydrogen fuel cell electric vehicles.

One of the distinguishing features of the OneH2 reformer is its turndown capability. The SMR unit is able to operate as low as 50% of design capacity with no loss of efficiency. This means that even while running at partial capacity the production cost of hydrogen remains constant. The SMR unit is capable of turndown to as low as 10% of design, but from 50% to 10% efficiency falls off approximately linearly.

1.4.3.3 LINDE HYDROPRIME

Linde Hydro-Chem division launched the Hydroprime product line of modular on-site hydrogen steam methane reforming units in 2015. These are described as highly integrated units available in standard capacities ranging from 300 (part load) to 56,000 kg/day. Skid mounted modular units are available with capacities up to 2,000 kg/day.

Figure 18: Modular Hydroprime unit

A typical modular Hydroprime unit, such as the one shown here, has a footprint of 14 x 3 m (46 x 10 ft). Natural gas is supplied at 1 barg (14.6. psig), and the delivered hydrogen product is J 2719 compliant at 13.8 barg (200 psig). The system is designed for 98% availability, including scheduled maintenance.

Linde indicated that its skid mounted modular unit can be online within 14 days of delivery on site if proper site preparation is done in advance. The units can be installed either indoors or outdoors, and the open modular design provides accessibility for maintenance and repair.

1.4.4 GAS HANDLING

Regardless the means of hydrogen generation, the gas needs to be compressed, stored, and delivered to a dispenser. Some suppliers, including APCI and Nel Hydrogen prefer to provide the entire system. Others provide only the front half. For OneH2 that means everything up to and including medium-pressure (450 bar) storage; for ITM Power, it means 30 bar hydrogen at the exit of the electrolyzer.

For this part of the system, the CALSTART team contacted Powertech Labs in Surrey, BC. Powertech is the premier test facility in the world for CNG and high-pressure compressed hydrogen vehicle and filling station components. The company offers independent equipment testing and certification services to national and international standards, materials performance assessment, failure analysis, and D/P FMEA for vehicle OEMs. Powertech's quality management system is registered to ISO 9001 which covers all aspects of Powertech's products and services. Powertech is also an accredited laboratory in the Standards Council of Canada Program for the Accreditation of Laboratories.

The system described by Powertech includes the following:

- IRDA communication fills, as per SAE J2601-1 and SAE J2601-2.
- PLC control system, capable of remote access for monitoring, fault clearing, and data file downloads (internet connection required).
- Flow measurement, accurate to ±5% at 1 kg hydrogen dispensed.
- Documentation, including manufacturers' manuals where applicable, and drawing package and operations manuals in PDF format.
- Containerized package with compressor, pre-cooling and controls.
- Two 350 bar, stand-alone, dual-hose dispensers, including user interface.
- One 700 bar, stand-along, single-hose dispenser, including user interface.
- Hydrogen cooling system for 700 bar, T40 fills.
- Perform H70 T40 fills to 95% SOC or greater, with starting vehicle pressure of 50 bar, as defined by SAE J2601-1.
- Five back-to-back 700 bar fills (95% SOC) of a 12-kg hydrogen tank starting at 100 bar with three minutes between each fill.
- Perform H35 ambient fills to 95% SOC or greater, with starting vehicle pressure of 50 bar, as defined by SAE J2601-2. Option pricing is available for pre-cooled H35 fills.
- Four simultaneous 350 bar fills of 35-kg hydrogen tanks starting at 100 bar.
- 180 kg hydrogen storage at 875 bar.
- 700 kg of hydrogen storage at 450 bar to accommodate simultaneous bus fueling.
- Two compressors capable of compressing hydrogen with the following specifications:
  -Min suction pressure of 54 bar (800 psig)
  -Max output pressure of 442 bar (6,500 psig)
  -10.1 kg/hr (per compressor) at 52 bar (800 psig) suction pressure
- One compressor capable of compressing hydrogen with the following specifications:
  -Min suction pressure of 136 bar (2,000 psig)
  -Max output pressure of 1,000 bar (15,000 psig)
  -8.9 kg/hr at 200 bar (3,000 psig) suction and 828 bar (12,200 psig discharge)

Figure 19: Powertech fuel processing module and high-pressure storage at the Riverside hydrogen refueling station. Image Credit: Hydrogen Ventures.

Not all of these items track exactly with the station configuration as currently envisioned because there has been some redirection since Powertech was originally contacted. Still this provides a good sense of how the station could be configured, with some sense of scale and cost. To the extent possible, equipment will be preassembled and tested prior to shipment from Powertech.

For the H70 fill option Powertech proposes a custom designed enclosure that will contain the compression and refrigeration equipment as well as all control. The enclosure is expected to measure about 12 x 40 feet and will be designed for ease of installation and transport. The station would be designed for outdoor installation in Canton, OH.

The Powertech proposal includes two medium-pressure compressors capable of compressing 485 kg/day H2 to 450 bar for H35 refueling. Part of that will be tapped for the higher-pressure storage at 875 bar. If the decision is made to increase the station capacity to closer to 1000 kg/day, the capacity or size of the compressors would need to be revisited.

The medium-pressure storage and dispensers are designed to be able to provide four simultaneous 35 kg fills and will be able to dispense a minimum of 420 kg over a 24-hour period.

Approximate size of major components is as follows:

- 450 bar Container Module 30 ft (L) x 12 ft (W) x 8 ft (H) – Includes two compressors, refrigeration unit and electrical / control cabinets.
- 875 bar Container Module 35 ft (L) x 12 ft (W) x 8 ft (H) – Includes one compressor, refrigeration unit and electrical / control cabinets.

- 500 bar Storage 40 ft (L) x 10 ft (W) x 10 ft (H) – Includes 700 kg of 450 bar hydrogen storage.
- 900 bar Storage 10 ft (L) x 10 ft (W) x 8 ft (H) – Includes 180 kg of 875 bar hydrogen storage.
- 700 bar Dispenser 10 ft (H) x 2 ft (D) x 4 ft (W) – Includes single nozzle 700 bar dispenser with integrated hydrogen pre-coolers.
- 350 bar Dispensers (qty 2) 10 ft (H) x 2 ft (D) x 4 ft (W) – Includes dual-nozzle 350 bar dispenser.

The approximate cost for the system as presented here is about $4 million. There are also two options being offered. One is a precooling system for 350 bar fills that would be about $150k, and addition of a third medium-pressure compressor for about $250k.

Powertech estimates that equipment delivery would be 48 – 52 weeks after receipt of order.

2. H2 STORAGE EVALUATION

2.1 SIZE OF HYDROGEN STORAGE FACILITY

One of the defining features of the current SARTA facility is that the refueling of all vehicles occurs in a relatively short time interval. Buses may start refueling as early at 9:45 p.m. and the process is generally complete well before 2 a.m. This is distinctly different than retail hydrogen stations in California, where cars show up randomly throughout the day, with three peak demand periods occurring around 8 a.m., and 12 and 5 p.m.

Hydrogen vehicles are filled with a cascade fueling system. In cascade fueling there are generally three or more "banks" of tanks designated high, medium, and low pressure. When the refueling nozzle is connected to the vehicle the dispenser senses the fuel tank pressure and then begins fueling from the bank with the lowest possible pressure. Switching between banks occurs when the pressure differential falls below a set value – often between 27 and 41 bar (400 – 600 psi), depending on the equipment vendor.

Cascade fueling allows the station high pressure compressor to be sized significantly smaller than would be needed to maintain a constant high pressure in the ground storage tanks.

What this will mean for the expanded SARTA facility is that the amount of stored hydrogen will need to be well in excess of the amount needed for just a few vehicles per hour spread out across an entire day. General guidance for this scenario coming from existing retail station operators as well as auto manufacturers is to have 2 – 3 times as much storage as the vehicles will need. The reasons for this vary. Obviously, there is the issue that in a cascade fueling system, there still needs to be at least one tank to draw from with a pressure greater than the final fill pressure of the last vehicle to be filled, but other issues factor in as well.

Timing is one such factor. If, for whatever reason, it becomes necessary or desirable to begin filling before all of the storage is pressurized, the latter vehicles may be delayed while waiting for additional hydrogen to be produced. This could happen as a result of an unavoidable change in deployment schedule. It could also result from any number of issues that slow or stop hydrogen production on site. Examples could be failure of a compressor or a chiller going offline. Even if these issues can be resolved in a timely fashion there could be disruption to the bus schedule which could be avoided by simply expanding the capacity of what ultimately is one of the least costly unit operations in the entire station.

This means that for H70 vehicles with a cumulative demand of 60 kg there should be 120 – 180 kg capacity in 95 MPa tanks. Typical single-dispenser H70 stations in California have 180 - 200 kg storage capacity and can dispense about 133 kg on a single hydrogen delivery. This has been found to be marginal for providing reliable hydrogen refueling, leading frequently to vehicles receiving only a partial fill. Similarly, to fill 12 buses and 5 PFCV with a total demand of 480 kg in fast-fill mode, at least 960 kg storage will be needed. This is eight times the current storage capacity of 120 kg being used for slow fill of the existing buses. Although the station can dispense 65–75% of storage capacity, the additional storage is needed to provide margin in the event of production equipment going offline.

In planning for future possible expansion of station operations, provisions should be incorporated to permit simple doubling of storage capacity to 360 kg for H70 and 2,000 kg for H35.

The current 11 fuel cell electric buses (FCEBs) are refueled from a liquid hydrogen tank that stores roughly 2,400 kg. Hydrogen fills are accomplished with fueling station dispensing units along with its hydrogen compression and storage technologies. The station is designed to fuel up to 20 FCEBs but was built to allow upgrades for expansion. The station includes two compressors to reduce the chance of downtime. The hydrogen storage equipment and compressors are leased along with operations, and maintenance. The dispenser provides hydrogen at 350 bar pressure for the FCEBs and is in the fueling island that is part of a public access CNG station at the front of the property. The transit agency plans to add a dispenser for light-duty FCEVs at 700 bar pressure.

The two compressors are capable of compressing 120 kg/h LH2, and so have plenty of capacity for the expanded station. It is envisioned that the 700 bar dispenser will have storage filled from the lower pressure tanks, or better yet, from a dedicated bank of the lower pressure tanks. That will reduce requirements for both size and capacity of the high-pressure compressor.

Fueling a bus takes about 20 minutes. The agency uses a lower fueling rate to avoid the need to top off the tanks before putting the FCEBs into service in the morning. The final settled pressure and ambient temperature readings are recorded at 4:30 a.m. after the gas temperature has cooled and before service. A lookup table is used to determine the mass before fueling and after settling and then subtracts the initial mass from the final mass to calculate the kilograms dispensed.

It is desired that any new capacity installed will provide fast fill of the buses. However, the existing buses were designed with receptacles based on an older J2600 standard and may not be upgradeable to the new standard. This may necessitate retaining at least one of the existing dispensers for filling of the legacy buses or accepting a non-comm (no IR communication link) slow fill from the fast fill dispensers.

2.2 HYDROGEN STORAGE STRATEGIES (BELOW GROUND, ABOVE GROUND).

On the question of above- versus below-ground storage, the consensus seems to be that in most cases above ground is preferred. The reasons are many. Safety is a major consideration. If a simple vault is used for below-ground storage, the area above the vault isn't necessarily freed up. Any equipment over the vault still needs to meet relevant safety regulations such as class 1 div 2. If the space over the vault needs to be freed up for vehicle traffic, then the vault construction starts to get quite expensive. One comment received was that *you don't want to have anything pressurized underneath you for simple reasons of safety*.

Another issue is excavation. This is definitely a concern if the land is leased but should always be a consideration. If at some point the station is dismantled due to obsolescence (or the lease expires), not only the tanks, but the vault also needs to be removed and disposed of. It's one thing to remove the shallow vaults used for piping and utilities, but a vault large enough to house 800 – 1000 kg hydrogen, plus associated utilities, is going to be a major undertaking, as will be the engineering needed to design the backfill.

Subjects interviewed could not point to any specific parts of NFPA or ASME standards dealing specifically with underground hydrogen storage, but they did suggest some issues that might need to be addressed. These include forced air positive ventilation, sealed class 1 div 2 sump pump motors, drainage, isolation valves both inside and outside the vaults, space for both routine and unplanned maintenance, as well as regular inspections (the high-pressure tanks at Cal State LA, as of November 2019, are scheduled for x-ray inspection).

Finally, tanks operating at pressures greater than 680 bar (10,000 psig) have a limited lifetime as dictated by the manufacturer. These tanks can tolerate only a limited number of pressure cycles before replacement is indicated.

This means that replacement could be a rather expensive task unless some means of egress is designed into the vault.

Other reasons for keeping the storage above ground are for ease of maintenance and inspection. Hydrogen does leak, and sometimes the leaks are spurious (and unimportant). A spurious leak in an open-air environment might get past the leak detectors, but inside a vault it could result in an unnecessary station shutdown and require someone to climb into the vault. This was a constant problem with hydrogen dispensers as recently as just a few years ago. Valves and fittings were not as robust as they are now, and the majority of station shutdowns resulted from leaks that had disappeared by the time maintenance showed up.

All this being said, both Linde and BOC Gases are reported to have developed extensive IP surrounding vault storage of high-pressure hydrogen, and both Air Products and Nikola are considering it for future installations.

An interesting suggestion from OneH2 was that if space is absolutely at a premium, consider doing away with medium-pressure storage and go with all high-pressure storage using 1,000 bar type 1 cylinders.

Another concept to consider if the footprint is absolutely an issue is canopy storage. The original Shell Hydrogen station in Santa Monica had the electrolyzer, compressors, and storage all on top of the station canopy. The reasons this hasn't been used more for the California Hydrogen Highway stations has been because the type II cylinders are heavy and California is seismically active, necessitating significant structural reinforcement. Note the photo of the Shell Hydrogen station.

Figure 20: Shell Hydrogen station on Santa Monica Blvd in Santa Monica, CA

Canton, Ohio, though, has very low seismic risk. In addition, suppliers such as Hexagon Lincoln are now offering low-mass 950 bar type IV hydrogen cylinders. This may be an option worth consideration if there is a need to maintain free space around the refueling islands and maintenance yard.

2.3 DETERMINE POSSIBLE ROLE IN GRID

There are multiple roles that the hydrogen station can play in the local microgrid concept. Some of these are being considered in detail in a separate study under this program. However, it is worthwhile to address some of these broader concepts here within the context of the different technologies presented in the earlier sections. Note that the different scenarios presented here are not necessarily independent of one another and could be combined to produce a more comprehensive solution.

2.3.1 HYDROGEN AS SHORT-TERM BACKUP POWER STORAGE

In this scenario, the hydrogen station would be dependent on the microgrid for power but would produce and store excess hydrogen that would be available to produce power through a fuel cell should the microgrid experience either planned or unplanned shut down. The microgrid in this case could be conventional power generation, such as small turbine or reciprocating engine gensets. The microgrid power could also come in part or in entirety from solar photovoltaic power generation. In the case of on-site electrolysis this would require a utility-scale PV system as described earlier.

2.3.2 HYDROGEN GENERATION AND MICROGRID AS CODEPENDENT RNG USERS

In this scenario hydrogen is produced from RNG either through tri-generation or SMR. In either case the microgrid and hydrogen generation would share a pipeline feed of RNG. In the case of tri-generation, the tri-generation unit would be the main power supply for the microgrid, as well as producing more than enough hydrogen for planned and future station operation. In the SMR case, the shared RNG would fuel a conventional genset, which would provide power for both the microgrid and on-site hydrogen generation, storage, and dispensing.

3. FINANCING STRATEGIES EVALUATION

SARTA is the public transit authority for Stark County, Ohio. During 2018, SARTA served more than 6,500 riders covering 7,500 miles per average day.

Most of SARTA's operating expenses are paid for through a 0.25% county sales tax levy. The remainder comes through revenue service and Federal grants. According to SARTA's financial statement for 2018,[27] operating expenses were $23.8 million with total revenues of $21 million. Passenger fares accounted for only $1.36 million of total revenues. Also, during FY18, SARTA had numerous capital projects in progress. These had total budgets of $26.6 million, with Federal grants and other funding vehicles covering $21.4 million of that. This includes $1.76 million for acquisition of fuel cell paratransit vehicles and $4.3 million for fuel cell buses. In 2016, SARTA's 0.25% sales tax levy was renewed through June 2027 by voter approval.

Upgrading the hydrogen refueling station is a major capital improvement. Depending on the approach taken, it could run $6 - $9 million for the H35 upgrades and $1 -$2 million for the H70 installation. Installation of solar photovoltaic power sufficient to provide for electrolysis would add another $20 - $30 million. This section deals with potential funding/financing avenues available to SARTA to cover those costs.

Much of the discussion in this section is based on the review paper by Chen and Bartle (2017)[28] unless stated otherwise in the footnotes. It is recommended that the reader refer to this document for additional detail and references.

3.1 DEBT FINANCING

Debt financing is often used for infrastructure projects because these often involve large or lumpy investments and benefit both current taxpayers and future generations. *The use of debt financing is justified in part by the rationale of spreading out the costs of public infrastructure investments throughout the life of the asset.*

The main types of debt financing for local governments are private bank financing, infrastructure investment funds, and bonds. Other approaches include environmental state revolving funds, state infrastructure banks, and grant anticipation revenue vehicle bonds. Of the latter three, only the State Infrastructure Bank (SIB) would seem pertinent to the current project. This section discusses these options.

3.1.1 PRIVATE BANK

Private bank financing is reportedly the most common type of financing used by local government agencies for major infrastructure development. Though this may be used mostly for multidecade projects like libraries, schools, and public works, it can also be used for transportation projects like public transit.

[27] Stark Area Regional Transit Authority Comprehensive Annual Financial Report for the year ended December 31, 2018.

[28] Chen, C. and Bartle, J.R. Infrastructure Financing: A Guide for Local Government Managers. A Policy Issue White Paper for ICMA (international City/County Management Association) and GFOA (Government Finance Officers Association) January 2017.

3.1.2 STATE INFRASTRUCTURE BANK

The Ohio Department of Transportation administers the Ohio State Infrastructure Bank. The Ohio SIB was started with $40 million from state general revenue funds, $10 million in motor fuel taxes, and $87 million in Federal Title XXIII highway funds. The program provides for low interest loans for revenue generation projects, including transit facilities and projects. As such, it is expected that the loan will be repaid using revenue generated from the project. Determination of eligibility under *e.g.* 23 U.S.C. 503/508/513 would need to be assessed prior to applying under SIB.

3.1.3 INFRASTRUCTURE INVESTMENT FUNDS

Chen and Bartle (2017) define an infrastructure investment fund as follows:

An infrastructure investment fund generally refers to an entity in which large investors—such as pension funds, sovereign wealth funds, private insurance companies, and investment banks—pool their financial resources and employ experienced fund managers to invest their fund equity into various kinds of infrastructure assets.

The principal advantage of infrastructure investment funds (IIFs) is quick access to capital. This is at least partially offset by increased project financing costs.

Chen and Bartle cite as an example the Dallas Texas Police and Fire Pension System (DPFP). As of yearend 2015, the DPFP had 6.7% of their portfolio invested in infrastructure projects. In FY2017, however, it reported that it had sold off a significant portion of that and ended the year below its minimum allocation range for this asset class level.[29]

3.1.4 BONDS

SARTA has stated in its 2018 CAFR: *"The Authority has no long-term debt, nor does it have any plans to acquire long-term debt in the immediate future."* However, issuance of short term (*e.g.* five years or less) bonds might be explored as one possible avenue for financing some or all of the hydrogen station expansion at SARTA.

3.1.4.1 GENERAL OBLIGATION BONDS

General obligation bonds tend to be issued for long term projects and are serviced by general tax revenues. These could be issued and paid for via an increase in the sales tax increment currently levied by SARTA. This would require voter approval. However, in this case, as mentioned later, the debt service would likely be at most a couple of years since even a small increase in the sales tax levy could generate nearly $20 million per year.

[29] Dallas Police & Fire Pension System Comprehensive Annual Financial Report for the Years Ended December 31, 2017 and 2016

3.1.4.2 REVENUE BONDS

Revenue bonds are an unlikely vehicle for financing station upgrades but are included here for completeness. Revenue bonds would be serviced by an increase in fares. However, at first glance it seems that such an increase would require nearly doubling the fare in order to achieve a payoff within the lifetime of the new assets.

3.1.4.3 GREEN BONDS

Green bonds are regular bonds but are issued to finance specific projects with significant environmental benefits. The first green municipal bond was issued by the state of Massachusetts in 2013. Later that same year, the city of Gothenburg, Sweden became the first municipality to issue a green bond. The latest updated 2016 Green Bond Principles provide broad categories for suitable green activities (International Capital Market Association 2016):

- Renewable energy
- Energy efficiency
- Pollution prevention and control
- Sustainable management of living natural resources
- Terrestrial and aquatic biodiversity conservation
- Clean transportation
- Sustainable water management
- Climate change adaption
- Eco-efficient products, production technologies, and processes.

As can be seen, the first three and the sixth categories on this list are applicable to the expansion of the SARTA fuel cell bus program to include renewable hydrogen as a transportation fuel.

There are several references that should be consulted before considering issuance of green bonds to finance the SARTA expansion.[30]

3.2 TAXATION

Any time a public agency incurs debt, it is necessary to service that debt through payment of principal and interest to the investors. Taxation is the usual method for servicing that debt.

3.2.1 SALES TAX INCREASE

Under Ohio state law, SARTA is able to levy sales tax at 0.25%, 0.5%, 1% or 1.5% within Stark County *subject to voter approval*. As mentioned earlier, that tax is currently set at 0.25% and is approved through 2027.

The amount of revenue SARTA realizes through the current 0.25% sales tax levy is large enough that, depending on the project size, an additional 0.25% sales tax would likely pay off any bond or loan obligation in one or two

[30] *See:* GFOA White Paper: Green Bonds. Government Finance Officers Association October 1, 2015; Green Bond Principles: Voluntary Process Guidelines for Issuing Green Bonds. International Capital Market Association. June 2018; and https://www.climatebonds.net/.

years. However, the rate increase would need to be approved by a majority of Stark County voters, and it isn't clear that the voters would support such an increase for the proposed project.

Another form of sales tax increase that has been mentioned is a special tax on parking. Specifically, this would be a charge on paid parking, whether public or private. It is unclear whether this would be allowable under SARTA's current charter. It is also not clear how much revenue could be generated through this approach, and whether this would be a flat fee per event or a percentage of total sales of parking. In all likelihood, this would require a separate study and independent evaluation to determine feasibility.

3.2.2 GENERAL TAXES

General taxes are likely not an option for SARTA without approval at the state level.

3.2.3 SPECIAL ASSESSMENT DISTRICT (TRANSPORTATION DEVELOPMENT DISTRICT)

A transportation development district (TDD) is an example of a special dedicated tax that includes a geographic area (Stark County) in which property owners or business owners agree to pay a special tax assessment to fund an improvement or service from which they stand to benefit. This can often be done without the requirement of voter approval. However, it might require legislative approval. A major appeal of this approach is that it can directly match payments with benefits.

3.3 USER CHARGES

In this context, user charges would amount to an increase in transit fares. This increase can be used as the dedicated revenue source to secure bonds at a rate lower than might otherwise be possible. Currently, though, revenue service accounts for only about 10% of SARTA's operating cost. This means that any reasonably acceptable increase in fares would result in a bond lifetime greater than the life of the refueling assets.

Other user charges, such as the South Coast Air Quality Management District's $1 per year automobile registration fee, are generally not permitted in Ohio under Article XII, Section 5a of the Ohio Constitution.[31]

3.4 CAPITAL RESERVES

As of 31 December 2018, SARTA reported $11.5 million in cash and cash equivalents on hand. While it is important to maintain a healthy margin of capital reserves in the event of hardship, such as a downturn in revenues (as may occur in 2020 due to the COVID-19 outbreak), they can also be used to reduce debt obligations or to make up for unanticipated costs. In this context, capital reserves might serve as a cushion against a gap between state and federal grants and the actual end cost of the project.

[31] Jackson, V and Patton, W. How Ohio Funds Public Transit. Policy Matters Ohio, May 2017.

3.5 FEDERAL GRANTS

In 2018, SARTA received about $6.4 million per year in Federal grants. $3.8 million of this is for capital expenses. The remainder falls under operating grants. In 2016, Federal capital and operating grants totaled $20.4 million.

This would seem to make Federal grants a promising avenue for financing the planned station upgrades. However, FTA dollars come with restrictions that could reduce competition and increase the costs of the upgrade. Further, recent proposed cuts in FTA budget and spending suggest that caution should be exercised, and alternatives should be carefully considered.

3.5.1 5339(C) LOW-NO GRANT (LOW OR NO EMISSION COMPETITIVE PROGRAM)

From the FTA website:

The Low or No Emission Competitive program provides funding to state and local governmental authorities for the purchase or lease of zero-emission and low-emission transit buses as well as acquisition, construction, and leasing of required supporting facilities. Under the FAST Act, $55 million per year is available until fiscal year 2020.

This program will pay up to 90% of the net project cost for leasing or acquiring low- or no-emission bus-related equipment. It will pay up to 80% of the net capital project cost. The Federal share may exceed 80% for certain projects related to the ADA, the Clean Air Act (CAA), and certain bicycle projects.

According to FTA, they will release a Low-No NOFO for fiscal year 2020 within 30 days of receiving full year funding.[32]

3.5.2 BUILD TRANSPORTATION GRANTS PROGRAM

The FY2019 notice of funding opportunity for BUILD was posted in the Federal Register on April 23, 2019 with applications due on July 15, 2019. Under this program, the Federal government will pay up to 80% of a project located in an urban area. The minimum grant size is $5 million, and the maximum is $25 million.

The BUILD program is focused on surface transportation capital projects. Research, demonstration, or pilot projects are eligible only if they will result in long-term, permanent surface transportation infrastructure that has independent utility.

For 2019, $870 million in BUILD funds were awarded to 55 projects.[33] Of these 31 were rural. Fourteen project awards were at or near 80% of the total program cost. Twenty-five of the projects were heavily leveraged, with BUILD funds representing 50% or less of the total project cost.

According to the BUILD website:

The program selection criteria encompassed safety, economic competitiveness, quality of life, state of good repair, ***environmental sustainability****, innovation, and partnerships with a broad range of stakeholders.*

[32] Personal communication: Tara Clark, FTA (tara.clark@dot.gov). 11/25/2019.

[33] https://www.transportation.gov/sites/dot.gov/files/docs/subdoc/906/build-fact-sheet2019.pdf

(emphasis added).

In fact, though, only one project in 2019 involved zero-emission transportation: the GROWLIFE project in Lancaster, CA.

3.5.3 U.S. DOE STATE ENERGY PROGRAM GRANTS

State Energy Program (SEP) grants are issued through the Ohio Development Services Agency. This is a generally small pool of funds but could be applicable to certain aspects of the station upgrade. These might include installation of solar photovoltaic power generation, establishment of the microgrid (*e.g.* switchgear), or installation of the pipeline for delivery of RNG to an SMR or tri-generation unit. If hydrogen storage is integrated into a microgrid concept, the hydrogen storage and fuel cell might also be considered eligible projects under SEP.

3.6 STATE GRANTS

3.6.1 OTPP SFY 2021

Ohio Transit Partnership Program (OTP2) funds for 2020 have already been awarded. However, 2021 program applications are expected to be due in September 2020.[34] According to Chuck Dyer of ODOT,[35] the program is closely based on the previous OTPPP (or OTP3). Under tier I OTP2 can provide matching funds for several Federal programs, including 5307, 5311, 5337, and 5339. Tier II is a bit more flexible and is probably most applicable to the hydrogen station expansion as it provides funding for clean fuels and fueling infrastructure.

At this point, however, the program details have not yet been posted to the ODOT website.

3.7 PRIVATE-PUBLIC PARTNERSHIPS (P3)

3.7.1 DESIGN-BUILD-OPERATE-MAINTAIN

Under this model, SARTA is still responsible for financing the installation but shifts the risks of operating costs and project revenues to the developer.

[34] Dyer, C. and Hostin, J. FY2020 OTP2, Ohio Department of Transportation, August 27, 2019.
[35] Personal Communication: Chuck Dyer, ODOT November 20, 2019.

3.7.2 DESIGN-BUILD-FINANCE-OPERATE-MAINTAIN

Design-Build-Finance-Operate-Maintain (DBFOM) turns the entire project over to the developer. SARTA would host the project on its premises in the case of electrolysis or SMR and would also be responsible for utility costs. This leads to a take-or-pay contract where SARTA is at risk if multiple vehicles are out of service, or if service needs to be suspended due to acts of god. However, at the same time the owner/operator is potentially at risk in the case of equipment failure because they are guaranteeing to deliver a product at a certain time at a specified cost.

This is essentially what OneH2 is proposing, and what APCI describes on its web site. OneH2 has submitted a proposal and specifications (provided as a separate confidential document to SARTA) for a system intended to meet the minimum requirements (there was some miscommunications within OneH2 leading to the specification being slightly off from the maximum H2 production rate). In its proposal it essentially offers:

- $8.00/kg for the first 150 kg/day
- $7.50/kg for 151 – 300 kg/day
- $7.00/kg for 301 – 450 kg/day

In this proposal, OneH2 owns and maintains the production, compression, and storage equipment, and SARTA is responsible for the dispensers and chillers. In addition, SARTA is responsible for paying all utilities (electricity, water, natural gas).

One additional note on the OneH2 proposal: the system it proposes also produces up to 375 lb/h saturated steam at 240 psig, which has not been figured into the value proposition of the project. Assuming 8,400 hours per year, the value of this byproduct could be worth around $30k annually, depending upon whether SARTA could use the steam in its operations.

In a conversation with Brian Bonner at APCI,[36] he said that APCI is agnostic with regard to the hydrogen production technology and would prefer that APCI simply pass the hydrogen "over the fence." This would be the same whether SMR or electrolysis were the chosen direction. The source of renewable feedstock would be at the discretion of SARTA, and who actually pays for utilities (natural gas and/or electricity plus water and sewer) would be a matter for negotiation during the contract phase of the project.

PermaCity also described a DBFOM approach it would like to pursue with SARTA for a utility scale solar PV installation similar to Westmont (described earlier). Based on conversations with Jonathan Port (CEO PermaCity), in the 2017 timeframe, the Westmont project entailed the following:

- Investor financing arranged by PermaCity through True Green Capital[37]
- All building roofs replace with vinyl roofing for long life and reduced albedo
- Utility substation with grid interconnect
- Roof leasing arrangement with building owners

> Note: *The Government Finance Officers Association (GFOA) advises that local government agencies exercise caution when approaching public private partnerships. GFOA has issued guidance for approaching P3 agreements in such a way as to mitigate risk and help ensure long term financial success of the agreement.*
>
> https://www.gfoa.org/public-private-partnerships-p3
>
> https://www.gfoa.org/establishing-public-private-partnership-p3-agreements-outsourcing

[36] Brian Bonner, Air Products and Chemicals, Inc. Personal communication 4 December 2019.
[37] https://truegreencapital.com/investment-case-study/westmont-portfolio/

- All maintenance, including roofs for 20 years
- 20-year PPA with Los Angeles Department of Water and Power
- 50-year expected life of all power generation infrastructure

The solar installation described earlier in this report would be just sufficient for the electrolyzer concept of station upgrade. To extend the system to include the microgrid, a marginally larger solar installation would be required. Also, this would not eliminate the need to identify financing for the actual station upgrades.

4. MAJOR FINDINGS

EQUIPMENT FOOTPRINT

In rank order, tri-generation has by far the largest footprint and steam methane reforming the smallest amongst on-site generation options.

Tri-Gen MCFC >> Electrolysis > Steam Methane Reforming > Delivered Liquid

A representative for FuelCell Energy provided a figure of 20,000 square feet for tri-generation. The ranges for electrolysis and steam methane reforming were estimated from various public sources. The electrolysis footprint ranged from 2,300 square feet for a containerized solution to as much as 7,500 square feet for an open plant layout. Steam methane reformer packages ranged from 1,600 to 1,750 square feet, including compression and storage.

INSTALLED COST

In terms of installed cost, tri-generation is the most expensive and steam methane reforming the least expensive on-site option.

Tri-Gen MCFC >> Electrolysis > Steam Methane Reforming > Delivered Liquid

A tri-generation system is estimated to cost $25 – 30 million. Electrolysis system costs, including compression and storage, were estimated to range from about $4.5 to more than $9 million. Costs for steam reforming systems were not provided but both station operators and electrolysis system providers stated that reformer system costs were significantly lower than for electrolysis.

COST OF PRODUCED HYDROGEN

The cost of produced hydrogen is highly dependent on utility costs. Furthermore, in the case of tri-generation, it is also dependent on the value of the electricity cogenerated with the hydrogen. However, in general it appears that costs are ranked as follows.

Tri-Gen MCFC > Electrolysis > Steam Methane Reforming ~ Delivered Liquid

For tri-generation, FuelCell Energy stated that production costs are between $5 and $10 per kg. Factoring in straight line depreciation of the equipment over its lifetime adds another $10 per kg. For electrolysis, equipment is about $3 per kg and operating costs another $3-$6 per kg. No reliable production costs for steam methane reforming were found. However, OneH2 believes they can make a profit selling on-site hydrogen for as little as $7 per kg, and Air Products literature states that on-site reforming is often more attractive than delivered liquid.

RENEWABLES

The following renewable options were examined:

- Solar Photovoltaic Electricity
- Wind Electricity
- Renewable Natural Gas

All three were found to be viable options for the SARTA upgrade. For 2018, solar PV was about $30/MWh, and wind PPAs averaged less than $20/MWh. Natural gas generation was slightly higher at just under $40/MWh-equivalent (calculated at a heat rate of 7.5 MMBtu/MWh).[38] In contrast, renewable natural gas alone was cited by Waste Management as costing about $15/therm plus delivery. While solar PV is competitive over time, though with a long payback period, wind electricity appears to be competitive with other retail generation. Renewable natural gas is quite expensive relative to pipeline natural gas but may become more competitive down the road if fossil natural gas prices start to rise. Both renewable natural gas and wind power would be delivered by the utility indirectly, by displacement, and as a result would not eliminate distribution costs and riders.

FINANCING OPTIONS

Most of the financing options identified involve taking on debt. Debt service would require an increase in revenue, which could be done by raising taxes (with voter approval) or by increasing fares.

There are, however, grant opportunities at both the state and Federal level that could pay for a significant share of the expansion project. The number of specific programs is fewer than in recent years, however, and the total amount of available funding appears to have been reduced.

[38] Timmer, J. *Wind Power Prices Now Lower than the Cost of Natural Gas*. ARS Technica. 8/17/2019. https://arstechnica.com/science/2019/08/wind-power-prices-now-lower-than-the-cost-of-natural-gas/.