Economics of Carbon Capture and Storage for Small Scale Hydrogen Generation for Transit Refueling Stations

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Cover Photo: Hydrogen Fuel Cell Zero Emission Bus and Refueling Station, Stark Regional Transit Authority, Canton, Ohio

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Executive Summary

Refueling infrastructure for early adopters of hydrogen vehicles finally appears to be imminent. There is a consensus among long haul trucking and transit agencies that hydrogen fuel cell electric vehicles are likely to be the most cost-effective strategy for transitioning to low or zero emission fuels, especially in cold weather climates. Hydrogen refueling stations will require careful planning to ensure costs are low and that carbon dioxide emissions are minimized. Until such time that refueling stations are commonplace, the most likely scenario for mitigating both costs and carbon intensity will be local, on site hydrogen generation at the refueling stations.

This study was undertaken on behalf of Stark Area Regional Transit Authority (SARTA), which currently has a hydrogen refueling station on its campus in Canton, Ohio, to support a fleet of hydrogen fuel cell buses and paratransit vehicles (17 by 2021). The refueling facility is expected to require 500 kg/day of hydrogen to maintain this fleet, and could grow higher depending upon future fleet replacement. Currently, SARTA has liquid hydrogen delivered by truck from a large steam methane reformer in Ontario, Canada. The life cycle carbon dioxide emissions, while significantly lower than that from burning diesel, is relatively high from this strategy. SARTA seeks to identify, and if practicable, implement lower carbon emission strategies. Accordingly, SARTA commissioned this study through the Renewable Hydrogen Fuel Cell Collaborative to examine alternative scenarios to mitigate carbon emissions from hydrogen delivery.

There are several carbon mitigation strategies available for local generation at SARTA. This study examined three such strategies: electrolysis of water, steam reformation of renewable natural gas, and steam reformation of traditional natural gas (commonly referred to as “Blue Hydrogen”). The cost and carbon intensity of these strategies were compared to the incumbent strategy of making hydrogen at large scale plants, which hydrogen is then liquified and trucked to SARTA’s facility.

An analysis of the state of current technologies suggests that on site blue hydrogen generation can be competitive with the incumbent strategy, while significantly reducing carbon dioxide emissions, if a local market can be found to use the carbon dioxide. At least two such markets appear to be available in the Canton, Ohio area: enhanced oil recovery for the East Canton Oil Field, and ready-mix concrete supply companies. Both methods not only use the carbon dioxide, but also sequester it. The enhanced oil recovery strategy is particularly attractive, insofar as it promises to spur local economic activity by making otherwise marginal production profitable.

The following table compares different projected costs and carbon intensity of several strategies, including blue hydrogen. Costs were estimated using U.S. National Laboratory cost calculators, and carbon intensity was determined empirically, based upon prior work by the research team and/or industry literature. The estimated costs are also in keeping with proposals that CALSTART received in a feasibility study SARTA commissioned in the spring of 2020.

Comparison of Cost and Carbon Intensity for Various Small-Scale Hydrogen Production Options.

Method	Cost ($/kg H_2)	Carbon Intensity ($kgCO_2e/kg\ H_2$)
SMR: delivered via LH_2[a]	5.93	9.81[b]
SMR: onsite, no capture	3.22	8.98
SMR: RNG, no capture	4.49	2.22 – 5.32[c]
SMR: onsite with capture (blue)		
- with geological storage	3.65	2.44
- with EOR/ECOF	3.52	4.17
- with EOR/MCOF	3.47	4.40
- with RMC	3.27	2.44
Electrolysis (green) – no grid	7.43	2.58

[a] This hydrogen is compressed and liquified in Sarnia, Ontario, Canada, and delivered ca. 270 miles in LH_2 tanker trailers to SARTA. *Importantly, this method of delivery arrives under pressure, and little or no additional on-site hydrogen compression is required for storage. This cost needs to be accounted for in a true apples to apples comparison.*

[b] The incremental carbon footprint assumes negligible boil-off losses at the Sarnia trailer refill and during transit, and emissions of 220 gCO_2e/tonne/mile due to fuel consumption.

[c] The lower bound represents WWTP RNG at 19.34 gCO_2e/MJ and the upper bound represents landfill RNG at 46.42 gCO_2e/MJ.

A true apples to apples comparison will require some site specific planning and engineering, and possibly a Request for Information. For instance, onsite blue hydrogen requires an estimated additional cost of around $0.75/kg to pressurize the incoming natural gas, and another $1.50 to pressurize the they hydrogen for storage. The status quo strategy – trucked hydrogen – arrives as a liquid, and eliminates those costs. Similarly, electrolysis requires no natural gas pressure, and also promises to produce hydrogen at a higher pressure, thereby reducing compression costs. Likewise, it is possible that SARTA could get electricity on site for a lower cost than estimated in this study (which assumes solar plus batteries in order to have no coal component). ***The result is that the total "all in" cost of the various strategies may end up being comparable – in the $6-8/kg range – when actual designs are prepared and proposals are received.***

It is also important to note that currently carbon costs are totally externalized. This is not likely to continue, as climate change is upon us. An international consensus is likely to cause the United States to soon implement a strategy to put a cost on carbon emissions. Carbon intensity of the various strategies likewise may also vary depending upon the final design. This study suggest that estimated carbon emissions will be comparable from blue and green hydrogen strategies. However blue hydrogen requires that SARTA establish a carbon market, which will be uncertain until outreach to those markets is undertaken. Most likely, SARTA would have to retrofit a carbon capture system to its SMR plant after those markets are established. Alternatively, SARTA could at any time switch to renewable natural gas, which could be delivered at any time by displacement.

The decision to choose the path of blue or green hydrogen will inevitably incur risk. These risks include, among others, changing power and natural gas prices, uncertainty of carbon markets, and use of new technologies that may have no established a track record. The largest uncertainty is the continued ability to internalize carbon emission costs. These will all have to be weighed as part of SARTA's planning to continue its leadership in developing and maintaining a zero-emission fleet.

SARTA, with its anticipated fleet of 17 regular and paratransit buses, appears to have a large enough hydrogen load to be able to cost effectively generate hydrogen on site at least through steam methane reforming, thereby reducing both cost and carbon emissions. However, it also appears that it could cost effectively capture carbon dioxide from the natural gas reforming process and sell it to local companies who can use it in a process that would sequester it permanently. While the costs of such "blue hydrogen" are not as low venting the carbon dioxide, it is still comparable to the status quo – and in the coming years, costs that are now external are likely to become internal. Further, as SARTA's fleet grows, it is possible that on site electrolysis will prove be the most cost-effective strategy to make low emission hydrogen. Improvements in electrolysis technology, together with falling prices for clean electricity generation, have already begun to make electrolysis-based hydrogen generation competitive.

1.0 Introduction

1.1 Background

This paper results from the expansion of a case study, commissioned by the Renewable Hydrogen Fuel Cell Collaborative (RHFCC), investigating economical and sustainable production of hydrogen for use in fuel cell electric vehicles (FCEVs) at the Stark Area Regional Transit Authority (SARTA) in Canton, Ohio. The original case study was led by CALSTART, and was posted on the RHFCC website in May 2020.[1] This expansion is intended to further explore and evaluate alternative low carbon emission strategies for hydrogen generation on site at SARTA.

SARTA expects to operate a fleet of 17 regular and paratransit hydrogen fuel cell electric buses by the end of 2021, with a hydrogen load of up to 500 kg/day. As with most hydrogen currently in use throughout the United States, SARTA's hydrogen is currently derived from natural gas through a process called steam methane reformation (SMR), which hydrogen is then trucked to, stored and dispensed from SARTA's refueling station. This process relies upon natural gas, and while significantly cleaner than producing diesel to be burned in conventional bus engines, it still yields significant CO_2 emissions. Further, reforming natural gas is least costly when done at large centralized plants, as is done for making SARTA's hydrogen. However, there are significant costs—and emissions—associated with transporting hydrogen to its point of end use.

SARTA has an interest in reducing these emissions and costs. Accordingly, it determined to undertake this study to evaluate strategies for how this could be accomplished. The following discussion reports not only strategies that have been identified through the case study, but also how those strategies compare to alternative strategies. Some of those alternatives are set forth in the previously referenced study undertaken for SARTA and RHFCC looking at on site hydrogen strategies.

Most of the barriers to the adoption of hydrogen fuel cell vehicles have been or will soon be surmounted. Fuel cell costs have come down, while performance has been going up. The cost of hydrogen is also no longer a barrier to its use – the principal feedstock to make hydrogen – natural gas – has been at historically lows for over five years, while economically recoverable reserves continue to be identified. Yet two obstacles remain to be resolved before hydrogen can be generally adopted for transportation.

[1] J.Cole, M. Marshall, "Expansion of SARTA Refueling Infrastructure: A Feasibility Study," CALSTART (commissioned by RHFCC/SARTA) (2020), http://www.midwesthydrogen.org/site/assets/files/1413/sarta_expansion_hydrogen_refueling_capabilities_final.pdf

First, the cost of building hydrogen refueling infrastructure is high, and a refueling infrastructure must be available to enable a transition to hydrogen-based transportation systems. And second, hydrogen derived from steam methane reformation is not a zero-emission fuel – even though carbon dioxide emissions from fuel cells are much lower than the incumbent technologies, which require the burning of diesel fuel or compressed natural gas.

The first problem will be addressed initially by tethered fleets – trucks, vans and buses that are tied to strategically located refueling stations. The most likely first adopters will be either transit agencies or operators of long-haul, big-load trucks, both of which require significant vehicle range.[2] The second problem may eventually be resolved through electrolysis of water using renewable or nuclear power. Renewable power costs are dropping, and electrolysis technology is rapidly improving. But a more likely near-term solution will be to reform natural gas into hydrogen, to capture the carbon dioxide emissions, and thereafter ship the carbon dioxide for nearby sequestration or use.

SARTA has enabled early stage adoption by acquiring a hydrogen bus fleet and tethering it to its on-site hydrogen refueling infrastructure. Currently SARTA has its hydrogen manufactured through large scale SMR in Ontario, Canada, and delivered to Canton, Ohio by truck. With this research, SARTA seeks to identify and understand alternative carbon emission strategies for obtaining hydrogen.

This paper will present a life-cycle cost breakdown from production through delivery and consumption of dispensed hydrogen generated for SARTA FCEVs using three different methods: (1) steam methane reforming of natural gas without carbon capture, utilization and storage; (2) steam methane reforming of natural gas *with* carbon capture, utilization and storage; and (3) splitting water using an electric current generated by solar energy (i.e. electrolysis). These costs will be converted into a $/diesel-gallon-equivalent basis and compared to the costs associated with the incumbent strategy of producing, delivering, and consuming fossil fuel.

This analysis will be performed under two location scenarios for SMR hydrogen production: a) at a large centralized plant with hydrogen delivered to SARTA; and b) production on-site at SARTA. Centralized production takes advantage of economies of scale to yield cheaper hydrogen per unit mass than can on-site production. However, the cost to transport centrally produced hydrogen is about twice the cost of production,[3] so local generation may both cost less and produce fewer

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[2] https://www.transit.dot.gov/regulations-and-guidance/environmental-programs/transit-environmental-sustainability/transit-role

[3] *See* Reddi, K., et al. Argonne National Laboratory. (2017). *Impact of Hydrogen Refueling Configurations and Market Parameters on the Refueling Cost of Hydrogen*. https://www.osti.gov/biblio/1393842

emissions. The study will consider strategies to optimize the location and method of hydrogen production for SARTA to minimize total economic cost, while also reducing negative externalities associated with CO_2 emissions.

1.2 The Need for Clean Hydrogen

There is an emerging international consensus that clean hydrogen will play a critical role in the world's transition to a sustainable energy future.[4] The use of hydrogen gas as a transport fuel has long been touted as a potential low-carbon alternative to refined oil products. For heavy-duty vehicle markets, FCEVs powered by hydrogen are expected in the near-term to be a viable low-carbon mobility option that will play an important role in reducing greenhouse gas emissions.[5]

Fuel cell electric buses (FCEBs) in particular are nearing operational equivalence with conventional vehicles powered by fossil fuels. Early deployments in both the United States and Europe have demonstrated performance characteristics for FCEBs that are comparable to diesel buses with regard to range, refueling time, ability to ascend a steep slope while maintaining normal operating speeds (i.e. gradeability), and route flexibility.[6] In Northern California, for example, where Oakland-based AC transit first started deploying FCEBs in 2005, a recent analysis performed by that agency found that 95% of its daily bus assignments could be served by FCEBs on a 1:1 replacement basis for diesel or compressed natural gas (CNG) vehicles.[7]

Fuel cell electric buses are also projected to reach cost parity with internal combustion engine vehicles (ICEVs) such as diesel and CNG toward the middle of this decade. As outlined in a 2019 study by Deloitte, while the U.S. purchase price for a FCEB is currently around twice that of its ICEV counterpart, this cost for initial procurement of fuel cell buses is projected to decline at a rate of about 7% annually between now and the end of the decade while similar ICEV costs are

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[4] *See* International Renewable Energy Agency. (2019). *Hydrogen: A Renewable Energy Perspective*. https://www.irena.org/publications/2019/Sep/Hydrogen-A-renewable-energy-perspective. *See also* International Energy Agency (2019). *The Future of Hydrogen: Seizing Today's Opportunities*. https://www.iea.org/reports/the-future-of-hydrogen

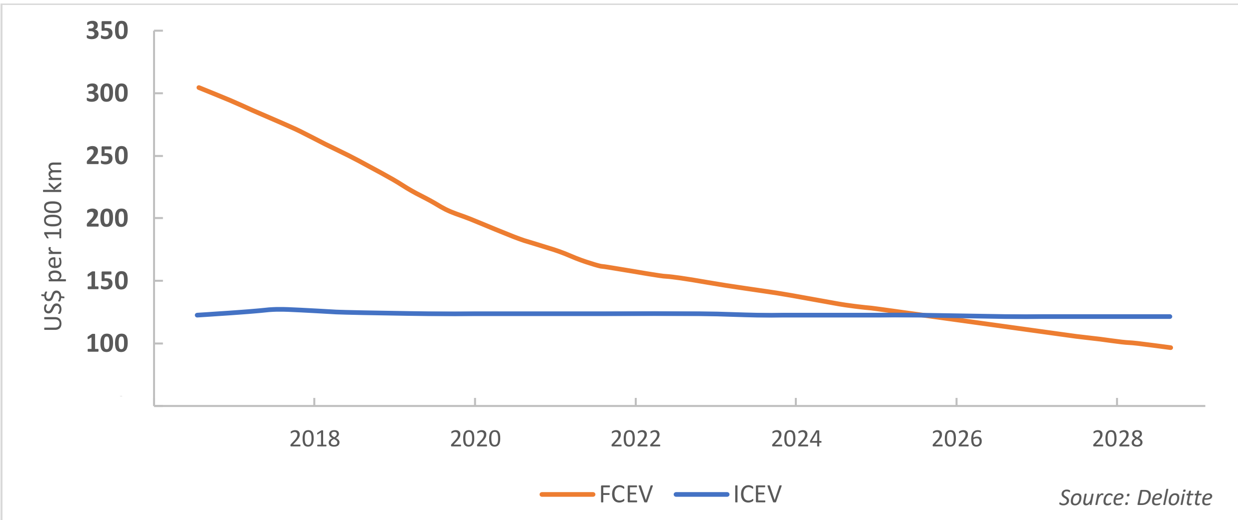
[5] *See* International Renewable Energy Agency. (2018). *Hydrogen from Renewable Power: Technology Outlook for the Energy Transition*. https://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power

[6] *See* California Transit Association. (2019). *Hydrogen and Fuel Cell Electric Transit 101*. *See also* Fuel Cells and Hydrogen Joint Undertaking (Public-Private Partnership with European Commission). (2015). *Fuel Cell Electric Buses: Potential for Sustainable Public Transport in Europe.* https://www.fch.europa.eu/sites/default/files/150909_FINAL_Bus_Study_Report_OUT_0.PDF

[7] *See* AC Transit. (2018). *Progress Report on the District's Study on ZEB Expansion and Facilities Assessment.* http://www.actransit.org/wp-content/uploads/board_memos/18-134%20ZEB%20Assessment.pdf. *See also* AC Transit. (2017). *AC Transit Becomes Only Bay Area Transit Agency Awarded a CCI Grant for 10 Zero-Emission Buses.* http://www.actransit.org/2017/02/14/ac-transit-becomes-only-bay-area-transit-agency-awarded-a-cci-grant-for-10-zero-emission-buses/

forecast to be relatively stable over this same timeframe.[8] As illustrated in Figure 1 showing the projected total cost of ownership for fuel cell and internal combustion buses in terms of dollar-per-distance-travelled (inclusive of both purchase and operating costs), declining costs brought about by economies of scale and improvements in technology and supply chain for FCEBs could lead to cost parity with comparable diesel and CNG buses by 2026.[9]

Figure 1. U.S. Total Cost of Ownership for a Bus Outlook ($/100 Km)



While hydrogen is clean at the point of consumption when used to power FCEVs, with no tailpipe emissions other than water, there are can be varying amounts of greenhouse gas emissions (GHG) associated with using the gas based on how it is produced. Ninety Five percent of the hydrogen produced in the United States is made from natural gas reformed in large central plants.[10] This process of steam-methane reformation (SMR) separates hydrogen from a methane molecule, which is a chemical compound consisting of 4-parts hydrogen to 1-part carbon, yielding a stream of hydrogen gas by the application of heat and pressure. One of the problematic byproducts of this production method is the leftover carbon dioxide, which if released into the atmosphere, adds to the greenhouse effect that raises global temperatures.[11] On average, this type of hydrogen production emits 9 kg of CO_2 for every kg of H_2 produced.[12]

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[8] *See* Deloitte. (2019). *Fueling the Future of Mobility: Hydrogen and Fuel Cell Solutions for Transportation.* https://www2.deloitte.com/content/dam/Deloitte/cn/Documents/finance/deloitte-cn-fueling-the-future-of-mobility-en-200101.pdf

[9] *Id.*

[10] Hydrogen and Fuel Cells Technologies Office. U.S. Department of Energy.

[11] National Oceanic and Atmospheric Administration. U.S. Department of Commerce. (2020). *Climate Change: Atmospheric Carbon Dioxide*. https://www.climate.gov/news-features/understanding-climate/climate-change-atmospheric-carbon-dioxide

[12] Argonne National Laboratory. (2019). *Updates of Hydrogen Production from SMR Process in GREET 2019.* https://greet.es.anl.gov/publication-smr_h2_2019

Any strategy for hydrogen use in transportation should therefore account for net CO_2 emissions from a comprehensive life-cycle perspective if it is to be effective in curtailing climate change. If hydrogen is indeed to play an important role in ushering in a sustainable energy future, cleaner methods of producing it must be used. One alternative to the dominant SMR process is to use electricity derived from renewable sources such as the sun to split a water molecule into its constituent parts: oxygen and hydrogen. Another option, and the focus of this paper, is to capture the carbon produced via SMR and to either: a) store it underground in geologic formations such as salt caverns or in depleted oil and gas reservoirs;[13] or b) use it as a feedstock to make other things such as construction materials such as cement, synthetic fuels, or new materials such as carbon fiber.[14] Such a carbon capture, utilization and storage (CCUS) approach, properly implemented and managed, could result in net-zero atmospheric CO_2 emissions or possibly even a negative carbon footprint across the lifecycle of a given productive process.[15]

However, under existing technologies for vehicle and fuel production, there is a tradeoff between life-cycle CO_2 emissions for transit buses and the financial cost of producing the fuel for these vehicles. Namely, vehicle technologies with lower emissions have higher associated fuel production costs. Table 1 shows the well-to-wheels emissions (equivalent to life-cycle emissions; "well" refers to natural gas well) for hydrogen fuel cell and diesel buses operating in the U.S. alongside the cost of producing the requisite fuel for these vehicles on a diesel-gallon-equivalent (dge) basis.[16] Emissions data comes from Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model sponsored by the U.S. Department of Energy that simulates the energy use and emissions output of various vehicle and fuel combinations.[17] The unit cost of production for diesel and hydrogen under different production methods was gathered from reports by the U.S. Energy Information Administration (EIA), the International Energy Agency, and S&P Global.[18] As shown in Table 1, there is currently

[13] *See* Intergovernmental Panel on Climate Change. (2005). *IPCC Special Report on Carbon dioxide Capture and Storage* (Chapter 5). https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_chapter5-1.pdf

[14] *See* Center for Climate and Energy Solutions. (2019). *Carbon Utilization: A Vital and Effective Pathway for Decarbonization.* https://www.c2es.org/document/carbon-utilization-a-vital-and-effective-pathway-for-decarbonization/

[15] *See* Núñez-López, V., et al. Gulf Coast Carbon Center. University of Texas at Austin. (2019). *Environmental and Operational Performance of CO2-EOR as a CCUS Technology: A Cranfield Example with Dynamic LCA Considerations*. https://www.osti.gov/pages/biblio/1493096

[16] Costs included here do not account for negative externalities such as the social cost of carbon. Diesel-gallon-equivalent figures for hydrogen production methods were calculated based on one gallon of diesel having 113% the energy content of 1 kg of hydrogen; *see* Alternative Fuels Data Center. U.S. Department of Energy. (2014). *Fuel Properties Comparison*. https://afdc.energy.gov/fuels/fuel_comparison_chart.pdf

[17] All scenarios assume truck delivery to a refueling station that is 100 miles away from the point of production. *See* Argonne National Laboratory. (2019). *GREET Model*. https://greet.es.anl.gov/

[18] *See the following:* a) U.S. Energy Information Administration. U.S. Department of Energy. (2020). *Gasoline and Diesel Fuel Update*. https://www.eia.gov/petroleum/gasdiesel; b) International Energy Agency. (2019). *The Future of Hydrogen: Seizing Today's Opportunities*. https://www.iea.org/reports/the-future-of-hydrogen; c) S&P Global.

an inverse relationship between emissions for this selection of vehicle technologies and the cost of fuel production, with lower emissions being associated with higher costs.

Table 1. Emissions and Production Costs for Fuel Cell and Conventional Transit Buses Using Hydrogen and Diesel

Vehicle & Fuel Type	Well-to-Wheels CO_2 Emissions (kg/mile)	Unit Production Cost for fuel ($/dge)	Average Miles Traveled per dge[19]	Production Cost per Mile Traveled
FCEB: H_2 from electrolysis with renewable power	0.40	$4.99	7.0	$0.71
FCEB: H_2 from natural gas with CO_2 sequestration	0.57	$1.70	7.0	$0.24
FCEB: H_2 from natural gas without CO_2 sequestration	1.84	$1.13	7.0	$0.16
ICEB: Low-sulfur diesel	2.93	$0.84	3.7	$0.23

Hydrogen production from natural gas in combination with CCUS -- also known as "blue" hydrogen -- is expected to be the least-cost, low-carbon option for clean hydrogen in the near term, especially in regions where inexpensive natural gas is readily available.[20] U.S. natural gas prices, which are currently near historic lows, are projected to remain relatively low over the next decade, driven in large part by the continued development of shale plays in states such as Ohio, Pennsylvania, and West Virginia.[21] Blue hydrogen has been proposed by intergovernmental organizations such as the International Renewable Energy Agency (IRENA) as a bridging solution: as the cost of producing hydrogen from renewable power decreases, it can offer the prospect of continuity to fossil fuel producers while also helping to achieve climate objectives at acceptable costs.[22]

(2020). *Cost, Logistics Offer 'Blue Hydrogen' Market Advantages Over 'Green' Alternative*. https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/031920-cost-logistics-offer-blue-hydrogen-market-advantages-over-green-alternative

[19] Average fleet fuel efficiency for FCEBs comes from the National Renewable Energy Agency's evaluations of vehicle deployments at transit agencies as of 2018 available at https://www.nrel.gov/docs/fy19osti/72208.pdf. *See also* https://afdc.energy.gov/data/. Average fleet fuel efficiency for diesel transit buses comes from the U.S. Department of Energy's Alternative Fuels Data Center's most recent estimate of average fuel economy by major vehicle category available at https://afdc.energy.gov/files/u/data/data_source/10310/10310_fuel_economy_by_vehicle_type_3-26-20.xlsx

[20] International Energy Agency. (2019). *Transforming Industry through CCUS*. https://webstore.iea.org/download/direct/2778

[21] *See* U.S. Energy Information Administration. U.S. Department of Energy. (2020). *Annual Energy Outlook 2020*. https://www.eia.gov/outlooks/aeo/

[22] International Renewable Energy Agency. (2019). *Hydrogen: A Renewable Energy Perspective*. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf

2.0 Markets for Carbon Captured from Hydrogen Generation

2.1 CO_2 Utilization in the United States

The beneficial reuse of carbon dioxide (CO_2 utilization, or CCU) has been practiced for decades in the United States. Currently, a little over 70 million tonnes (Mt)[23] of CO_2 is used for chemical and physical purposes including as a precursor for polymers, in fire suppression, as an inert gas in welding and food storage, in beverage carbonation, in concrete building materials (curing and as an aggregate replacement), and in fertilizer production.[24] However, by far the largest use of CO_2 in the United States is for enhanced oil recovery (EOR) where annually roughly 65 Mt of CO_2 are injected into the subsurface for the purpose of enhancing the recovery of crude oil. The next largest use of CO_2 is in urea manufacturing, consuming nearly 5 MtCO2 per year. A complete listing of CCU opportunities are listed in Table 2 on a state-by-state basis for Ohio and neighboring states along the I-80 corridor.

There are many factors to consider when choosing a utilization partner, including utilization readiness level, incumbent CO_2 supplier, proximity to CO_2 provider, and the economics of the CO_2 partnership. Utilization readiness is an indicator analogous to technological readiness, and is used to qualify utilization partners in terms of the likelihood to accept CO_2 as an input. The qualifying factors associated with utilization readiness are complex, but can be summarized in the following considerations:

- does the potential utilization opportunity have a physical location or is the described opportunity theoretical?
- if the utilization opportunity has a physical presence, does it currently take CO_2 as an input or does the process need to be modified to accept CO_2?
- how do contracts with incumbent CO_2 suppliers impact the viability of new CO_2 supply chains?

Siting of potential future utilization opportunities is an important part of developing robust markets for CO_2. For example, a regional hot-spot analysis could reveal the ideal location for a CO_2-to-fuel operation based on proximity to both incoming feedstocks and potential markets for finished products. In this sense, new CCUS sinks offer flexibility in terms of location which can be rationally dictated through careful management and optimization of total supply costs for

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[23] A "tonne" is a metric ton, and equivalent to 1.102 US tons. The international system of measurement has been adopted in the US for carbon dioxide emissions. Note also that the CO2 emission industry does not follow the natural gas industry convention of using "M" to represent "1,000" and "MM" to represent one million (based upon Roman Numberals). Instead, it uses "K' to represent 1000, and M to represent one million.

[24] Psarras, Peter C., et al. "Carbon capture and utilization in the industrial sector." *Environmental Science & Technology* 51.19 (2017): 11440-11449.

Table 2. Top Potential CO2 Markets in the Midwest Region of the I-80 Corridor

Process	Current Estimated Demand (ktCO2 / yr)	Number of Sites
Ohio		
Urea Manufacturing	315.4	1
Food and Beverage	73.7	56
Refrigeration	38.6	111
Methanol	16.0	2
Plastic and Polymers	3.8	9
Michigan		
Enhanced Oil Recovery	323.2	9
Food and Beverage	84.8	54
Refrigeration	47.6	114
Plastic and Polymers	10.4	16
Chemical Production	0.0	1
Indiana		
Food and Beverage	36.4	24
Refrigeration	19.8	57
Methanol	10.2	1
Plastic and Polymers	8.5	6
Pennsylvania		
Food and Beverage	90.2	63
Refrigeration	42.5	143
Chemical Production	16.4	4
Plastic and Polymers	6.5	12
Miscellaneous	0.4	2

feedstocks and distribution costs for finished products. Additionally, theoretical utilization sites are not tied into incumbent CO_2 contracts and would be designed to accommodate CO_2 as a feedstock or process input. The downside to theoretical utilization opportunities are the uncertainties and risks in assuring long-term economic viability, notably in minimizing risk for potential investors. Existing facilities may carry less economic risk but are complicated by the presence of incumbent suppliers or the need to heavily modify existing infrastructure or equipment to accommodate CO_2 reuse (e.g., replacing R-134A refrigerant with CO_2 in commercial systems).

Proximity of the source-sink CO_2 partnership is crucial to minimizing delivery costs. In general, for small scale transport of CO_2 in compressed tanker trucking, a transport cost of between \$0.16 and 0.18 is incurred per tonne of CO_2 per mile transported.[25] Low cost CO_2 disposal is a function of both cost-efficient CO_2 capture at the point-source and close proximity to the end-user. Geographic Information Systems mapping and spatial analysis tools are invaluable for optimizing source-sink pairings as a function of the parameters mentioned above. For theoretical utilization siting, it is necessary to consider locations that will jointly minimize the transport of CO_2 to an end-user as well as any downstream products to their respective markets.

The economics of carbon capture are governed by the cost of on-site capture, the cost of compression and delivery to a suitable off-taker, the purchase price offered by the off-taker, and any applicable market incentives (e.g., tax credits). The capture of carbon from point sources requires equipment and energy, and the economics of point source capture is largely expected to follow an inverse-dilution relationship: as the concentration of CO_2 in the targeted exhaust stream increases, the efficiency of separation increases, driving costs down. Hence, industrial processes that produce higher purity exhaust streams (e.g., ammonia production, natural gas processing, ethanol production) are often the first exploited for CO_2 capture in the merchant CO_2 market.[26]

Hydrogen generation from SMR produces a fairly high purity stream of CO_2 by mol% (ca. 45%) when compared to other industrial emitters, e.g., cement production (ca. 27%), iron and steel production (ca. 25%); and far higher purity streams than found from coal and natural gas power plants (ca. 12 and 5%, respectively). For this reason, blue hydrogen production can serve as a low-cost source of industrial CO_2. The contract price for CO_2 is not often disclosed due to confidentiality agreements between sink and provider, but industry analysis shows that cost of delivered CO_2 ranges from \$40-\$50 to \$400-\$600 per short ton, where costs are sensitive to purity, purity certification, supply distance, regional supply and demand, and competitive discounting.[18]

An additional source of revenue may be available in the form of tax credits. The Bipartisan Budget Act of 2018 stipulates that under the revised 45Q tax code,[27] CO_2 captured from an industrial facility and reliably stored in a geological reservoir is eligible for a credit of upwards of \$50/tCO_2,[28]

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[25] Assuming 20 tCO_2/payload.

[26] Bains, Praveen, Psarras, and Wilcox. "CO2 capture from the industry sector." *Progress in Energy and Combustion Science* 63 (2017): 146-172.

[27] U.S. House of Representatives. *H.R.1892 - Bipartisan Budget Act of 2018: Division D Revenue Measures: Title II 689 Miscellaneous Provisions - Sec. 41119*. https://webstore.iea.org/insights-series-2015-storing-co2-through-enhanced-oil-recovery

[28] Geologic storage must be verified through proper measurement and verification methods.

and CO_2 captured for the purpose of beneficial reuse (e.g., EOR or beverage carbonation) may be eligible for up to \$35/tCO_2. Several conditions exist for eligibility. First, a qualified facility must commence construction prior to January 1, 2024. Second, a qualified facility that would not emit more than 500,000 tCO_2 in a given taxable year must capture greater than 25,000 tCO_2/yr; hence, only large (50,000 kg H_2) blue hydrogen production facilities may generate enough CO_2 to qualify for the tax credits ascribed under the Federal tax code 45Q.[29] Due to complications with credit payout, many companies elect to work through tax equity partnerships which reduce the overall 45Q credit by 15-20% due to transactional fees.

Some express concern that utilization distracts from the primary motivation of reducing atmospheric CO_2, where geological storage offers a secure and direct route to keeping CO2 from re-entering the atmosphere on a meaningful timescale (>100 years).[30] However, many utilization opportunities result in reduced emissions by way of product substitution, where the conventional production route has a higher carbon intensity than the utilization route. This underlies the importance of full cradle-to-grave life cycle analyses (LCA) in any blue hydrogen capture system. Hence, an integrated lifecycle assessment and techno-economic analysis LCA/TEA will be performed to assess the economics of various pathways in the context of carbon emission reductions.

2.2 Enhanced Oil Recovery

Enhanced oil recovery is an excellent target for CCU. It creates a strong and continuous demand for CO_2, and the CO_2 remains stored permanently in the reservoir once injected.[31] Industrially, over 80% of the CO_2 used in EOR is sourced from natural reservoirs, e.g. the McElmo formation in Colorado and the Jackson Dome in Louisiana (these two sources provide roughly 40 MtCO_2 per year for the purpose of EOR). CO_2 captured from industrial sources where a high purity stream of CO_2 exists (e.g., natural gas processing) can provide another source for CO_2-EOR, albeit at a slight cost premium when compared to natural sources. Low cost CO_2 is important to the EOR operator as it represents the major operational expense in an EOR project and will – together with the price of crude oil – dictate project economic impact.

[29] Applicable tax credit claims for beneficial reuse are subject to IRS lifecycle analysis guidelines.
[30] Abanades, J. Carlos, et al. "On the climate change mitigation potential of CO2 conversion to fuels." *Energy & Environmental Science* 10.12 (2017): 2491-2499.
[31] Núñez-López, Vanessa, Ramón Gil-Egui, and Seyyed A. Hosseini. "Environmental and Operational Performance of CO2-EOR as a CCUS Technology: A Cranfield Example with Dynamic LCA Considerations." *Energies* 12.3 (2019): 448.

For example, Fukai et al.[32] ran an analysis of an Ohio EOR operation at three crude oil cost points: \$120/bbl, \$80/bbl and \$40/bbl. The breakeven cost (the maximum cost an EOR operator can pay for CO_2 before net loss in revenue) was found to be \$10/tCO_2 at the \$40/bbl scenario and the value of CO_2 generally increased by \$4.31 for every \$1 increase in the cost of oil. This assumes average industrial utilization rates of CO_2, or the amount of CO_2 injected to produce a single barrel of oil. This rate can fluctuate between 0.3 and 0.6 tCO_2 per bbl for traditional EOR management, while higher rates are achievable in advanced EOR methods such as max storage EOR+ (MS-EOR) or advanced EOR+ (A-EOR). These methods exploit simultaneous oil recovery and carbon storage for profit, storing on average 0.77 tCO_2 and 0.50 tCO_2 per barrel of oil produced, respectively.

An added advantage of these advanced methods is they afford the EOR operator flexibility to simultaneously store CO_2 while running EOR or to choose one or the other as market conditions dictate. A single barrel of oil will result in the emissions of roughly 0.42 tonnes CO_2 upon combustion, and additional emissions associated with upstream processes, refining of the crude oil to finished gasoline, diesel or jet fuel, and transportation of product; hence, any utilization rate in excess of the collective lifecycle emissions will result in net CO_2 storage. For a typical EOR field, the recommended utilization rate to ensure carbon neutrality over the lifetime of the project is around 0.5 – 0.6 tCO_2/bbl, but this number is dependent on a number of local factors including field characteristics, injection pressure, gas processing method, and local grid carbon intensity for electric power support. Regardless, EOR is a potential high-capacity sink for CO_2 and can absorb the CO_2 emitted from higher volume centralized production facilities.

2.3 Concrete Products

Cement production is responsible for roughly 7% of global CO_2 emissions, with anticipated growth between 12 and 23% by 2050.[33] Typical concrete has a volumetric composition of 60 – 75% aggregate, 7 –15 % cement, 14 – 18% water, and up to 8% air. However, synthetic aggregate can be formed from the direct reaction between carbon dioxide and a source of alkalinity to yield solid carbonates. Use of synthetic aggregate made from CO_2 has two major advantages over conventional concrete production: 1) synthetic aggregate can replace a portion of other coarse and fine aggregates (e.g., sand and dolomitic limestone) potentially reducing emissions associated with material mining, transport and handling; and 2) incorporation of synthetic aggregate can lead to a lower block density, leading to a reduction in the mass of cement required

[32] Fukai, Isis, Srikanta Mishra, and Mark A. Moody. "Economic analysis of CO2-enhanced oil recovery in Ohio: Implications for carbon capture, utilization, and storage in the Appalachian Basin region." *International Journal of Greenhouse Gas Control* 52 (2016): 357-377

[33] iea.org, 2009. Technology Roadmap - Cement [WWW Document]. URL https://www.iea.org/reports/technology-roadmap-cement

to achieve the equivalent structural build (with the assumption that the product with synthetic aggregate possesses equivalent mechanical strength).

Unlike for EOR, the utilization rate of CO_2 in ready-mixed concrete (RMC) is very low, typically under 1% by mass. For example, for every 1 m^2 of wall (approximately 156.5 kg by mass), only 1.4 kg of CO_2 is incorporated into the material. Ultimately, any concrete building material made from CO_2 has to meet strict sector and building code guidelines in terms of material performance, which places a low ceiling on the allowable incorporation of CO_2. Additionally, RMC begins hydration the moment water makes contact with cement; thus, transport distance is crucial to keep travel times short and the concrete mixture in workable condition. As such, RMC plants tend to be dispersed, lower volume operations, with an average shipment distance of 32 miles (compare to the average distance of 546 miles for all industrial commodities). Given these considerations, a typical RMC plant using CO_2 as an input will have a demand for CO_2 between 340 and 1700 t/yr. Further, RMC plants experience a relatively high turnover rate of roughly 30% every 5-year period, driven largely by the continuing evolution of construction demands.[34] Hence, RMC operators looking to dismantle and re-locate to areas where they can operate at greater profitability, and perhaps simultaneously looking to align with any sustainable development goals, could make strong candidates for theoretical utilization opportunities in regions where there is a reasonable outlook for construction growth.

2.4 Beverage Carbonation

Between 2 and 3 $MtCO_2$ are used to carbonate beverage products in the United States each year. The International Society of Beverage Technologists (ISBT) specifications on CO_2 used in food and beverage stipulates that the CO_2 must be of high purity (99.9% + CO_2 by volume) and must meet maximum thresholds on all other specified contaminants, including NOx compounds, hydrocarbons, and total sulfur content (< 1.0 ppm total sulfur allowed v/v). These facilities are fairly widespread and dispersed, as indicated in Table 2 where it is the second most abundant utilization opportunity in each state.[35] The average demand per site in the OH-MI-IN-PA region is around 1500 tCO2/yr and ranges between 4 and 15,000 tCO2/yr, the larger representing centralized bottling plants in major cities. All beverage carbonation facilities have incumbent CO_2 suppliers, likely from industrial gas suppliers. While ISBT grade is expected to command a higher market price than lower purity, bulk CO_2, it is unclear how newly sourced CO_2 effects local supply and demand and competitive pricing models. There may exist an opportunity to solicit partners attempting to fulfill one or more corporate renewable portfolio objectives.

[34] Syverson, Chad. "Markets: Ready-mixed concrete." *Journal of Economic Perspectives* 22.1 (2008): 217-234.
[35] It should be noted that these opportunities currently take CO_2 as an input, whereas the most abundant opportunity (refrigeration in large chain supermarkets) is not currently configured to take CO_2.

2.5 Other Markets for Carbon Dioxide

Outside of EOR, ready mixed concrete and beverage carbonation, CO_2 can be used locally in various smaller applications such as in chemical production, fireproofing, as a physical solvent in separations, and in other niche applications. With the exception of urea manufacturing, the demand for these opportunities are expected to be much smaller than those for EOR, RMC, and beverage carbonation. Urea manufacturing often uses on-site CO_2 generated in the production of ammonia; thus, they are not likely to be viable targets for merchant CO_2. Though not detailed in the following analysis, these remaining small-scale opportunities represent a number of potential partnerships to explore via the same mechanisms to be described below.

2.6 Saline Storage

Carbon dioxide can be stored in the supercritical state ($\rho = 600\ \mathrm{kg/m^3}$) in deep sedimentary formations or in depleted oil and gas reservoirs. Suitability of storage depends largely on reservoir characteristics, where ideal storage conditions involve depths in excess of 1 km (to ensure CO_2 is stored in the more dense supercritical state as opposed to the gaseous state, where the former allows for more CO_2 stored per reservoir volume), high porosity and high permeability. Formations with high porosity and permeability include sandstone, limestone, dolomite, or basalt. Ensuring long-term storage depends on the quality (impermeability) of the capstone and the extent of secondary trapping mechanisms within the pore space. Characterization of suitable regions for geological storage in the Midwest[36] by the Midwest Regional Carbon Sequestration Partnership (MRCSP) reveals roughly 46.3 – 51.1 billion tonnes (Gt) of CO_2 storage potential in deep saline formations, with the East Canton Consolidated and Morrow Consolidated fields representing 500 $MtCO_2$ and 26 $MtCO_2$ of potential storage, respectively.[37] There is an estimated 6 $GtCO_2$ storage potential in the saline formations associated with Ohio alone.[38] Hence, the capacity for suitable storage in Ohio and the surrounding regions is not expected to be a limiting factor in designing EOR or storage partnerships.

3.0 The Implication of Source-Sink Pairing on Lifecycle Carbon Emissions

From an economic standpoint, SMR generation of hydrogen is the least cost option, particularly in regions with low natural gas pricing. This is perhaps why around 95% of the hydrogen produced

[36] Region encompasses the states of MI, IN, OH, PA, WV, and KY.

[37] Dooley, James J., Robert Dahowski, and Casie Davidson. *The Midwest Regional Carbon Sequestration Partnership (MRCSP)*. Battelle Memorial Institute, 2005.

[38] Carter, Kristin M., et al. "Characterization of geologic sequestration opportunities in the MRCSP region: Middle Devonian-Middle Silurian formations: MRCSP Phase II Topical Report under DOE Cooperative Agreement No." *MRCSP Phase II Topical Report under DOE Cooperative Agreement No. DE-FC26-05NT42589* (2010).

in the US goes through this route. However, as indicated earlier, the carbon footprint of SMR is high (ca. 9 $kgCO_2$ per kgH_2 produced), and thus environmental concerns over reducing emitted carbon support the adoption of less carbon intensive production routes (e.g., blue and green). These same considerations extend beyond the production of H_2 to the fate of captured CO_2. Generally speaking, utilized CO_2 falls under one of three categories, as described recently by Hepburn et al:[39]

1. Closed pathway: carbon dioxide is removed from the atmosphere and stored in a non-atmospheric subsystem securely and permanently ($t_{1/2}$ = centuries / millennia stable).
2. Open pathway: carbon dioxide is removed from the atmosphere and stored in a non-atmospheric subsystem with the risk of large-scale flux back to the atmosphere ($t_{1/2}$ = decades).
3. Cyclic pathway: carbon dioxide is removed from the atmosphere and stored in a non-atmospheric subsystem non-securely and non-permanently ($t_{1/2}$ = days / weeks).

From a lifecycle emission standpoint, CO_2 in a closed cycle remains permanently[40] removed from the atmospheric stock. Both EOR and concrete products fall under the closed cycle classification, as the CO_2 is stored permanently in the oil and gas reservoir (EOR) or as a stable carbonate (concrete production). Beverage carbonation and many chemical routes will release carbon back to the atmosphere on the order of days to weeks and, for some long-lived chemicals and plastics, years. It is difficult to assess the impact of CO_2 utilization in these instances as there can be disagreement about how to treat CO_2 placed into the Technosphere on varying timescales. However, every example of CO_2 utilized to create a product can be compared to the conventional production pathway to assess the impact of CO_2 as a feedstock. For example, in concrete production, the incorporation of CO_2 into synthetic aggregates results in a less dense concrete product, lowering the amount of concrete needed per unit of building material, in turn reducing the amount of carbon intensive materials required (e.g., cement) and the amount of emissions generated in material handling and transport. The collective result is the lowering of emissions on the order of 9.9 $kgCO_2e/m^2$ concrete wall.[41]

Use of CO_2 in EOR can lower the carbon intensity of produced oil. When considering that fuel combustion releases CO_2 at the rate of ~ 73g CO_2/MJ fuel LHV and approximating a barrel of oil at 5.8 GJ diesel fuel LHV, EOR must utilize at least 0.42 tCO_2/bbl produced to account for combustion emissions alone. The ability to offset combustion emissions with stored CO_2 means

[39] Hepburn, Cameron, et al. "The technological and economic prospects for CO 2 utilization and removal." *Nature* 575.7781 (2019): 87-97.
[40] Permanent storage suggests minimal leakage (<0.01%) back to the atmosphere on timescales on the order of 100s to 1000s of years.
[41] McCord et al., "Global CO_2 Initiative Complete Mineralization Study," 2018. DOI 10.3998/2027.42/147467

that the only net emissions to the atmosphere in CO_2-EOR come by way of product refining, transport and storage. The end result here means reductions of carbon intensity by 40 – 90% when compared to conventional gasoline, diesel and jet fuel pathways.

There is little evidence to support the notion that CO_2 captured from an industrial source and used in the beverage market results in reduced emissions when compared to conventional sourcing from industrial gas suppliers. Further, as a cyclic pathway for carbon utilization, these emissions are often not treated as beneficial reuse of carbon and, importantly, do not qualify for beneficial reuse credits under 45Q.[42]

The following section outlines an analysis of reasonable opportunities for blue hydrogen production paired with utilization in the state of Ohio. First, large scale centralized operations are considered and paired with rational choices for utilization based on proximity and volume of CO_2. Next, smaller scale opportunities are explored for dispersed low-volume filling stations. Producing hydrogen in small amounts where it is needed, such as vehicle refueling stations, may be the most viable approach for introducing hydrogen in the near term in part because the initial demand for hydrogen will be low.[43] However, capital-intensive centralized production facilities that take advantage of economies of scale to generate lower costs per kg of hydrogen produced will be needed in the long term to meet the expected increase in hydrogen demand.

Both scales of operation will be compared to green hydrogen production, which is expected to have a higher cost of H_2 production at both scales but does not have to find an off taker for CO_2. Such a comparison – considering the full supply chain economics and full LCA – can reveal scenarios where either production route might be favored.

4.0 Strategies for Optimizing Carbon Use

4.1 Large Scale Hydrogen Production: 50,000 kgH$_2$/day

A large scale, a 50,000 kgH$_2$/day plant can capture approximately 310 tCO$_2$/day, or roughly 6.2 kgCO$_2$/kgH$_2$ produced. This works out to roughly 104000 tCO$_2$/yr for a plant operating at 92% availability. This is an important volume as any plant capturing in excess of 100000 tCO$_2$/yr can qualify for 45Q tax credits for EOR or storage. However, unanticipated downtimes could result in lower plant availability and would threaten to bring potential CO_2 capture potential below the

[42] These facilities fall short of the volumetric requirement as well (>25000 tCO2/yr), but the non-qualification of beverage carbonation results from the fact that ultimately this CO2 is cycled back to the atmosphere on short timescales.
[43] https://www.energy.gov/eere/fuelcells/central-versus-distributed-hydrogen-production

threshold. To ensure sufficient CO_2 capture, additional capture units could be placed at other SMR emission points, but this would likely increase the levelized cost of CO_2 avoided due to the more dilute nature of the carbon stream at these emission points (compare the CO_2 partial pressure at shifted syngas (1.7 bar), the PSA tail gas (0.75 bar) and the reformer flue gas (0.20 bar), where the partial pressure is expected to be inversely correlated to the real work required for separation, and hence cost). Instead, the H_2 plant could be slightly overbuilt for capacity to ensure that carbon capture thresholds are met and maintained. Recall, the 45Q credit for EOR or storage can scale from $35/tCO_2$ to $50/tCO_2$. The incremental capital to adjust the capacity of a 50,000 kgH$_2$/day to, for instance, 53,000 kgH$_2$/day (which would effectively add a 10% buffer to account for unanticipated outages) is roughly \$8M to the total installed cost. This amount amortized over a project lifetime of 20 years and weighted average cost of capital (WACC) of 5% leads to an increase of roughly \$1.5M per year in combined plant CAPEX and OPEX. As a comparison, loss of 45Q tax credits would result in a potential loss of \$2.8M per year for the 12 years of 45Q payout, or roughly \$1.7M per year over the 20-year project economic lifetime.

4.1.1 Single Source to Single Sink: EOR or Geological Storage

In this scenario, all of the CO_2 captured is transported to a single EOR or storage location for injection. The most promising option for EOR is in the East Canton Consolidated Oilfield (ECOF), or potentially the Morrow Consolidated Oilfield (MCOF). Unfortunately, neither of these oilfields currently implement CO_2-EOR. The nearest active CO_2-EOR operator is Core Energy near Traverse City, MI. With a distance of over 450 miles from the location of large-scale hydrogen facility in Canton, transport costs via pipeline or truck would make the project economically unviable. There is potential – however – to attract active EOR operators to expand into a more proximal region *if* a steady source of industrially captured CO_2 is available.

The anticipated cost of capture, compression, transport, injection, and any applicable tax credits or revenue are compiled in Table 3. Capture and compression are combined into one term, with compression to pipeline and trucking assumed to be comparable because the slightly lower conditions required for trucking compression (17 bar, -35ºC for trucking vs 100 bar for pipeline) are offset by the need to recompress trucked CO_2 prior to injection. Transport costs are specific to distance as set by location, and a flat injection fee is assumed as \$11/tCO$_2$ for both dedicated geologic sequestration and EOR. This cost reflects average literature values for injection and monitoring[44] applied to geologic sequestration and EOR.

[44] Monitoring and verification are necessary for qualified 45Q recipients to ensure injected CO_2 remains underground.

Table 3. Breakdown of CO2 Delivery and Injection Costs from Large Scale Hydrogen Production to Three Oilfields*

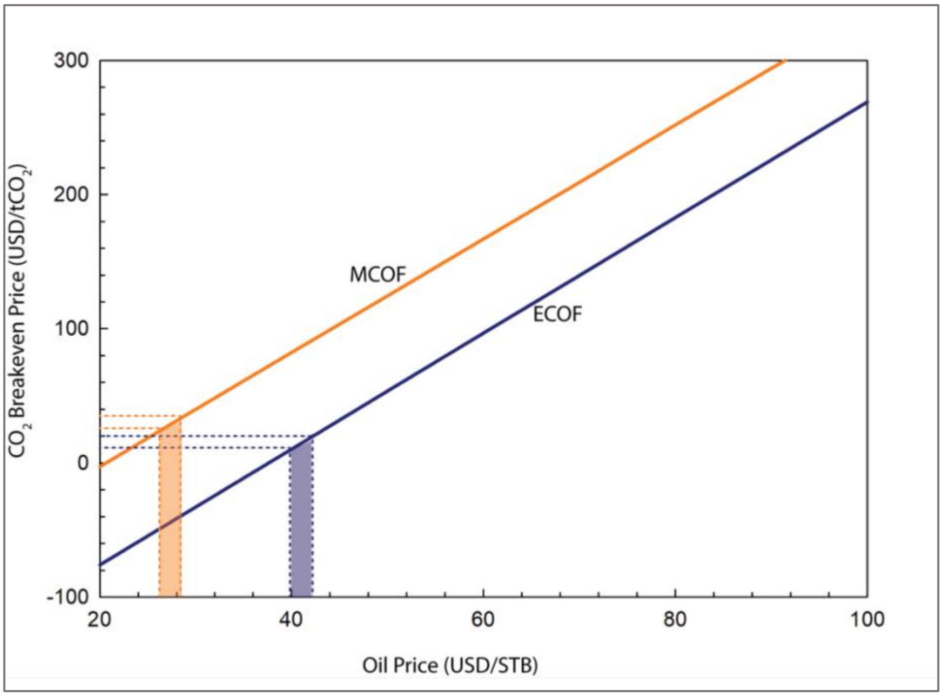
Destination	Distance (mi.)	Capture and Compression ($/t$CO_2$)	Pipeline / Trucking ($/t$CO_2$)	Total EOR/Storage ($/t$CO_2$) with injection, less credit[a]
ECOF	22	24	20/6	13/1
MCOF	83	24	68/17	24/12
Core Energy	450+	24	381/82	89/77

[a] All total costs calculated with trucking transport since it is the more economic option at all distances. The federal tax credit is applied at full escalation less 20% for tax equity partnership transaction fees.

**The non-active EOR fields of ECOF and MCOF in Eastern and Northern Central Ohio, respectively, and the active fields operated by Core Energy in Northern Michigan.*

Costs for delivery by pipeline are cost prohibitive even at short distances due to the low volume of CO_2 transported and the minimum nominal pipeline diameter of 4 inches; thus, all costs for CO_2 transport are calculated assuming tanker trucking. When the 45Q tax credit is assumed at full escalation, and after subtracting transactional fees associated with tax equity partnerships, storage in the ECOF could be realized for as little as $1/tCO2 assuming that no significant site preparation is required, including treatment of existing wellheads. Additional costs associated with field preparation should be assigned on a site-specific basis. Using CO_2 for EOR in the ECOF can be achieved for as little as $13/t$CO_2$ under similar assumptions. However, EOR operators in the Permian purchase CO_2 from natural and anthropogenic sources at a rate of $20 to $40/tCO2. No such network of low cost exists in Ohio, yet. Hence, local operations will rely on steady, low cost streams of CO_2 from industrial source. To assess the potential of EOR in Ohio, Fukai et al. published an analysis on CO_2-EOR in Ohio whereby the CO_2 breakeven price is calculated as a function of oil price at a fixed discount rate of 15%. These results are adapted to reflect anticipated CO_2 purchase price for delivery from a blue hydrogen facility located in Canton and shown in Figure 2.

Figure 2. CO2 Breakeven Price as a Function of Oil Price for EOR in the MCOF (Orange) and ECOF (Blue) Field*



**Despite having a higher cost due to the more distant transport, EOR in the MCOF can be profitable if the cost of crude oil is above 28 USD/STB, whereas the cost must exceed 40 USD/STB in the ECOF. Adapted from Fukai et al. 2015.*

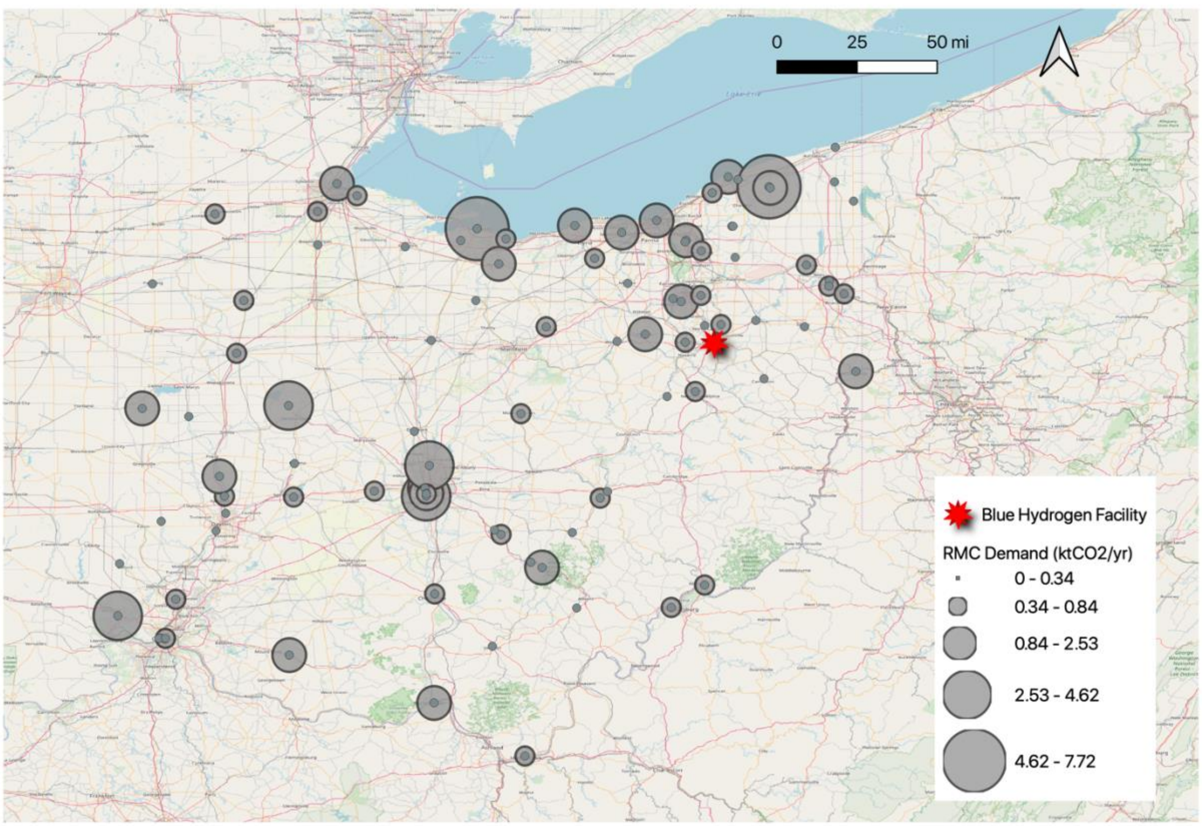
Figure 2 shows that for a CO_2 purchase price between \$24 and \$36/tCO_2, the EOR in the MCOF can be profitable if the price of crude oil is above \$28/STB. Conversely, at a CO_2 purchase price of \$13 to \$20/tCO_2, EOR in the ECOF can be profitable if the price of crude oil is in excess of \$40/STB. Here, despite the lower CO_2 purchase price for the ECOF due to shorter transport distance, a greater cumulative oil recovery in the MCOF leads to a lower threshold price for crude oil.

For maximum flexibility, an EOR operator could opt to run stacked storage, where injection wells run to both oil fields and saline storage reservoirs. Table 3 shows that the minimum cost of storage after application of the 45Q tax credit is \$1 and \$12/tCO_2 for the ECOF and MCOF respectively. Hence, in periods of crude oil price fluctuation or uncertainty, the EOR operator has the option to divert CO_2 to storage. This increased flexibility can reduce the risks associated with an uncertain oil future by pairing with the more stable and predictable economics of saline storage.

4.1.2. Single Source to Multiple Sink: Ready-Mixed Concrete

Figure 3 shows the geographical spread of RMC facilities in the State of Ohio. As described above, a large scale centralized blue hydrogen facility will capture over 100 ktCO_2/yr. The distribution of CO_2 demand by facility shows the majority of facilities with a demand under 1 ktCO_2/yr (Fig 4). Further, after consideration of *every* RMC facility in Ohio, there is not enough current demand to satisfy all of the 100 ktCO_2 captured; however, for beneficial reuse credits (non-EOR), the threshold is 25,000 tCO_2/yr; hence, it is important to understand the serviceable addressable market (SAM) as a function of distance. To examine the impact of RMC partnerships, service areas around the large blue hydrogen production facility are examined at 10, 25, 50, 75, 100, 125, 150, 175 and >200 mile radii. Results are shown in Table 4.

Figure 3. Ready Mix Concrete Locations in Ohio, Symbolized by Potential Annual CO2 Demand for the Purpose of Incorporation into Mixed Concrete Product.



**The proposed Blue Hydrogen Facility is assumed to be medium size and located in Canton, Ohio.*

Table 4. Service Area Analysis and Breakeven Price for Delivery of Captured CO2 to Ohio-based RMC Plants

Service Area (mi.)	Cumulative demand ($ktCO_2$/yr)[a]	Average weighted transport cost (\$/tCO_2)	CO_2 production cost[b] (\$/tCO_2)	CO_2 breakeven price (w/45q) (\$/tCO_2)	CO_2 breakeven price (w/o 45q) (\$/tCO_2)
10	1.5	3.6	27.6	1696	1724
25	5.2	5.2	29.2	457	485
50	12.0	7.7	31.7	191	219
75	31.1	11.3	35.3	71	99
100	45.7	13.5	37.5	50	78
125	57.0	15.1	39.1	42	70
150	66.2	16.6	40.6	39	67
175	71.6	17.7	41.7	38	66
200	78.7	19.6	43.6	39	67

[a] 45Q tax credits apply at 75-mile service area and beyond.

[b] Includes capture, compression and transport but no 45Q credits.

Figure 4. Distribution of RMC Plants by Potential Annual Demand for CO2 (kt/yr): the Majority of Plants Fall Under 1 ktco2/yr*

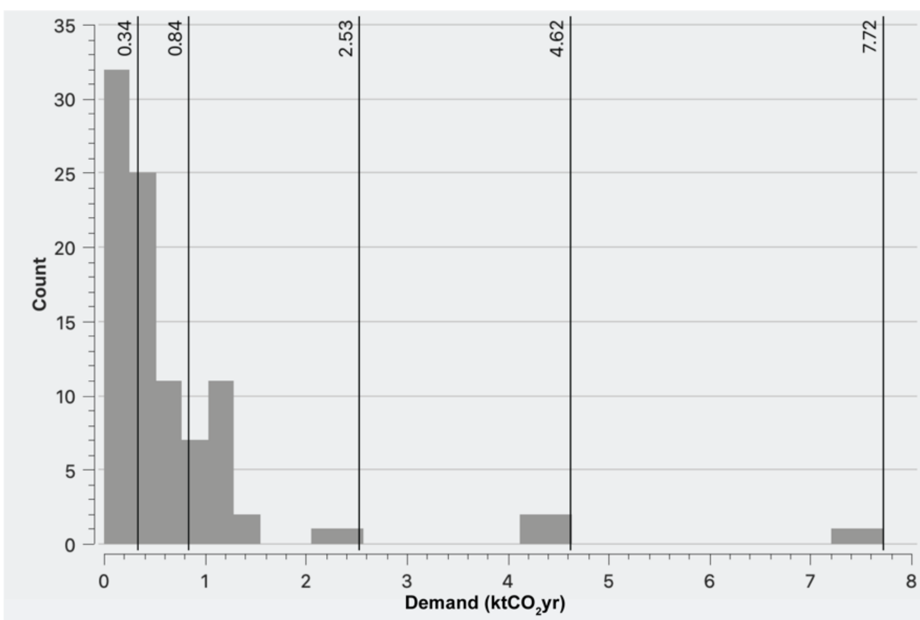


**Figure 4. Distribution of RMC plants by potential annual demand for CO_2 (kt/yr). The majority of plants fall under 1 $ktCO_2$/yr.*

The cumulative sink for CO_2 is quantified in column 2, with average weighted transport (via tanker trucking) listed in column 3. Naturally, as the service area radius is broadened, cumulative sink potential increases as more RMC facilities fall within scope. Likewise, the average weighted cost of transport increases due to increased transport distance from the blue hydrogen facility. Importantly, Table 4 shows that the service area should be extended to at least 75 miles to ensure 45Q compliance (i.e., that 25,000 tCO_2/yr are contracted into beneficial reuse opportunities) and qualification for tax credits. To illustrate the impact of 45Q on the CO_2 breakeven price, or the minimum resale price for CO_2 to turn a profit of zero, column 4 shows the expected cost of capture, compression and transport without 45Q, and columns 5 and 6 show the calculated breakeven price for each service area, with and without 45Q, respectively. These results assume that RMC contracts within the confined service area are the only source of revenue from CO2 utilization (i.e., no other sinks are sought).

In column 6, the breakeven price for CO_2 crosses the \$100/t threshold at the 75-mile service area. Incidentally, full service to this area would allow 45Q credits to be applied; hence, the appropriate breakeven price for CO2 shifts to column 5. Here, at 75-miles, the CO_2 breakeven price is \$71/t. As larger service areas are considered, the breakeven price for CO_2 continues to drop and reaches a minimum at the 175-mile service area. This suggests that diminishing returns are to be expected for delivery and partnerships beyond this area. However, in a real-world scenario, the likelihood of gaining contracts with every RMC within a service area is unrealistic; thus, a true analysis must consider case-by-case interest to assess the actual potential in any given service area.

Table 5 shows the implications of a service area assuming two scenarios based on a ratio of contracts to facilities: 50% contracted and 25% contracted. These results reveal two important factors: 1) there are greater transport costs incurred to achieve the same contract volume and, more importantly, to qualify for 45Q, and 2) the CO_2 breakeven price becomes much greater at close distances because the SAM (cumulative demand) is much smaller, meaning *if* RMC plants represent the only sink for captured CO_2, a much larger service area is required to drive the breakeven price down to a competitive territory. For the purpose of this analysis, \$50/tCO_2 is used as a benchmark for CO_2 purchase price in non-food/beverage-based reuse.[45]

[45] ISBT grade CO_2 is 99.9% purity and can command a higher market price.

Table 5. Service Area Analysis and Breakeven Price for Delivery of Captured CO2 to Ohio-based RMC Plants assuming: 50% Of RMC Contracts Fulfilled and 25% of RMC Fulfilled.

	50% contract scenario			25% contract scenario		
Service Area (mi.)	Cumulative demand ($ktCO_2$/yr)[a]	CO_2 breakeven price (w/45q) ($/t$CO_2$)	CO_2 breakeven price (w/o 45q) ($/t$CO_2$)	Cumulative demand ($ktCO_2$/yr)[b]	CO_2 breakeven price (w/45q) ($/t$CO_2$)	CO_2 breakeven price (w/o 45q) ($/t$CO_2$)
10	0.7	3418	3453	0.4	6861	6910
25	2.6	935	973	1.3	1891	1950
50	6.0	398	441	3.0	813	887
75	15.5	151	202	7.8	312	408
100	22.9	104	159	11.4	214	323
125	28.5	86	144	14.3	173	292
150	33.1	77	138	16.5	152	280
175	35.8	73	137	17.9	143	277
200	39.3	71	138	19.7	134	280

[a] 45Q tax credits apply at the 125-mile service area and beyond.

[b] 45Q tax credits do not apply within the 200-mile service area.

4.2 Small Scale Hydrogen Production: 500 kgH2/day

4.2.1 Single Source to Single Sink: EOR or Geological Storage

At 500 kgH_2/day (reported earlier as the volume required by SARTA), a blue hydrogen facility will capture approximately 1000 tCO2/yr. This captured CO_2 could be delivered to an EOR facility for injection or to a geological storage site. There are several differences between these two scales that are worth noting:

- the cost of CO_2 capture and compression jumps from \$24/tCO_2 to approximately \$50/tCO_2 for a 500 kgH_2/day facility. This is due to economy of scale limitations on capture equipment.
- due to the smaller volume of transport, small scale facilities do not qualify for 45Q.
- transportation costs via tanker trucking are expected to be comparable, as costs are less sensitive to scale[46] and more dependent on distance transported.

[46] There is a threshold between 500 kt and 750 ktCO_2/yr volume where pipelines become more economical than trucking. For much greater volumes, the discrepancy of cost becomes even more important and favorable to pipeline; thus, there is an argument for scale on transport economics. However, at very small scales, trucking is the only economic option and scale becomes far less important than distance.

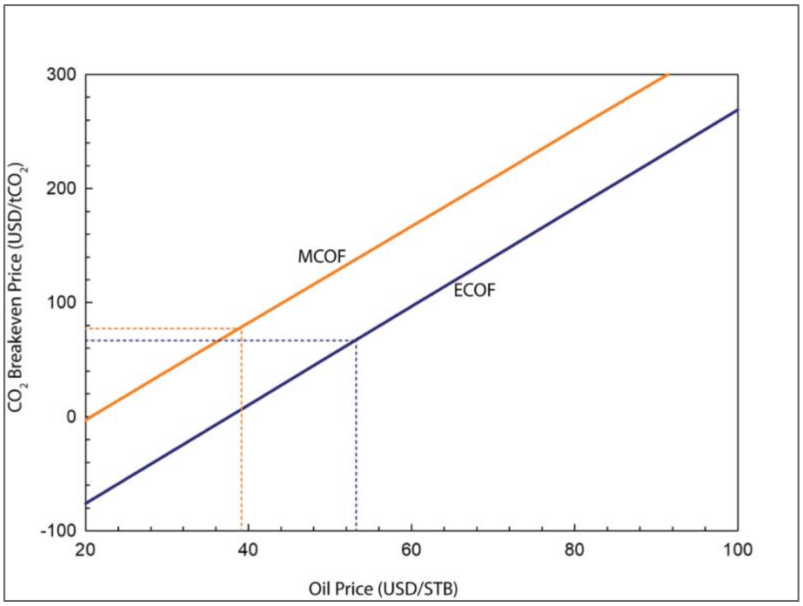
As before, an analysis of the total cost to deliver and inject CO_2 into three possible EOR fields is analyzed, and results are reported in Table 6. Pipeline is not considered here due to economies of scale and physical limitations with small volume pipeline transport. The total EOR/storage cost is considered identical since there are no applicable tax/credits, but could differ in reality due to discrepancies in field preparation, injection, monitoring and verification, and post-injection site care costs. Due to the increased cost of capture and compression and lack of tax credit application, the total cost is \$40-\$50/tCO_2 greater at small scale facilities. Accordingly, as indicated in the CO_2 breakeven analysis shown in Figure 5, these higher prices for CO_2 from small-scale facilities necessitate a crude oil price greater than \$39 and \$53/STB at the Morrow Consolidated Oil Field and East Canton Oil Field, respectively to run EOR at a net profit.

Table 6. Breakdown of CO2 Delivery and Injection Costs from Small Scale Hydrogen Production at SARTA to Three Oilfields*

Destination	Distance (mi.)	Capture and Compression ($/tCO2)	Trucking ($/tCO2)	Total EOR/Storage ($/tCO2) with injection
ECOF	22	50	6	67
MCOF	83	50	17	78
Core Energy	450+	50	82	143

**the non-active EOR fields of ECOF and MCOF in Eastern and Northern Central Ohio, respectively, and the active fields operated by Core Energy in Northern Michigan.*

Figure 5. CO2 Breakeven Price as a Function of Oil Price for EOR in the MCOF (Orange) and ECOF (Blue) Fields using CO2 Derived from Small Scale Blue Hydrogen Production*



**Due to the increased cost of production, EOR in the MCOF can be profitable if the cost of crude oil is above 39 USD/STB, whereas the cost must exceed 53 USD/STB in the ECOF.*

4.2.2 Single Source to Single Sink: Ready Mix Concrete

The histogram in Figure 4 shows that the majority of RMC plants are under 1 ktCO_2/yr in demand. This pairs well with small-scale blue hydrogen production and could serve as logical source-sink relationships. Given the scale of captured emissions, it is entirely likely that a single RMC partner can absorb the entirety of captured CO_2 from a refueling-scale blue hydrogen facility. Further, there may be reduced logistics associated with co-locating a refueling scale H_2 plant and RMC facility, as both would benefit from strategic siting in highly populated and/or easily accessible areas, e.g., at or near city transportation hubs. Likewise, the economics of a single source-sink pairing make the revenue-compensation model more directly calculable in terms of minimum risk and contingency scenarios. For example, a refueling (500 kgH_2/day) plant placed – say – 10 miles from an RMC facility under contract for purchase of the entirety of emissions associated with blue hydrogen production would yield a CO_2 breakeven price equivalent to the total cost of capture/compression and transport (in this example, ca. \$60 – 65/tCO_2).

The National Renewable Energy Laboratory (NREL) outlines 4 key lessons from the California's successful deployment of hydrogen refueling stations:[47]

1. Quantify FCEV market and automaker commitments.
2. Establish financial support mechanisms for hydrogen refueling station investments.
3. Establish FCEV market support mechanisms.
4. Implement station network planning tools.

As described earlier, SARTA's FCEB fleet, each requiring a daily fueling of 30-35 kg H_2/day, projects to need a refueling station with a capacity of at least 480 kg H_2/day. While a single 500 kg H_2/day facility would satisfy immediate demand, the California Hydrogen Highway initiative has highly recommended double redundancy and reducing system utilization to part-time. This operation could be advantageous with intermittent energy sources like wind or solar but may prove difficult in small scale SMR facilities which will operate at elevated temperatures. Redundancy is designed to meet unanticipated system outages, though on-site storage of H_2 may obviate this need.

One possible pathway to H_2 expansion might operate under the following three-phase initiative:

> Phase I: a single 500 kgH_2/day blue hydrogen facility located in Canton, and the captured CO_2 is delivered to a single RMC.
> Phase II: addition of three 500 kgH_2/day facilities strategically placed at major transportation hubs, identified by an annual average daily truck count of at least 15,000 trucks per day.
> Phase III: deployment of additional facilities to extend service along major highway segments with a first target of remaining high-volume segments (>15,000 trucks per day) and a second target of lesser volume segments (between 8,000 and 15,000 trucks per day).

Liu et al. estimate that with a 10% fuel cell electric truck (FCET) penetration by 2025, the intra-zone freight flow in Ohio will require upwards of 10,000 kg H_2/day around major city hubs and closer to 30,000 kg H_2/day in regions outside major city limits, due to the greater average hauling

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[47] Melaina, M., B. Bush, M. Muratori, J. Zuboy and S. Ellis, 2017. "National Hydrogen Scenarios: How Many Stations, Where, and When?" Prepared by the National Renewable Energy Laboratory for the H2 USA Locations Roadmap Working Group. http://h2usa.org/sites/default/files/H2USA_LRWG_NationalScenarios2017.pdf.

distance.[48] Inter-region hauling largely along interstates like I-80/I-90, I-76 , I-70 and I-71 naturally shows greater trucking traffic but also has a greater proportion of trucks passing through, as FCET can travel 300 mi (conservatively) to 750 mi on a single tank, assuming a fuel economy of 10-12 miles per kg H_2. If an FCET penetration of 10% is assumed, and 10% of these FCET require refueling in the area, this corresponds to roughly 10,000 kg H_2/day demand assuming a 60 kg H_2 per FCET capacity.

Figure 6 illustrates the annual average traffic count for trucking in Central/Northern Ohio, as well as local RMC facilities. This gives a sense of the potential demand for H_2 in the region, and where to strategically place refueling stations in the case of expansion. Phase 1 is designed to demonstrate proof-of-concept of a refueling-scale blue hydrogen station and – importantly – a working contractual agreement with a second party off taker for the captured CO_2. The metric of success in a potential Phase I deployment is largely contingent on a) the levelized cost of H_2 generation after consideration of any credits or revenue earned from CO_2 capture and resale to an RMC plant and b) the carbon intensity of H_2 generation. These metrics are compared against green hydrogen production cost and carbon intensity in section 5.1.

Phases II and III can be evaluated as more reliable estimates for FCEV hydrogen demands materialize, either for SARTA's internal needs or as an economic opportunity to meet area demand. Typically, hot spot analyses can reveal spatial trends in demand, and promising locations for expansion can be revealed through assessment of several siting factors including source-sink proximity. In the hypothetical deployment scenario considered here, strategic placement of Phase II plants follows the average annual daily traffic count for trucks along major highway segments. This metric is used as a hot-spot proxy as it is logical to expose a filling station to as much trucking traffic as possible. Alternatively, as many FCET or FCEB require a daily refueling and would likely refuel before commencing daily transport routes, it may be logical to co-locate refueling stations with major distribution hubs. Either way, as evidenced in Figure 6, the distribution of RMC plants is sufficient to provide flexibility in refueling station siting.

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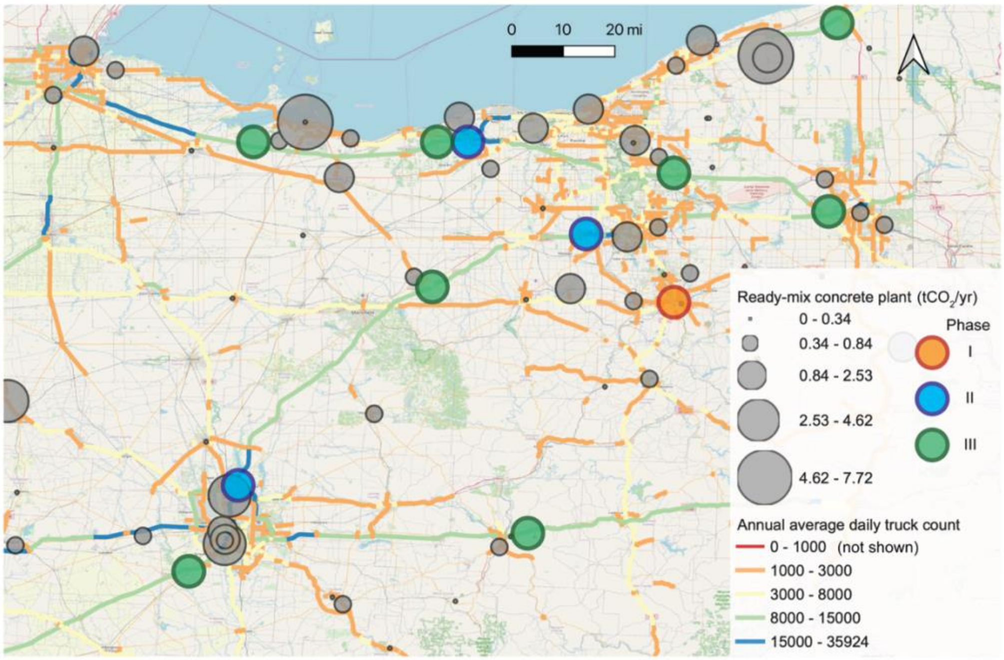
[48] Liu, Nawei, Fei Xie, Zhenhong Lin, and Mingzhou Jin, 2019. "Evaluating national hydrogen refueling infrastructure requirement and economic competitiveness of fuel cell electric long-haul trucks." Mitigation and Adaptation Strategies for Global Change. doi: 10.1007/s11027- 019-09896-z.

Figure 6. Potential Three-phase Deployment Plan for Expansion of 500kgh2/day Refueling Stations*



**Phase I representing a single proof-of-concept install centered in Canton, with Phases II and III designed to strategically expand to meet demand along high traffic highway segments.*

5.0 Strategies for SARTA

5.1 Strategy for Optimizing Costs of Generating Hydrogen and Capturing Carbon

The levelized cost of H_2 ($/kg) is lower for large centralized H_2 plants than it is for smaller refueling station scale facilities for two primary reasons: economies of scale work against small scale SMR operation, and larger facilities have access to lower cost major inputs, namely electricity and natural gas (for example, small facilities may pay a utility rate of around $8/MSCF for natural gas, while larger facilities can access city-gate pricing of close to $4/MSCF). Natural gas is also likely to be delivered under higher pressure at a large facility, reducing the costs of compression. The cost of H_2 is initially considered with CO_2 captured, compressed and vented – a cradle-to-gate approach that will help illustrate the impact of downstream decisions with regards to CO_2. The levelized cost of hydrogen generation within these boundaries is $1.41/kgH$_2$ and $3.54/kgH$_2$ at large and small-scale plants, respectively.

The next step is to consider the impact of sink choice on both levelized cost of hydrogen and overall fuel carbon intensity. These results can be compared against green hydrogen production at both scales. For this analysis, the cost of hydrogen produced through alkaline electrolysis is \$4.16/kgH_2 and \$6.23/kgH_2 for large and small scales, respectively.[49] The carbon intensity of green hydrogen production is entirely tied to the source of power. For renewable sources, lifecycle emissions are largely tied to the material embodied in the renewable energy source and storage medium, and to a far less extent the embodied emissions in the electrolyzer components and equipment. Assuming best-in-class capacity factors for solar and wind (eq., 35.2% and 52% CF, respectively), utility scale PV with lithium ion battery storage results in a carbon intensity of 49 gCO_2e/kWh,[50] while wind coupled to lithium ion battery storage results in a carbon intensity of 26 gCO_2e/kWh. Importantly, a green electrolysis operation will want to avoid grid power whenever possible;[51] thus, storage is a desired system component to ensure continuous operation of the electrolyzer. According to the *Lazard Levelized Cost of Storage Analysis* report, unsubsidized wholesale PV and storage commands a range of \$102 to \$130/MWh.[52] Assuming an average value of \$116/MWh for renewable energy and storage, the cost of green hydrogen production jumps to \$7.08 and \$7.43/kgH_2 for large and small scale facilities, respectively, with a carbon intensity of 2.5 kgCO_2e/kgH_2.

Alternatively, renewable natural gas (RNG) can be used in place of fossil-based natural gas as fuel and feedstock for SMR H_2 production. A 2014 NREL report shows that several Ohio counties, including Cuyahoga, Stark, Tuscarawas, Richland, Crawford, Wyandot, Franklin and Hamilton, have a total renewable methane potential in excess of 10,000 tonnes (each), which translates into at least 2,670 tonnes of H_2 potential for each county.[53] This total includes the collective contributions from landfills, wastewater treatment plants (WWTP), manure management, and industrial, institutional, and commercial organic waste. Landfills represent the largest contributor to RNG stock, and Stark County is identified as having the 8th greatest potential of any U.S. county at a net hydrogen potential of 9500 tonnes.

The next largest source of RNG is WWTP, with Cuyahoga county recognized as having the 14th highest potential of any U.S. county at approximately 5400 tonnes of hydrogen potential. Either source could be considered suitable to support a 500 kgH_2/day facility (ca. 170 tonne H_2 per year at 90% availability) for decades. However, neither source (nor the combined potential of both sources) is sufficient to fully support a single year of large-scale production. Further, RNG incurs

[49] This assumes an electricity cost of \$60/MWh for large scale facilities and \$92.9/MWh at small scale facilities. SARTA's 2020 all in cost of power is similar to the small scale cost.
[50] gCO_2e/kWh = total mass (grams) of direct, indirect and embodied CO_2 equivalent emissions (considering all emissions and correcting to the GWP of CO_2) per kilowatt hour of electricity generated.
[51] The Ohio grid has an average carbon intensity of 808 gCO_2e/kWh.
[52] Lazard's Levelized Cost of Storage Analysis, Version 5.0. Accessed from: https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.
[53] NREL, 2014. Renewable Hydrogen Potential from Biogas in the United States. National Renewable Energy Laboratory, Golden, CO.

a high premium, with some reports indicating a cost of near \$15/MSCF.[54] This higher cost can be considered a trade-off, as RNG produces a much lower carbon footprint in generating H_2 without capturing emissions (although carbon could still be captured).[55] The impact of replacing fossil natural gas with RNG depends on the source. Typically, landfill and Waste Water Treatment Plants natural gas have a (C.I.) carbon intensity of 46.42 and 19.34 gCO_2e/MJ, respectively (compare to fossil natural gas with a C.I. of 78.37 gCO_2e/MJ). [56] Other sources, such a municipal solid waste or dairy farming, can lower the footprint considerably further; however, these sources are more diffuse and collection at scale proves difficult and costly. <u>The analysis below thus considers only landfill or WWTP sourced RNG, and only for the small-scale operation.</u>

For large scale H_2 production, three end uses are considered: geological storage, EOR, and use in ready-mixed concrete (RMC). For storage, the 45Q tax credit is applied as well as transport and injection costs. It is assumed that the entirety of CO_2 injected can be deducted from the H_2 production lifecycle emissions. For EOR, the 45Q credit is applied as well as costs for transportation and injection. Here, using a baseline NETL case for CO_2-EOR, every 14.4 $MtCO_2$ purchased results in a net storage of 10.5 $MtCO_2$;[57] thus every tonne of CO_2 delivered results in 0.73 tCO_2 deducted from the H_2 production lifecycle emissions. Unlike for storage, EOR operators will pay for CO_2. Since there are two viable EOR locations proximal to the large-scale H_2 facility, two separate EOR costs are determined. We use here the breakeven cost analysis from earlier to assign a purchase price of \$20/tCO_2 delivered to the East Canton Oil Field and \$40/tCO_2 delivered to the Morrow Consolidate Oil Field. For delivery to RMC facilities, the 50% contract scenario is assumed, using the full 200-mile service area. According to Table 5, this resulted in a breakeven price of roughly \$71/tCO_2. However, in this scenario, a purchase price is deliberately set under (at \$50/tCO_2) to illustrate the incremental cost of H_2 production. While all emissions delivered to an RMC plant can assume to become embodied as a solid carbonate (i.e., permanently stored), only the fraction of CO_2 contracted to RMC plants counts against the H_2 production lifecycle emissions; the remaining CO_2 is assumed to be vented. Results are shown in Table 7.

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[54] *See* J. Cole, CALSTART report, note 1.
[55] It is technically possible to do both: use RNG and capture exhaust emissions. This scenario is not investigated in this report.
[56] Argonne, 2019. The Greenhouse gases, Regulated Emissions, and Energy use in Transportation Model (GREET). Argonne National Laboratory, Lemont, IL. https://greet.es.anl.gov
[57] NETL, 2010. An Assessment of Gate-to-Gate Environmental Life Cycle Performance of Water-Alternating-Gas CO_2-Enhanced Oil Recovery in the Permian Basin. National Energy Technology Laboratory, Pittsburgh, PA, USA.

Table 7. Comparison of Cost and Carbon Intensity for Various Large-Scale Hydrogen Production Options.

Approach	Cost ($/kg H_2)	Carbon Intensity ($kgCO_2e/kgH_2$)
SMR: on-site, no capture	1.24	8.98
SMR: onsite with capture (blue)		
- with geological storage	1.27	2.44
- with EOR/ECOF	1.22	4.17
- with EOR/MCOF	1.16	4.40
- with RMC	1.42	6.39
Electrolysis (green) – no grid	7.08	2.58

When compared to a baseline SMR plant without carbon capture, only pathways involving EOR result in lower H_2 production costs. This is the impact of the stacked 45Q tax credit and CO_2 resale revenue. The lowest cost option is CO_2-EOR, but the lowest carbon footprint is realized in the geological storage option. Further, the storage option carries fewer risks as storage does not rely on any market mechanisms to operate. All options yield far lower production costs than the green production route. To bring the green production route into cost competitiveness with blue production and storage (it is already similar in C.I), the levelized cost of renewable electricity and storage would have to approach $10/MWh. The elevated C.I. of the RMC case is due to venting of non-contracted CO_2. In reality, additional sink opportunities are likely to be sought to off take the remaining captured CO_2. This would effectively lower the RMC C.I. since that scenario would longer be burdened with vented emissions. Importantly, all pathways lead to a reduced carbon footprint over the baseline case.

A similar analysis can be applied to small scale hydrogen production. Using the values reported above for baseline green and blue (cradle-to-gate) H_2 production, three end uses are considered: small-scale delivery to storage, EOR, and RMC plants. Two key differences apply in the small scale scenario: 1) there is no 45Q tax credit, thus the only source of revenue comes from sales to EOR or RMC, using the same purchase prices outlined in the large scale example, and 2) all CO_2 is expected to be contracted in the small scale RMC scenario, which drives down the transport cost and overall carbon intensity. Additionally, an RNG scenario is presented for an SMR plant without carbon capture. Results for the small-scale analysis are shown in Table 8 and are presented against a baseline case where hydrogen is produced off-site via SMR and delivered via trucking in the form of liquid hydrogen (LH_2).

Table 8. Comparison of Cost and Carbon Intensity for Various Small-Scale Hydrogen Production Options.

Method	Cost ($/kg H_2)	Carbon Intensity ($kgCO_2e/kg\ H_2$)
SMR: delivered via LH_2[a]	5.93	9.81[b]
SMR: onsite, no capture	3.22	8.98
SMR: RNG, no capture	4.49	2.22 – 5.32[c]
SMR: onsite with capture (blue)		
- with geological storage	3.65	2.44
- with EOR/ECOF	3.52	4.17
- with EOR/MCOF	3.47	4.40
- with RMC	3.27	2.44
Electrolysis (green) – no grid	7.43	2.58

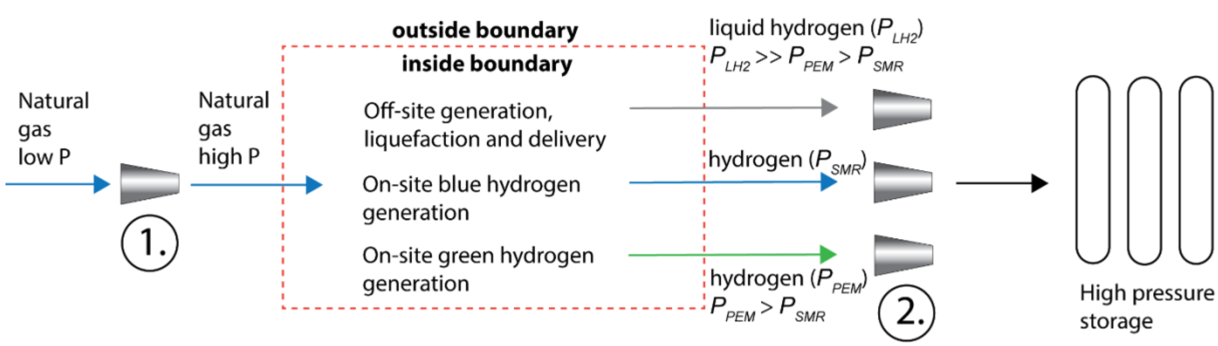
[a] This hydrogen is compressed and liquified in Sarnia, Ontario, Canada, and delivered ca. 270 miles in LH_2 tanker trailers to SARTA. *Importantly, this method of delivery arrives under pressure, and little or no additional on-site hydrogen compression is required for storage. This cost needs to be accounted for in a true apples to apples comparison.*

[b] The incremental carbon footprint assumes negligible boil-off losses at the Sarnia trailer refill and during transit, and emissions of 220 gCO_2e/tonne/mile due to fuel consumption.

[c] The lower bound represents WWTP RNG at 19.34 gCO_2e/MJ and the upper bound represents landfill RNG at 46.42 gCO_2e/MJ.

In order to draw meaningful comparisons from Table 8, it is necessary to discuss the boundary conditions used to estimate hydrogen production costs. In a true apples-to-apples comparison of production costs, all upstream and downstream costs would be considered, ultimately leading to a delivered-to-the-bus cost of hydrogen. But each location, including SARTA's location in Canton, Ohio, have different circumstances that require different technologies and mechanisms of generation (upstream), storage and delivery (downstream). As a result, without detailed engineering of the different strategies, *it is not possible to match upstream and downstream conditions for applications.* This point is illustrated schematically in Figure 7.

Figure 7. Boundary Conditions Applied to the Comparison of Hydrogen Production Costs.



**Two key points, labeled 1. and 2., represent areas where incremental costs and/or cost discrepancies may occur which complicate the side-by-side comparison of hydrogen production costs.*

At point 1 in Figure 7, the upstream compression of natural gas from standard distribution pressure (typically 50 – 70 psi) to operating pressure (*ca.* 200 psi) are likely to add capital and operating expenses to the blue hydrogen route on the order of \$0.50 – 0.75/kg H_2.[58] Likewise, the incremental energy required for compression power (approximately 11 kW) will result in additional CO_2 emissions depending on local grid intensity (estimated at +0.43 $kgCO_2e/kgH_2$ at a grid intensity of 0.808 $kgCO_2e/kWh$). The need for on-site compression could be obviated by the installation of a high-pressure pipeline; however, the viability of high-pressure pipeline installation is contingent on proximity to high pressure transmission lines, and the proposed refueling station at SARTA's facility would not qualify. This underscores an important additional consideration when siting potential refueling station locations.

Point 2 in Figure 7 represents the downstream (outside of boundary) pressure of hydrogen prior to compression for on-site storage. Generally, green electrolysis via PEM has a higher outlet pressure (P_{PEM}) than production from SMR (P_{SMR}). This results in decreased power required for hydrogen storage when compared to the blue route (31 and 56 kW respectively) leading to slightly lower downstream costs and emissions. In the incumbent pathway involving delivery of liquified hydrogen, the hydrogen is already at significant pressure (P_{LH2}) such that $P_{LH2} >> P_{PEM} > P_{SMR}$. The advantage of liquid hydrogen delivery is that the pressurization of hydrogen has already been accomplished, though there are risks associated with boil-off losses during delivery.

This study assumes that downstream compression conservatively adds \$1.30 – \$1.50/kgH_2 to the production cost,[59] with the lower bound assigned to green production. Likewise, though compression costs are non-trivial, on-site compression costs are not expected to exceed the cost difference between blue hydrogen and delivered liquid hydrogen. In summary, though consideration of the above boundary conditions will necessarily narrow the cost parity of the systems under study, the overall cost trends are expected to remain intact.

Based upon this understanding, it appears that the least cost, near term option for SARTA may be onsite SMR without carbon capture.[60] However, the carbon intensity of this option is high (nearly 9 $kgCO_2$ emitted per kgH_2 produced) – higher than any strategy but the status quo (excluding compression). The status quo (baseline) scenario incurs higher costs due to delivery. Despite the long transport distance (approximately 540 miles round-trip), trucking transport

[58] Based upon a compressor power of 11-12 kW, electricity cost of \$90/MWh, and compressor CAPEX of \$400,000 - \$600,000.
[59] Assumes no spare compressors. Compression power calculated as 55 – 75 kW assuming compression to 500 bar for SMR and PEM, respectively. Other assumptions follow as reported in footnote 58.
[60] This is consistent with the findings from the onsite hydrogen generation study undertaking by CALSTART, referenced in note 1.

costs make-up less than 5% of the overall delivery cost.[61] The majority of delivery cost is attributed to liquefaction capital and operating expenses incurred at the SMR facility. Of course, without liquefaction, transportation costs would be considerably higher, so the two costs cannot be unwound. Long-distance delivery, however, adds significantly to SARTA's higher carbon footprint: trucking delivery via diesel tractor-trailers adds roughly 0.22 $kgCO_2e$ for every tonne-mile[62] transported.

The next lowest cost option is delivery to an RMC facility. As stated earlier, the scales match well in this source-sink pairing, and the economics and low carbon intensity make it an ideal option. Further, as illustrated in Figures 3 and 6, there are an abundance of opportunities to match the supply of captured CO_2 from a blue hydrogen plant with demand for CO_2 among RMC facilities, and in most cases only a single contract is needed to absorb all captured CO_2. This is reflected in the low C.I., where all CO_2 is permanently stored in carbonate form and can thus be deducted entirely from the H_2 production lifecycle emissions.

Unlike before, the geological storage case adds to the H_2 production costs; in the absence of 45Q, there is no financial incentive to store CO_2. Even so, the carbon disposal costs are relatively modest: when considering the amount of CO_2 captured per year in a blue hydrogen plant (in this case, roughly 1,040 tCO_2) versus the annual H_2 generation (1.7 million kgH_2), every dollar incurred for CO_2 treatment, handling and disposal results in 0.6 cents per kg in additional H_2 production costs. The comparatively small tCO_2/kgH_2 ratio buffers against large swings in production cost.

Either EOR field discussed herein could act as a sink, with revenue from CO_2 purchase effectively lowering the H_2 production cost, even in the absence of 45Q. However, as described in Section 4.2, the increased production cost of CO_2 in small-scale facilities means smaller margins on resale compared to H_2 from large facilities. This could translate to additional risk from the viewpoint of CO_2-EOR operators, particularly in the event of a non-rebounding price on crude oil.

The cost of green hydrogen is non-competitive at this scale, based upon the electrolysis technology and the cost of electricity in 2020, although there is greater cost parity than would be realized for the large-scale blue hydrogen SMR facilities. To become cost competitive with small-scale blue hydrogen, the levelized cost of renewable electricity and storage would have to approach \$30-\$40/MWh, which is possible on site at nuclear or large scale renewable generation facilities, where distribution and other electricity charges can be avoided.

[61] Trucking costs include fuel cost, license and insurance, labor costs, tire and maintenance costs, trucking lease costs and miscellaneous costs.
[62] A tonne-mile represents the transport of one tonne of material a distance of one mile.

Use of renewable natural gas (RNG) adds roughly \$1/kgH_2 to production costs. As described earlier, Northeast Ohio is recognized as having ample RNG to support small-scale H_2 production. However, the *availability* of RNG is subject to the nature of incumbent contracts (if existing). Assuming that RNG can be contracted to small-scale blue H_2 facilities, this option should be considered competitive in the region as it can produce H_2 at comparable (and depending on feedstock, lower) carbon footprint to the blue H_2 options described above. Further, the cost premium of \$1/kgH_2 could be viewed as a cost of risk mitigation, as RNG facilities do not have to capture (and dispose of) carbon emissions. Arguably, to be truly green, the SMR facility should be tied to *new* RNG production, otherwise it would just displace an existing third-party sale for the RNG.

Finally, it should be noted that currently there is no social cost ascribed to emitting carbon dioxide in the United States. That is likely to change, as the climate change crisis continues to accelerate. Tables 7 and 8 can be updated by putting a cost (or value) on the carbon intensity column, thereby arriving at a more readily understood cost of hydrogen. As it stands, SARTA, other transit agencies and hydrogen refueling developers are left to balance costs against carbon intensity based upon each organization's own internal social commitments and budgets. It must be recognized, however, that the best technology may well change if and when social costs of emitting carbon dioxide becomes fixed.

5.2 Other Considerations

Two thirds of the cost of hydrogen today comes from transportation and refueling infrastructure. Long haul hydrogen transportation is costly and carbon intensive. As hydrogen markets mature, we may see more localized large scale SMR facilities sufficient to support refueling stations like that located at SARTA. In the meantime, refueling infrastructure will have to rely on small-scale, on-site SMR.

SMR developers will look for a commitment long enough to recoup the cost of the facility at an acceptable rate of return. This will likely be in the form of a multi-year, full requirements contract with the owner of a hydrogen vehicle fleet, with some possible take-or-pay attributes. It probably will also require a multi-year, full requirements contract with a natural gas provider. If the fleet owner is also interested in reducing its carbon footprint, it can add, for a modest cost, technology to capture carbon dioxide emissions. The more significant cost will be in disposing of that carbon dioxide. The best strategy is for the SMR facility to find someone to transport and use the carbon dioxide in a manner that sequesters it. The costs for doing this can be passed through to the fleet operator on a per kg of hydrogen basis.

Tying carbon capture and use to SMR facilities adds some complexity to the economics of hydrogen generation and delivery. SMR developers will likely have to manage multiple, long term take-or-pay and transportation contracts. This adds operating costs and risk. Industrial gas companies know how to manage these costs and risks. Further, the carbon capture system can be retrofitted to the SMR facility at a later date, after carbon dioxide markets have been secured. At some point, the climate crisis will lead society to implement a cost for emitting carbon. When it does, carbon use markets will become more readily available, and the economics of carbon capture more secure.

6.0 Summary and Conclusion

Refueling infrastructure for early adopters of hydrogen vehicles finally appears to be imminent. There is a consensus from long haul trucking and transit agencies that hydrogen fuel cell electric vehicles are the most cost-effective strategy for transitioning to low or zero emission fuels. Refueling stations for hydrogen fuel cell vehicles will require careful planning to ensure costs are low and that carbon dioxide emissions are minimized.

Until such time that refueling stations are commonplace, the most likely scenario for mitigating both costs and carbon intensity is local, on site hydrogen generation at the refueling stations. An analysis of the state of current technologies suggests that the most cost-effective strategy for local hydrogen generation near term is use of steam methane reforming. Carbon emissions can be most cost effectively mitigated through either capture and use (blue hydrogen) if a local market for the carbon dioxide can be found, or through using renewable natural gas. However low renewable power prices, together with improving electrolyzer technologies, promise the availability of cost-effective green hydrogen in the medium to long term.

SARTA, with its fleet of 17 regular and paratransit buses, appears to have a large enough hydrogen load (500 kg/day) to be able to cost effectively generate hydrogen on site through steam methane reforming, thereby reducing both cost and carbon emissions. However, it also appears that it could cost effectively capture carbon dioxide from the natural gas reforming process and sell it to local companies who can use it in a process that would sequester it permanently. While the costs of such “blue hydrogen” are not as low as making hydrogen and venting the carbon dioxide, it is still comparable to the status quo – shipping the hydrogen from Ontario, Canada. Further, this is only because there is currently no social cost placed on this practice. That is likely to change, as the world faces an escalating climate crisis. Indeed, once a social cost of carbon emissions is established, the green renewable natural gas or hydrogen/electrolyzer options may quickly become the most cost-effective strategy.

Authors

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Appendix

List of Abbreviations

BEV	battery electric vehicle
bbl	barrel
blue hydrogen	hydrogen sourced from steam methane reformation with carbon capture
CAPEX	capital expenditures
CCU	carbon capture and utilization
CCUS	carbon capture, utilization and/or storage
CF	capacity factor
CH4	methane
C.I.	carbon intensity
CNG	compressed natural gas
CO2	carbon dioxide
CO2e	carbon dioxide equivalent
dge	diesel-gallon-equivalent
ECOF	East Canton Consolidated Oilfield
EOR	enhanced oil recovery
FCEB	fuel cell electric bus
FCET	fuel cell electric truck
FCEV	fuel cell electric vehicle
GHG	greenhouse gas emissions
green hydrogen	hydrogen sourced from renewably-powered electrolysis
GREET	greenhouse gases, regulated emissions and energy use in transportation
Gt	gigatonne, or 1 billion tonnes
ICEV	internal combustion engine vehicle
IRENA	International Renewable Energy Agency
ISBT	International Society of Beverage Technologists
kg	kilogram, or 1000 grams
km	kilometer, or 1000 meters
kWh	kilowatt hour, or 3.6 MJ
LCA	lifecycle analysis
LH_2	liquid hydrogen transport
LHV	lower heating value
MCOF	Morrow Consolidated Oilfield
MJ	megajoule, or 1 million joules
MRCSP	Midwest Regional Carbon Sequestration Partnership
MSCF	thousand standard cubic feet
Mt	megatonne, or 1 million tonnes
OPEX	operating expenditures

RMC	ready mix concrete
RNG	renewable natural gas
SARTA	Stark Area Regional Transit Authority
SAM	serviceable addressable market
short ton	2,000 lb or 0.907 tonne
SMR	steam methane reforming
STB	stock tank barrel
TEA	technoeconomic analysis
tonne	1,000 kg or 2,204 lb
tonne-mile	the transport of one tonne of material one mile
WWTP	waste water treatment plant