Applied Energy 280 (2020) 115974

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Energy and economic assessment of distributed renewable gas and electricity generation in a small disadvantaged urban community

Rochelle E. Silverman, Robert J. Flores *, Jack Brouwer

Advanced Power and Energy Program, University of California, Irvine, CA 92617, United States

HIGHLIGHTS

- Community scale biogas and renewable H_2 production is assessed.
- Use of renewable H_2 and biogas for electricity and fuels is examined.
- Using future costs, renewable fuel can be produced at $18 per MMBtu.
- Using future costs, electricity from these renewable fuels can reach $0.15 per kWh.
- 80% zero net community electricity can be met using these renewable fuels.

ARTICLE INFO

Keywords:
Renewable hydrogen
Community scale renewable fuels
Anaerobic digestion
Pipeline injection

ABSTRACT

A methodology for assessing the efficiency and economic viability of renewable gas generation and energy conversion to compliment residential PV is proposed and demonstrated for the 10,000 resident example community of Oak View in Huntington Beach, California. Renewable fuel production processes included in this work are (1) processing of community-produced organic fraction of municipal solid waste in an anaerobic digester, and (2) using solar generation paired with water electrolysis. Six pathways – three ending in natural gas pipeline injection and three ending in solid oxide fuel cell electricity production – were evaluated for each PV capacity scenario. The renewable fuel production potential based only upon waste from the studied community was determined to be 2400 MMBtu per year of renewable natural gas (RNG) from anaerobic digestion, and up to 28,500 MMBtu of hydrogen from electrolysis using only excess solar PV electricity. With current costs the levelized cost of energy (LCOE) for renewable fuel production is $40–203/MMBtu, depending upon the energy pathway and scale. The LCOE for renewable electricity production is $0.37–1.28/kWh. A combination of LCFS and tipping fees as low as $20 per ton can yield renewable fuel at $2 per MMBtu. Likewise, a tipping fee of $32 can lead to the production of renewable electricity at $0.18 per kWh. Using future costs, the unsubsidized cost of electricity can drop as low as $0.15 per kWh, and renewable fuel can be produced at $18 per MMBtu. If Low Carbon Fuel Credits exist in 2050, a tipping fee of less than $9 per ton can yield renewable fuel at $2 per MMBtu. On an energy basis, over 80% of the community electrical demand can be met through a combination of local solar PV, anaerobic digestion, and fuel cell operation (80% zero net electricity). In this scenario, solar PV meets 52% of the community electrical load, while excess solar production produces hydrogen that is passed through a fuel cell to meet 26% of the electrical load. The remaining 3% is met using RNG produced through anaerobic digestion using only organic waste from the studied community. This analysis indicates that the production of renewable fuel in the urban environment is currently not economically feasible but will become competitive with conventional energy in the future.

1. Introduction

Recent California laws and policies require boosts in energy efficiency [1], significant increases in renewable energy use [2], and a statewide decrease in greenhouse gas emissions [3]. Both energy efficiency and solar energy generation have been critical towards meeting current and future California energy and sustainability goals.

* Corresponding author.
E-mail address: rjf@apep.uci.edu (R.J. Flores).

https://doi.org/10.1016/j.apenergy.2020.115974
Received 26 May 2020; Received in revised form 28 September 2020; Accepted 2 October 2020
Available online 17 October 2020

Nomenclature

Superscripts and subscripts

CAP	capacity
capital	capital cost
e	electricity
NG	natural gas

Abbreviations

AC	axial compressor
AD	anaerobic digestion
AEC	alkaline electrolyzer
AFLEET	Alternative Fuel Life-Cycle Environmental and Economic Transportation
ATGO	anode tail gas oxidizer
BG U	biogas upgrading
CAISO	California Independent System Operator
CAPEX	capital expenditure
CB	centrifugal blower
CEC	California Energy Commission
CET	cathode exit temperature
CHP	combined heat and power
CLH	combination long-haul
CNG	compressed natural gas
CSH	combination short-haul
DER	distributed energy resource
EC	electrolysis
GGE	gasoline gallon equivalent
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation
GVWR	gross vehicle weight rating
HHV	higher heating value
ICE	internal combustion engine
LCOE	levelized cost of energy
Li-ion	Lithium ion
LPM	liters per minute
Max	maximum
MMBtu	million British thermal units
MPG	miles per gallon
MT	methanation
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OFMSW	organic fraction of municipal solid waste
OVWTS	Oak View waste transfer station
Pb-A	Lead acid
PEMEC	proton exchange membrane electrolyzer
PI	natural gas pipeline injection
PtG	power-to-gas
PV	photovoltaic
RNG	renewable natural gas
SCG	Southern California Gas Company
SOEC	solid oxide electrolyzer
SOFC	solid oxide fuel cell
SMR	steam methane reformation
SNG	synthetic natural gas
SULH	single unit long haul
SUSH	single unit short-haul
TBW	total body water
TDV	time-dependent valuation
tpy	tons per year
TS	total solids
US	utility-side
ZNE	zero-net-energy

Traditionally, both energy efficiency and solar have been supported through a combination of incentive and rebate programs [4–6]. Although successful, critics of such programs cite equity issues faced when attempting to implement energy efficiency and renewable energy measures in low income, urban, and/or multifamily communities [7]. In order to overcome these critiques, the concept of the community energy project or advanced energy community has emerged [7].

These energy projects can include community scale design of energy efficiency retrofits, district energy systems, combined heat and power, renewable generation, and community energy storage [8–12], with a particular focus on community solar [13]. As grid connected solar energy systems proliferate, challenges from handling excess solar generation must be dealt with [14]. Conventional methods for handling excess and unwanted solar output are to force the utility grid network to manage increasing use of net energy metering for small solar systems, use the excess energy to provide ancillary services, charge energy storage, or curtail the solar power. Considering the future need for a renewable fuel [15], another use of excess and/or cheap solar energy is through an electrolysis process to generate renewable hydrogen. Electrolysis of water to hydrogen using renewable energy, or power-to-gas (PtG), can be used to provide massive and long-duration (seasonal) energy storage to balance intermittent and inflexible renewable generation [16,17]. PtG includes any technology that converts electrical power to a gaseous fuel, usually hydrogen or methane. Hydrogen gas is the favored fuel produced by PtG technologies because it has a high energy density, is storable on large timescales, requires fewer steps to produce than methane, and produces no greenhouse gases when converted back to electricity [16].

It is easy to hypothesize the use of community solar to provide PtG would suffer from poor economies of scale, or that such a project would face not in my back yard – NIMBY – challenges [18]. One scenario in which both challenges could potentially be overcome is when the PtG electrolyzer is co-located with an existing industrial site, such as an urban waste transfer facility. The benefits of the system would be the introduction of the system into an industrial location, possible proximity to a community energy project, and the potential to develop renewable gas production using onsite organic waste. Previous studies have examined community energy projects that include optimizing waste handling and usage, including optimized recycling pathways [12,19–21]. Currently, there is little to no work presented in the literature on the colocation of PtG technology and waste transfer operations within an urban environment.

The current work examines this topic by considering the maximum renewable fuel production for a community that includes a waste transfer station. The particular community studied in this work is the Oak View neighborhood located in Huntington Beach California. Contributions of this work to the literature include:

- Performing a comprehensive literature review of the cost of environmentally friendly technologies and presenting the results as functions of project scale, and
- Proposing a generalizable methodology for assessing the energy efficiency and economic feasibility for a variety of distributed renewable gas and electricity generation systems in an urban setting

The community is home to approximately 10,000 residents [22], and includes a waste transfer station used to service Huntington Beach and other Orange County cities. Integration of both energy efficiency and solar energy resources have already been considered for this community [23]. The goal of this work is to determine the maximum potential

renewable energy production for this community when using PtG and waste-to-gas (WtG) production pathways, and to quantify the cost to produce this renewable energy. This work is organized as follows: Section 2 describes the different energy conversion pathways considered in this work, Section 3 describes the methodology for predicting renewable fuel production, Section 4 reviews the techno-economic characteristics of the considered technologies, Section 5 shows results from the analysis, and Section 6 presents conclusions.

2. Energy conversion pathways

The general system concept considered in this work is shown in Fig. 1. This concept shows (1) the use of excess renewable electricity to produce hydrogen via electrolysis (EC), and (2) the use of residential organic solid municipal waste to produce methane gas via anaerobic digestion (AD). For both pathways, the renewable fuel can be stored for later conversion to electricity, or sold to the local gas utility through pipeline injection (PI). In the case of electricity conversion, only solid oxide fuel cell technology is considered due to high electrical efficiency.

Considering these two options, six energy paths were developed for consideration in this work. Fig. 2 contains flowcharts of energy flow pathways through the Oak View community for each path considered. All six paths produce either RNG or electricity. Odd numbered paths terminate with RNG injection into the natural gas grid, and even numbered paths conclude with electricity generation via SOFC. Table 1 summarizes the technologies used in each path. Methanation was also considered. However, hydrogen production was not large enough in any scenario to accurately calculate methanation costs. This study assumed an electrolysis efficiency of 72%, a methanation efficiency of 80%, and an SOFC electrical efficiency of 60%.

The final pathway considered in this work assumes that AD is not locally adopted, but the organic waste is diverted to a preexisting digester in a different community. In this case, the cost of trucking the waste and paying a tipping fee must be weighed against potential revenue from generating renewable fuel. This option is considered as the final scenario as interviews with waste transfer station operators indicated that this path was most likely to occur.

Note that gasification of organic waste and methanation of renewable hydrogen were both originally considered. Despite being able to produce a hydrogen rich stream, gasification was eliminated from consideration after discussions with waste transfer station operators due to the quality and moisture content of the waste feedstock. Methanation was omitted due to a reduction in renewable fuel energy, and, more importantly, the renewable hydrogen production results are small relative to the capacity of methanation systems reported in the literature [24–27].

3. Methodology

In order to accomplish the goal of evaluating the renewable fuel energy potential for the design area, the renewable potential must first be established. After the renewable resources have been quantified, different renewable fuel production pathways can be explored, yielding total fuel production. Renewable resources considered in this work are wind, solar, and municipal waste streams.

Historically, wind speeds in the Huntington Beach area have not been high enough to support wind power generation [28,29]. As a result, installing wind power generation in this community is assumed to be infeasible. Available solar radiation was defined using Typical Meteorological Year (TMY) 3 data [30].

Quantified waste stream information was provided by the operators of the Oak View Waste Transfer Station (OVWTS). The following sections describe the transformation of these renewable energy streams into renewable fuel quantities.

3.1. Excess solar energy

In order to determine the excess solar energy (solar power overgeneration) available for fuel production, both the community load and solar PV systems must be known. Concurrent work using the

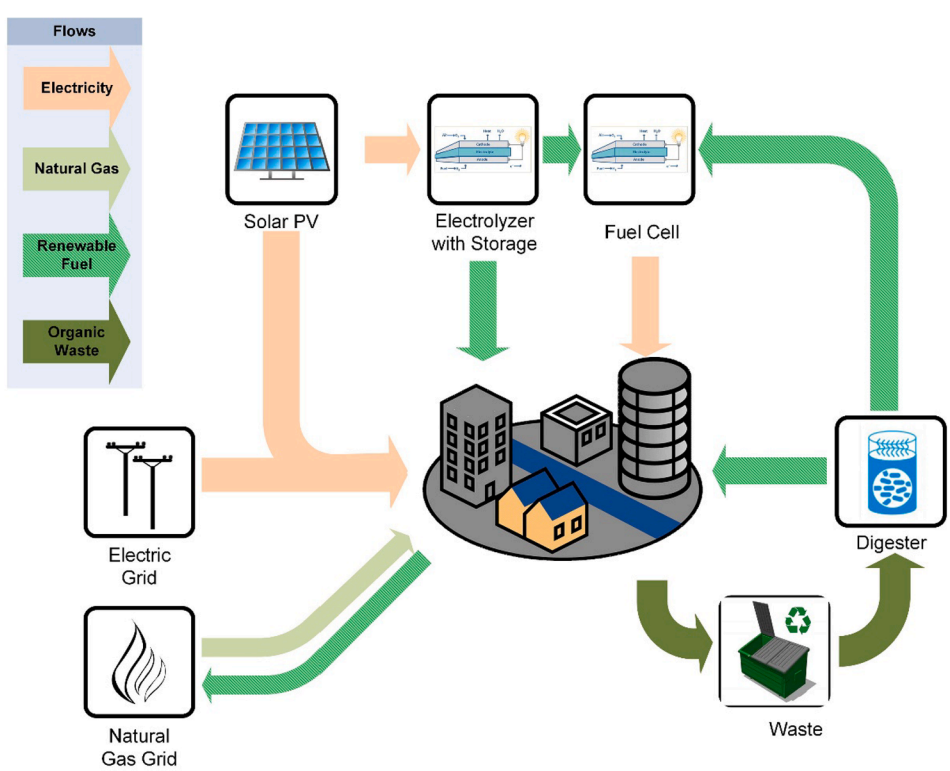

Fig. 1. System concept to maximize community renewable fuel production.

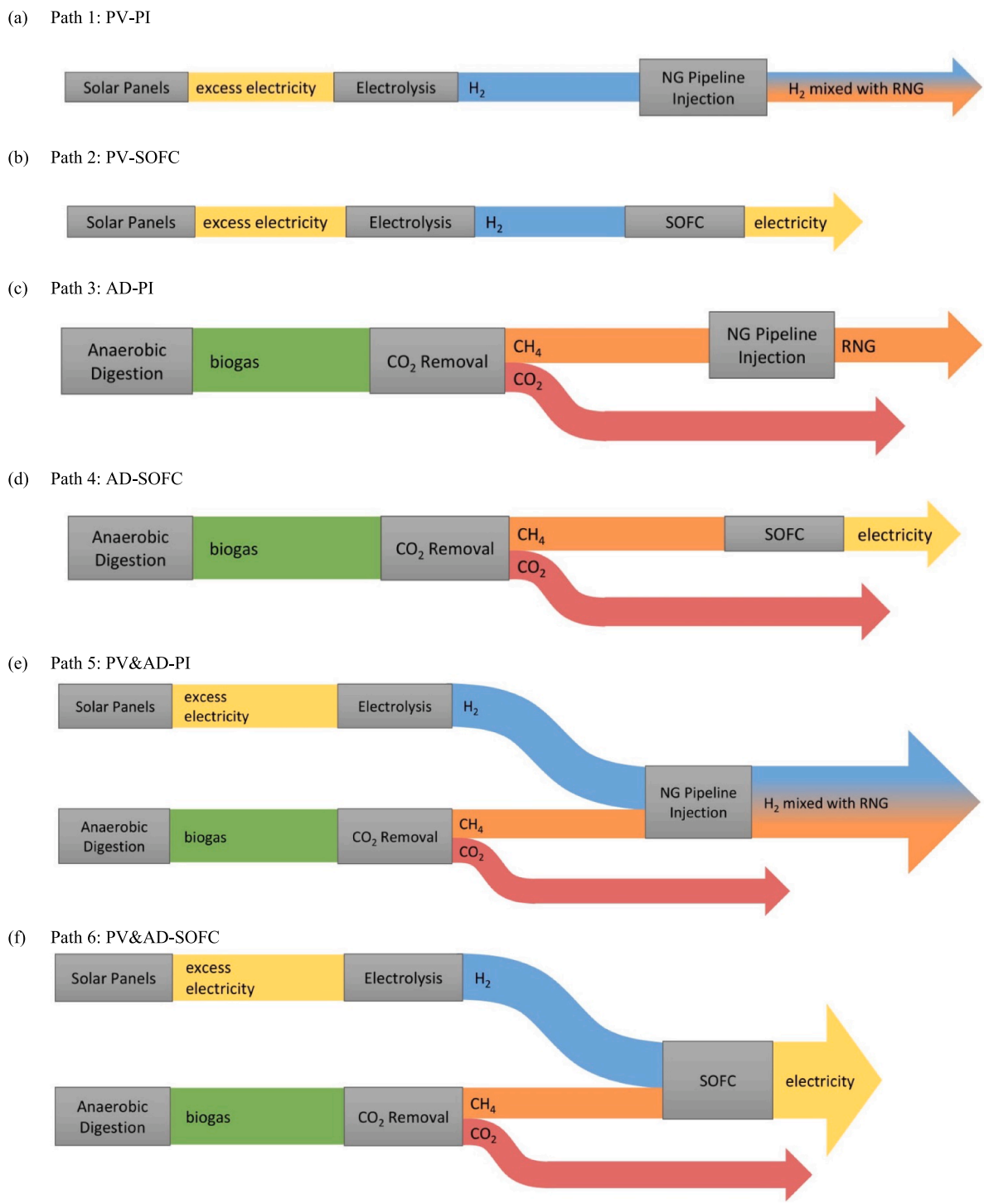

Fig. 2. Flowcharts showing the energy and material flow through the production, conversion, storage, and end use for all six pathways. Width of lines are not drawn to scale and do not include inefficiencies and energy losses.

URBANopt [31] community energy simulation tool based on the OpenStudio [32] and EnergyPlus [33] building energy simulation tools was used to generate a community scale energy use profile for the Oak View community. The models predicted that the community uses over 25.8 GWh per year, yielding an average electrical demand of 2.95 MW and a peak demand of 4.81 MW.

Solar PV capacity was predicted by using the solar PV design tool Helioscope to determine the maximum solar potential for all 310 buildings within the community [34]. Based on this work, it is projected that up to 14.6 MW of solar PV generation can be installed across the Oak View community. After conversations with solar project developers, a second scenario in which only relatively large-scale installations are pursued (>100 kW) was considered, reducing the community solar PV capacity to 6.5 MW. This second scenario is considered the "Utility" scenario due to the selection criteria for any solar PV system yielding system sizes that are more favorable to utility ownership within the community.

Net solar electricity generation was calculated by summing the positive differences of total community solar electricity production and total community electricity demand for each hour over the year. The

Table 1
Technologies included for all six production, conversion, storage and end use paths considered.

Path #	Path Name	Included Technologies					Path Description
		Solar PV (PV)	Anaerobic Digestion (AD)	Electrolysis (EC)	SOFC	NG Pipeline Injection (PI)	
1	PV-PI	✓	X	✓	X	✓	Natural gas pipeline injection of H_2 fuel from excess solar electricity.
2	PV-SOFC	✓	X	✓	✓	X	Electricity production via SOFC using H_2 fuel from excess solar electricity.
3	AD-PI	X	✓	X	X	✓	Natural gas pipeline injection of CH_4 fuel from anaerobic digestion.
4	AD-SOFC	X	✓	X	✓	X	Electricity production via SOFC using CH_4 fuel from anaerobic digestion.
5	PV&AD-PI	✓	✓	✓	X	✓	Natural gas pipeline injection of H_2 fuel from excess solar electricity and CH_4 fuel from anaerobic digestion.
6	PV&AD-SOFC	✓	✓	✓	✓	X	Electricity production via SOFC using H_2 fuel from excess solar electricity and CH_4 fuel from anaerobic digestion.

unmet load was calculated similarly as the absolute value of the sum of all negative differences of total community solar electricity production and total community electricity demand for each hour over the year. It was assumed that electricity generated within Oak View could be consumed at any load location in Oak View without incurring grid distribution losses.

3.2. Community biogas potential from anaerobic digestion

A waste collection and distribution facility located in Oak View was the only source of large-scale biomass resources within Oak View. This facility collects municipal solid waste and plans to separate and divert the organic fraction of municipal solid waste (OFMSW) to a nearby anaerobic digester as required by California law in the next few years [35]. Anaerobic digestion of municipal wastewater was not considered as there is no processing facility in the community.

During a meeting with OVWTS officials in May 2017, it was stated that the Oak View transfer station processed approximately 200,000 tons of waste annually in 2016 [35]. About 39% of total waste processed was organic, and 25% of the total waste processed was food waste [35]. Table 2 shows the assumed composition of waste processed at the facility annually.

Publicly available data on municipal waste generated in Huntington Beach were compiled and used to calculate the percentage of waste processed by the OVWTS that can be attributed to the residents of Oak View [36,37]. The average biogas yield of food and yard waste for full-scale wet OFMSW digesters cited in a 2008 report by the California Integrated Waste Management Board was 3.59 ft^3 per ton (0.112 m^3 per kg) of feedstock [38]. Because this assumed biogas yield averages reported yields of several different types of digester systems with a wide variety of feedstock compositions, the current study does not specify any particular detailed feedstock composition. The amount of biogas produced from OFMSW generated by Oak View residents was calculated assuming a biogas density of 1.15 kg/m^3 and composition of 60% CH_4 and 40% CO_2. Biogas upgrading facilities were assumed to have an efficiency of 90% [39].

Table 2
Quantity of waste processed annually in 2016 at the Oak View waste transfer station categorized by type.

Waste Material	MSW Processed by Republic Facility (tpy)	Percentage of Total
Non-Organic MSW	122,000	61%
Organic MSW	78,000	39%
Food Waste	50,000	25%
Yard Waste & Other Organics	28,000	14%
Total	200,000	100%

3.3. Financial assumptions

Levelized cost of energy values are calculated for multiple different fuel and technology pathways in Section 5.3. System lifetime is based upon expected operational life of each of the technologies, such as 30 years for anerobic digesters. Other technologies that typically have shorter lifetimes than 30 years are accounted for by including the appropriate periodic replacement costs through operations and maintenance cost figures. Financial assumptions are based upon published figures, personal correspondence with energy economists, and University of California, Irvine facilities personnel. The following financial assumptions were made for these calculations:

- System lifetime: 30 years
- All projects are financed using 20% equity, 80% debt
- Cost of debt is 8%
- Cost of equity is 12%
- Overall discount rate is 8%

4. Technology and cost characterization

The current work examined renewable fuel production and conversion pathways, requiring several technologies and analysis methods to be implemented. This section reviews the technical and economic characteristics of the different technologies included in this evaluation.

The cost of energy calculated using the current and future costs presented in this work is compared to a cost of $2 per MMBtu for fuel, and a cost of $0.18 per kWh for electricity. If these costs are approached or achieved, then the proposed methods will have likely achieved or surpassed parity with conventional energy procurement and conversion methods available today.

4.1. Equipment performance and cost

4.1.1. Solar PV

Residential solar PV has a capital cost of $2,530/kW, and commercial solar PV has a capital cost of $1,395/kW in 2017 [40]. Both have operational lifetimes of 30 years and annual operation and maintenance (O&M) costs of $21/kW/year [41]. For all Maximum scenario paths, PV installations are split approximately 47% and 53% between residential and commercial systems, respectively. For all Utility scenario paths, PV installations are assumed to be all commercial rooftop systems. Capital as well as operating and maintenance (O&M) costs – accounting for replacement costs where applicable – are summarized in Table 4 for all referenced technologies.

4.1.2. Anaerobic digestion and biogas upgrading

Anaerobic digestion (AD) is a series of biological processes in which microorganisms break down biodegradable material in the absence of oxygen to produce biogas, a methane-rich gaseous fuel. AD is the only

commercial technology used to convert biomass to a readily available fuel that is nearly carbon neutral [42]. AD uses organic wastes, including livestock manure; municipal wastewater solids; food waste; the organic fraction of municipal solid waste; and fats, oils, and grease that would otherwise be landfilled, incinerated, or used directly as agricultural fertilizer, as feedstock for the digestion reaction [43].

Biogas yields of AD are strongly dependent upon feedstock composition, which is highly variable with location, population density, season, sector of the source material, and use of pre-treatment options [44]. Relevant literature recommends that the OFMSW be mixed with chipped wood to produce a feedstock with about 44% total solids to be digested over 30 days, after a 3–4 day aerobic pre-treatment that slowly raises the feedstock from ambient temperature to 37 °C [45,46]. Each digestion batch should consist of half new feedstock material and half digestate from the previous batch [46]. Biogas is typically comprised of 50–70 vol % methane, 30–50 vol% carbon dioxide, and a few percent by volume of trace volatile compounds Biogas is often upgraded to renewable natural gas (RNG) through a multi-step process that includes carbon dioxide removal, gas drying, minor contaminant removal, and often compression in upgrading systems with energy efficiencies of 85–98% [47].

Upgraded biogas is used locally by the producer, compressed and sold as compressed natural gas (CNG) vehicle fuel, or injected into the natural gas pipeline distribution network. CNG production is less expensive than biogas upgrading for pipeline injection, however, local CNG demand must be strong to economically justify production. Both AD and biogas upgrading demonstrate strong economies of scale with throughput capacity [39,48,49]. The economic feasibility of anaerobic digestion as waste treatment depends on a large number of location-specific variables such as local energy and waste markets, population density, and climate [50]. Estimates in existing literature are highly varied and often site-specific [50–52]. Parker, et al. defined functions approximating anaerobic digestion system capital and O&M costs specific to California markets that are referenced in Table 4. The cost of feedstock materials for anaerobic digestion are assumed to be zero, and the assumed lifetime of an AD facility is 30 years.

4.1.3. Power-to-Gas (PtG)

The foundation of all PtG systems is electrolysis, which uses an electric current to electrochemically convert water into oxygen and hydrogen (Eq. (1)).

Table 3 compares characteristics of the three major electrolysis technologies: alkaline electrolysis cell (AEC), proton exchange membrane electrolysis cell (PEMEC), and high-temperature solid oxide electrolysis cell (SOEC) technology. Alkaline electrolysis is the most mature electrolysis technology and has been commercially available for decades and is typically well-suited to PtG applications where the power supply is often intermittent and fluctuating [17]. AEC systems at ambient temperatures start in 30–60 min and can be operated between 20% and 150% of their design capacity [17]. The cost of an AEC is estimated at $1200/kW$_e$ for a 1 MW$_e$ system [16,17,53].

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2 \tag{1}$$

PEMEC is also a fairly mature technology with the first commercial system produced in 1978 [17]; however, its capital cost is about twice that of AEC systems with roughly the same efficiency [17]. SOEC operates at high temperatures between 650 and 1000 °C enabling very high efficiencies up to 90% [60,61]. SOEC systems are a fairly new technology and not yet commercially available [16,54]. Many academic and industry experts expect SOEC to become a popular PtG technology for most high capacity factor applications by 2030 as price decreases [16].

All electrolysis systems have low maintenance costs compared to capital and electricity input costs. Alkaline electrolysis O&M costs are approximately 1.5% of total capital expenditure (including initial capital cost and stack replacement costs) [63,64]. Stack replacement occurs every 10 years over the system's 30-year operational lifetime [17,63]. Each stack replacement cost is assumed to be $840/kW$_e$ and is paid in monthly installments throughout the previous stack's lifetime with an 8% annual credit on payments. Modeled electrolysis systems have a 0.8 capacity factor. The O&M cost shown in Table 4 includes maintenance fees as well as stack replacement costs. Based on these cost values, all subsequent electrolyzer calculations assume the adoption of alkaline electrolyzer technologies.

4.1.4. Solid oxide fuel cell technology

As SOFCs have been recently commercialized, reports on SOFC capital costs vary widely. However, most reports estimated the cost of an SOFC system to be $5,000–6500 per kW$_e$ [62,66]. An SOFC capital cost of $5000 per kW$_e$ is used in subsequent calculations. The SOFC O&M cost equation presented in Table 4 assumes a capacity factor of 0.8, a stack replacement cost of $1500/kW, and a stack lifetime of 5 years. This work assumes that an SOFC operates with an electrical efficiency of 60%. Commercially available SOFC models are typically designed to operate using natural gas, but primarily use hydrogen to drive the electrochemical process [67]. This work assumes that the SOFC can be operated using either methane, hydrogen, or a mixture of both.

4.1.5. Natural gas pipeline injection

Injection of RNG into the natural gas distribution grid allows the use of natural gas pipelines for transport and storage of renewable fuels. If a renewable fuel is to be injected into the natural gas distribution grid it must be processed to comply with quality requirements established by the local gas utility. California has the most stringent gas quality standards (see Rule No. 30 by the Southern California Gas Company (SCG)) when compared to other states and European countries [68–70]. Strict

Table 3
Comparison of AEC, PEMEC, and SOEC characteristics.

	AEC		PEMEC		SOEC	
Electrolyte	Aq. Potassium hydroxide		Polymer membrane		Yittria stabilized Zirconia	
Operating Temp. (°C)	40–90	[54]	20–100	[54]	650–1000	[55,56]
Gas Purity (%)	>99.5	[57]	99.99	[58]	99.9	[16]
Lower Dynamic Range	10–40%	[58]	0–10%	[17,54]	>30%	[16]
System Response	Seconds	[59]	Milliseconds	[59]	Seconds	[16]
Cold-start time (min)	<60	[53]	<20	[53]	<60	[16]
Stack Lifetime (h)	60,000–90,000	[53]	20,000–60,000	[53]	10,000	[a]
Maturity	Mature	[16,17]	Commercial	[54]	Demonstration	[16,54]
Efficiency	62–82%	[54]	67–82%	[54]	60–90%	[60,61]
2018 Capital Cost ($/kW$_e$)	1,080–1,300	[16,53]	2,170–2,510	[16,53]	6,500	[b]
2030 Capital Cost[c] ($/kW$_e$)	813	[16]	921–1790	[16]	1140–4,600	[16,17]

[a] Industry experts interviewed estimated SOEC lifetimes to be significantly longer than 10,000 h [16]. However, there is little evidence in the literature proving longer lifetimes.
[b] Indirect from SOFC costs reported in [62].
[c] Projected capital costs from interviewed industry and academic experts [16].

Table 4
Summary of current capital and O&M costs for all relevant technologies.

System Component	Capital Cost		Annual O&M Cost	
Residential Solar PV	$\$2,530*P_{kWe}$	[40]	$\$21*P_{kWe}$	[41]
Commercial Solar PV	$\$1,395*P_{kWe}$	[40]	$\$21*P_{kWe}$	[41]
MSW Anaerobic Digestion	$\$2,508,900(MSW_{CAP})^{0.5}$	[39]	$\$162,775(MSW_{CAP})^{0.6}$	[39]
Biogas Upgrading for Pipeline	$\$1,370,000(flow_{RNG})^{0.56}$	[39]	$\$101,625(flow_{RNG})^{0.81}$	[39]
Alkaline Electrolysis	$\$1,200*P_{kWe}$	[16,17,53]	$\$57.4*P_{kWe}$	[63,64]
Catalytic Fixed-bed Methanation	$\$0.007(CAP_{kW})^{0.6823}$	[b]	$0.0835*Capital_{MT}$	[65]
SOFC	$\$5,000*P_{kWe}$	[62,66]	$\$959*P_{kWe}$	[62]
Renewable Natural Gas Injection	$\$615,750(flow_{RNG})^{0.42}$	[39]	$\$28,425(flow_{RNG})^{0.35}$	[39]

P_{kWe} is electric power in kW.
MSW_{CAP} is the digester capacity in thousands of tons of MSW input per year.
$flow_{RNG}$ is the output flowrate of renewable natural gas in MMBtu/h.
P_{kWe} is the electrical power capacity of the electrolyzer in kW.
$MT_{Capital}$ is the capital cost of the methanation system.
$P_{Capital}$ is the capital cost of the RNG pipeline.
[a]Includes only replacement cost as batteries require little-to-no O&M expenses.
[b] Equation was obtained from best-fit line of values found in the literature.

standards correlate with increased biogas upgrading costs [69]. Northern California's major utility provider, Pacific Gas and Electric Company, estimates the cost of interconnection to the natural gas pipeline for a gas producer to be $1,500,00–3,000,000 in California (compared to $75,000–500,000 in other states) [71,72]. SCG, the natural gas utility company serving Oak View, requires three engineering studies costing over $200 K over one year before an injection project is approved [73]. The California Public Utilities Commission estimates a cost of $1.2–1.9 million to build a point of receipt facility with a monthly operating cost of $3500 [71]. Parker, et al. presents functions (found in Table 4) describing capital and O&M costs for pipeline injection of RNG in California that are corroborated by the costs cited by utility companies [39]. These pipeline injection cost equations assume a 30-year economic lifetime.

Injection of hydrogen into the natural gas grid is currently done in several countries, mainly in Europe [17]. Scientific literature has reported that 5–20% hydrogen would be tolerable for most residential and commercial end-use appliances [74]. In 2015 researchers at University of California, Irvine in partnership with SCG installed the first hydrogen pipeline injection project in the U.S. [75,76]. Electrolysis using solar electricity produces the renewable hydrogen that is injected into a natural gas pipeline directly upstream of the campus's power plant [75]. Hydrogen pipeline injection is assumed to have the same costs as RNG pipeline injection in the current analyses.

4.1.6. Equipment cost summary

Dynamic operation should be considered for the efficiency and cost analysis of any real system. Alternatively, natural gas and grid electricity could be used to supplement sustainable fuel and electricity as needed to operate technologies at steady-state. This study does not account for possible increased operation and maintenance costs of dynamic equipment operation.

For technologies with an expected lifetime less than 30 years, the expected lifetime of a power or fuel generation plant, replacement costs are included in the O&M costs shown in Table 4. Replacement costs were calculated as monthly payments over the lifetime of the previous component or component cell stack with an 8% annual credit on payments.

4.1.7. Future cost projections

The values presented in the previous section represent current unsubsidized costs for technologies and systems that are either not widely deployed today (e.g., SOFC), or have only been pursued at limited scale (e.g., natural gas pipeline injection) to-date. Based on these costs, it can be easily hypothesized that the energy pathways presented in this work are much more expensive than current widely used fuel supply and conversion pathways. Considering that fact that current jurisdiction in many locations (including California) do not yet allow the proposed pathways described in Section 2, this work should consider future implementation. Future implementation will also likely come with significant cost reductions. As a result, the current analyses will also consider future costs.

For the current work, future cost projections were developed for the various technologies considered from the following sources:

- Solar PV cost projections are based upon the assumption that cost goals set by the U.S. Department of Energy Solar Energy Technologies Office are met [77]. Under these assumptions, future solar costs decrease to $750 and $620 per kW for residential and commercial systems, respectively.
- SOFC cost projections are based on the projection that SOFC production increases significantly [78]. Under this assumption, SOFC capital cost decreases to $1600 per kW and annual O&M costs decrease to $306 per kW per year.
- Low temperature electrolysis costs decrease due to increased demand and production [53], leading to a reduce AEC capital cost of $360 per kW. Note that this value is taken from the lower bound of projected costs.
- Anaerobic digestion capital costs have been projected to drop by 50% [79]. This work conservatively assumes that this same cost reduction occurs for biogas upgrading equipment (a much less mature and emerging related technology) in the future.
- This work conservatively assumes that the cost of pipeline injection (also a less mature and emerging related technology) decreases by 50%.

These cost and performance assumptions are based on future projections. The reality of technology development is likely to differ depending upon technical and economic conditions. This reality creates the largest source of error for projecting future costs in the current analyses. Assuming that these projections accurately represent a likely scenario, the current methods and assumptions are expected to be valid and reliable for projecting future renewable fuel and energy costs.

4.2. Waste transfer

Another consideration when siting an anaerobic digester is potential resistance from local residents and stakeholders. Public interviews of

Oak View residents and stakeholders revealed that the siting of an anaerobic digester at the local waste transfer station is undesirable. As a result, RNG production from community waste in this case and many (perhaps most) similar cases requires waste transfer to an existing AD system. Further interviews with the waste transfer station operators indicated that transfer of organic waste to an AD system located in Perris, CA is planned. Analysis of the process of transferring organic waste from the Oak View community to the Perris, CA digester system is included in this work.

To pursue this project, the economic, energy, and environmental impact of transporting additional feedstock to support AD operation would be necessary. As previously stated, relevant literature recommends that OFMSW be mixed with chipped wood to produce maximum biogas generation [45,46]. The sustainability and economic viability of sourcing and transporting lignocellulosic feedstocks (chipped wood) for any given project depend on the proximity of the project to and the method used to the generate feedstock material:

- Woody biomass can be obtained either by harvesting woody biomass from forests, capturing logging residues, or the farming of lignocellulosic crops [80,81].
- Zhu, et al. discusses energy consumption of woody biomass pretreatment for anaerobic digestion [82].
- An, et al. and Neimela, et al. provide detailed models to assess the economic viability of lignocellulosic feedstock-based biofuel projects [83,84].

A primary outcome of this prior work is to indicate that sourcing of this necessary woody biomass is necessary to fully evaluate the environmental, energetic, and economic sustainability of any new AD project.

Using the 2017 Alternative Fuel Life-Cycle Environmental and Economic Transportation (AFLEET) Tool, a module of the GREET 2016 software, produced by U.S. Department of Energy's Argonne National Laboratory, the expected emissions for trucking OFMSW processed at the Oak View waste transfer station to the AD located in Perris, CA, were calculated [81]. Fig. 3 shows the Google Maps suggested driving routes between these locations. The shortest driving distance between the facilities is 66.6 miles (133.2 miles roundtrip) [82].

Four types of heavy-duty vehicles are considered for the transport of all 78,000 tons of organic MSW processed by the OVWTS in 2017 as follows: (1) class 7 single unit short-haul (SUSH), (2) class 7 single unit long haul (SULH), (3) class 8 combination short-haul (CSH), and (4) class 8 combination long-haul (CLH). These categories are defined using gross vehicle weight rating (GVWR). Class 7 vehicle GVWR range from 26,001 to 33,000 lbs. and have a maximum payload capacity of 18,500 lbs. [83]. Class 8 vehicle GVWR range from 33,001 to 80,000 lbs. and have a maximum payload capacity of 54,000 lbs. [83]. All trucks are assumed to be 2017 diesel-powered models. Assumed values for payload capacity, annual miles traveled per vehicle, miles per gallon diesel (MPG_{diesel}), and annual criteria pollutant emissions used in the AFLEET analysis of the four truck types are compared in Table 5 [81].

4.3. Revenue streams

The current work considers two forms of revenue to offset capital and operating costs: (1) Low Carbon Fuel Standard (LCFS) credits, and (2) tipping fees. LCFS credits can be generated when the produced renewable fuel is used as a transportation fuel, offsetting the use of nonrenewable fuels [84]. Assuming an LCFS credit value of $150 [85–87], that the fuel will be used to offset gasoline (or that the energy economy ratio is one), and that the carbon intensity of the renewable fuels considered in this work is zero [88], an LCFS credit value of $14.56 per MMBtu is available in 2020, and $12.59 per MMBtu in 2030, with the credit price decreasing by approximately $0.20 per MMBtu per year. Note that LCFS is currently set to expire in 2030. This work will assume two LCFS scenarios. The first is that LCFS credits are not available after

Table 5
Properties of and annual criteria pollutant emissions from the annual operation of one vehicle in each truck category [81,83].

Truck Class	7		8	
Truck Description, 2017 Model	Single Unit Short-Haul	Single Unit Long-Haul	Combination Short-Haul	Combination Long-Haul
Maximum Payload (lbs.)	18,500	18,500	54,000	54,000
Annual Miles Per Vehicle	16,500	23,000	65,000	170,000
MPG_{diesel}	7.4	6.6	7.4	7.3
MPGGE	6.4	5.7	6.4	6.3
Annual Fuel Consumption (GGE/year)	2573	4044	10,138	26,877
Annual CO_2 Emissions Per Vehicle (US Tons)	31.7	49.8	124.8	330.9

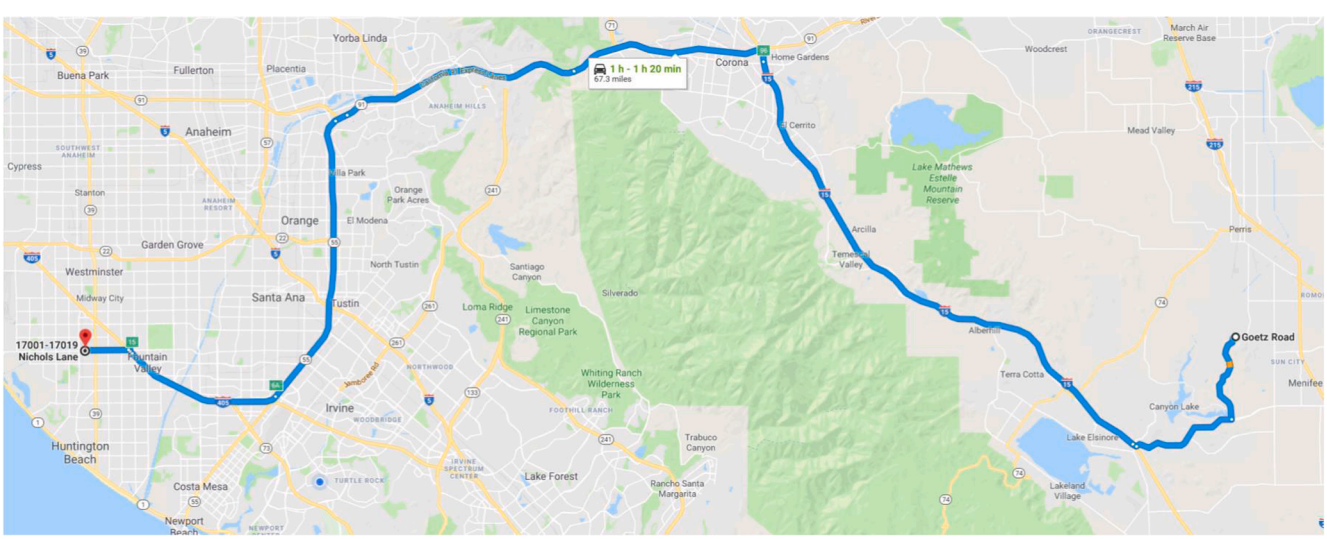

Fig. 3. Google Maps suggested driving routes between Oak View (17,001–17,019 Nichols Lane) to the anaerobic digester in Perris (Goetz Road) [82].

2030, the second is that LCFS credits are available through 2050 and decrease by $0.20 per MMBtu per year. When using the future costs presented in Section 4.1.7, it is assumed that LCFS credits have decreased to $8.80 per MMBtu, and that the credits will continue to decrease by $0.20 per MMBtu per year. LCFS credits only apply if the renewable gas is delivered for use in a vehicle. Scenarios in which the fuel is used to generate electricity are not eligible for LCFS credits.

Tipping fees are generated by charging for the dumping of waste and are set using a dollar per ton valuation. The current work will not assume a tipping fee, but will calculate a tipping fee required to reach a certain threshold. Tipping fees are independent of renewable fuel end use and are applied to all waste that passes through the transfer station.

Once the vehicle has arrived at the established AD, it is assumed that a tipping fee is required to dispose of the organic waste. The tipping fee is the cost per ton of feedstock deposited, or "tipped", by a transport truck at an existing anaerobic digester facility. The tipping fee is the price the anaerobic digestion facility must charge for accepting feedstock in order to recover the costs associated with the AD facility. The current work does not determine current tipping fees but looks to establish a ceiling on the maximum allowable tipping fee when considering the costs, incentives for, and value of renewable natural gas.

If the AD derived RNG is used to replace diesel fuel, then RNG sales can be supported using Low Carbon Fuel Standard (LCFS) and Renewable Identification Number (RIN) credits. The LCFS credit price is found for compressed RNG being used as a substitute for diesel fuel using the assumption that RNG has carbon intensity score of 11.26 g CO_2e/MJ [84], the LFCFS credit trading price is $154 [89], the EER value is 1 for compressed natural gas used in a heavy-duty compression ignition engine [90], and the compliance year is 2020. The resulting LCFS credit price is $13.09/MMBtu [90]. For RNG that is not used as vehicle fuel, P_{LCFS} is zero. The RIN waiver credit for cellulosic RNG (D3) is $18.39/MMBtu [91]. Considering that a high RNG price can be offset by these credits, the maximum allowable tipping fee such that the eventual RNG cost does not surpass the cost of conventional natural gas is shown in Eq. (2).

$$P_{tip} = P_{NG} - P_{fuel} + P_{LCFS} + P_{RIN} \tag{2}$$

where P_{tip} is the tipping cost in $/ton OFMSW, P_{NG} is the market price of natural gas, P_{fuel} is the price of diesel fuel used to truck OFMSW from Huntington Beach to Perris per MMBtu, P_{LCFS} is the Low Carbon Fuel Standard (LCFS) credit price for low carbon transportation fuel, and P_{RIN} is the Renewable Identification Number (RIN) credit price.

5. Results

The Maximum and Utility scenarios are characterized by 14.6 MW and 6.5 MW solar PV installations, respectively, as shown in Table 6. The PV installation in the Maximum scenario meets 52% of the Oak View electrical demand, and the PV installation in Utility scenario meets 40% of the modeled Oak View electrical demand. The Maximum scenario uses a 10 MW AEC electrolyzer, while the utility scenario requires a 3.26 MW AEC electrolyzer.

According to California's Department of Resources Recycling and Recovery, residential sources in Huntington Beach produced 22,184 tons of organic municipal waste, comprised of mostly food and yard waste, annually in 2016 [36]. Table 7 shows the residential waste produced by Huntington Beach residents in 2016 categorized by material type.

The population of Huntington Beach in 2016 was 194,322 people [37]. Oak View's 10,000 residents comprise 5.1% of Huntington Beach residents. Thus, the residential organic waste generation of Huntington Beach per capita was 0.11 tons annually, and Oak View residents are thus assumed to have generated 1100 tons of organic waste per year, 1.2% of the OFMSW processed at Republic Services in 2017. City-wide and per capita biogas and RNG production potentials are summarized in Table 8. Digestion of all OMSW processed by the OVWTS would generate 200,000 MMBtu/y of renewable natural gas.

The 78,000 tons/y includes Oak View waste. This value was used to determine renewable biogas potential for the Oak View waste transfer station. However, results specific to the Oak View community in Section 5.1 and community specific results in Section 5.4 only allow for waste associated with the community itself to be considered as contributing to community energy conversion. Results in Section 5.2 and 5.3 use the total OFMSW passing through the waste transfer station.

5.1. Path results

The renewable fuel or electricity production of all paths is shown in Table 9. Path 1 describes natural gas pipeline injection of hydrogen fuel generated via electrolysis from excess solar PV electricity. Electrolysis generates 28,500 MMBtu/y of hydrogen fuel in the Maximum scenario and 3600 MMBtu/y of hydrogen in the Utility scenario.

In path 2, hydrogen produced via electrolysis using excess solar electricity is used to operate an SOFC. Under the maximum solar PV scenario with nearly 15 MW of solar PV capacity, a 570 kW steady state SOFC can be supported. Reducing PV capacity to the utility scenario reduces SOFC capacity to 72 kW.

Path 3 describes the injection of RNG produced via anaerobic digestion into the natural gas pipeline. Both scenarios produce 2400 MMBtu/y of RNG in this path. In path 4, waste associated with the community would produce enough RNG to support a 47 kW SOFC operated at steady state.

Path 5 describes the pipeline injection of the mixture of hydrogen fuel from electrolysis and RNG from anaerobic digestion. The injected fuel in the Utility scenario is comprised of 95% RNG and 5% hydrogen, well below the concentration limit accepted by many European countries and has a total energy content of 5900 MMBtu annually. The injected fuel in the Maximum scenario is comprised of 8% RNG and 92% hydrogen on an energy basis, which comprises a hydrogen concentration well above the limit accepted by natural gas pipelines in any country,

Table 6
Total community excess solar electricity and (b) electrolyzer and battery sizes for both solar PV size scenarios.

Scenario	Solar PV Installation Capacity (MW)	Excess Solar Electricity (MWh/year)	Community Load Met by Solar PV	Unmet Community Load (MWh/year)
Maximum	14.6	11,600	52%	8300
Utility	6.5	1450	40%	10,300

Table 7
All residential waste generated by the City of Huntington Beach in 2016 separated by material category according to California's Department of Resources Recycling and Recovery [36].

Material Category	Total Residential Tons	Percent Residential Total
All Paper	9258	18.7%
All Glass	1067	2.2%
All Metal	1448	2.9%
All Electronics	569	1.1%
All Plastic	4723	9.5%
All Food	9836	19.9%
All Yard Waste	6312	12.7%
All Manure	0	0.0%
All Other Organic	6036	12.2%
All Inerts and Other	6322	12.8%
All Household Hazardous Waste	247	0.5%
All Special Waste	1,719	3.5%
Mixed Residue	2,010	4.1%
Total	49,547	100%

Table 8
Biogas and RNG production potential by source and corresponding OFMSW mass digested.

OFMSW Source	OFMSW (tpy)	Biogas (mil. ft^3/y)	RNG (MMBtu/y)
All Processed at Republic Transfer Station	78,000	340	200,000
All Huntington Beach Residents	22,000	38	51,000
All Oak View Residents	1100	0.055	2400
Per Capita in Oak View	0.11	0.0000055	0.24

Table 9
Fuel quantities injected into the natural gas pipeline in paths 1, 3, and 5, and steady state SOFC power output for paths 2, 4, and 6 for both solar PV size scenarios.

Path	Fuel Source	Fuel Type	Fuel Injected into NG Pipeline (MMBtu/y)		Steady-State SOFC Power Output (kW)	
			Utility Scenario	Max Scenario	Utility Scenario	Max Scenario
Path 1	EC	H_2	3600	28,500	–	–
Path 2	EC	H_2	–	–	72.	570
Path 3	AD	RNG	2400	2400	–	–
Path 4	AD	RNG	–	–	47	47
Path 5	AD	RNG	3600	28,500	–	–
	EC	H_2	2400	2400		–
	All	RNG & H_2	5900	30,900	–	–
Path 6	AD	RNG	–	–	47	47
	EC	H_2	–	–	72	570
	All	RNG & H_2	–	–	119	617

and has a total energy content of 28,500 MMBtu annually. Thus, if this gas was produced at this site, it would be necessary to first mix it with pipeline natural gas to bring the hydrogen concentration down to the acceptable limit (assumed to be 5% in this case). Further investigation into the natural gas pipeline capacity and flow rate dynamics at the proposed injection site are required to assess the final hydrogen concentration percentage after pipeline injection and the viability of this pathway.

Path 6 describes the steady-state electrical output of an SOFC fueled by the mixture of hydrogen from electrolysis and RNG from anaerobic digestion. Total continuous electric power production from the SOFC is 119 kW in the Utility scenario and is 570 kW in the Max scenario.

5.2. OFMSW trucking results

The total number of required vehicle roundtrips was found by rounding up the quotient of the annual weight of OFMSW by vehicle weight capacity. The number of vehicles required for transport is calculated by dividing the number of roundtrips by typical annual miles traveled per vehicle according to the AFLEET tool. Fractional numbers of vehicles are rounded up to the nearest whole. However, calculations assume only the minimum number of total miles required to transport all OFMSW and result in conservative estimates of emissions and fuel consumption.

Both class 7 vehicle types have the same maximum payload and would need to travel over 1.36 million miles over more than 10 thousand roundtrips between Oak View and Perris, CA. Based on annual miles per vehicle, the class 7 SUSH fleet would consist of at least 83 vehicles, and SULH fleet would contain 60 vehicles. Class 8 vehicles would travel over 3.5 thousand roundtrips, requiring 8 total CSH or 3 CLH vehicles. The class 8 CLH fleet consumes the least amount of diesel fuel and produces the least amount of pollutants of all of the examined vehicles. The percent fuel energy consumed as diesel fuel used for transportation compared to the fuel energy that is produced from the OFMSW via anaerobic digestion ranges from 4.2% for the class 8 CLH fleet, to 14.0% for the class 7 SULH fleet. Fuel consumption for each fleet is shown in Table 10. Accounting for the energy loss attributed to trucking OFMSW with combination long-haul trucks, the total annual contribution that RNG energy can make from anaerobic digestion is 191,600 MMBtu/y. Only 2400 MMBtu/y can be attributed to the Oak View waste input stream.

The fuel energy used to transport OFMSW from the collection and sorting site to the AD system was determined to be a small percentage (<5%) of the total biogas potential energy of the OFMSW. Thus, the authors believe that the reduction in net energy generated from the sourcing and transporting of additional feedstock, such as woody biomass to support AD operation, would be relatively small.

5.3. Net energy analysis

Net energy analysis is conducted to determine if community-wide energy self-sufficiency (annual Zero Net Energy (ZNE)) can be achieved with the energy resources in the community. The subsequent energy analysis only considers results for the scenario where the Oak View fraction of the OFMSW is trucked out of the Oak View community. This scenario was selected as most likely to occur considering the current decision to move waste to this location combined with local desires to not install an anaerobic digester in Oak View. Table 11 shows the percent net electrical demand in Oak View after accounting for the minimum 4.2% RNG energy loss as diesel fuel consumption during trucking. Only electricity-producing paths 2, 4, and 6 are considered for this analysis and are directly compared to Oak View's modeled electrical demand to calculate percent demand met by renewable electricity production.

The results shown in Table 11(a) consider only RNG produced from OFMSW attributed to Oak View residents. An SOFC operating on net RNG fuel energy meets 2.3% of community electrical demand. The power produced from hydrogen fuel made via electrolysis using excess solar electricity meets 3.3% of total electrical demand in the Utility scenario, and 26% in the Maximum (Max) scenario. The percent total community electrical demand met by the power produced from all renewable fuels (path 6) and solar PV is 46% in the Utility scenario and 80% in the Max scenario. The largest amount of energy produced exclusively from renewable fuels is 29% in the Max scenario via path 6.

The results for cases that consider renewable fuels generated from all of the OFMSW processed at the OVWTS are shown in Table 11(b). An SOFC operating on this total amount of RNG meets 190% of community electrical demand. The percent total community electrical demand met by power produced from all renewable fuels (path 6) and solar PV is 240% in the Utility scenario and 270% in the Max scenario.

5.4. Current cost analysis

The cost analysis in this section considers the full organic throughput at the Oak View waste transfer station. When only the Oak View waste contribution is considered, costs are economically infeasible. By considering all of the OFMSW throughput at the studied location, better economies of scale can be realized. The capital and annual O&M costs of each included technology in all six energy paths are listed in Table 12. For all Maximum scenario paths, 47% of PV installations are located in the residential area, while the remaining PV installations are in commercial and industrial areas. For all Utility scenario paths, all PV installations are assumed to be in commercial locations. Note that only solar PV capital cost associated with solar energy used for fuel production was included in this analysis. Solar energy used for fuel production was 56.7% and 17.4% for the Maximum and Utility solar scenarios, respectively.

Table 10
Properties of vehicle fleets required to transport OMSW for four heavy-duty vehicle types.

Truck Class		7		8	
Truck Description, 2017 Model		Single Unit Short-Haul	Single Unit Long-Haul	Combination Short-Haul	Combination Long-Haul
Total Vehicle Roundtrips Per Year		10,247	10,247	3511	3511
Total Annual Miles Travelled by Fleet		1,364,900	1,364,900	467,665	467,665
Number of Vehicles in Fleet		83	60	8	3
Fleet Annual Fuel Consumption	Fleet Fuel Consumption (GGE/year)	212,787	239,809	72,992	75,257
	Energy content of Diesel Consumed (MMBtu)	24,279	27,363	8329	8587
	RNG (via AD) Energy Consumed in Transport of OFMSW	12.4%	14.0%	4.3%	4.2%

Table 11
Percent modeled community electrical demand met by renewable electricity and fuel generation for two anaerobic digestion feedstock cases: (a) Oak View residential OFMSW and (b) all OFMSW currently processed at Republic Services in Huntington Beach.

(a) Electrical End Use Paths Using Oak View fraction of OFMSW

	Utility Scenario		Max Scenario	
	Community Electrical Demand Met by SOFC	Total Demand met by renewables (SOFC + PV)	Community Electrical Demand Met by SOFC	Total Demand met by renewables (SOFC + PV)
Path 2	3.65%	43.7%	29.19%	80.9%
Path 4	2.31%	42.4%	2.31%	54.0%
Path 6	5.96%	46.0%	31.50%	83.2%

(b) Electrical End Use Paths Using Total OFMSW processed in Oak View

	Utility Scenario		Max Scenario	
	Community Electrical Demand Met by SOFC	Total Demand met by renewables (SOFC + PV)	Community Electrical Demand Met by SOFC	Total Demand met by renewables (SOFC + PV)
Path 2	3.65%	43.7%	29.19%	80.9%
Path 4	191.84%	231.9%	191.84%	243.5%
Path 6	195.49%	235.5%	221.03%	272.7%

LCOE values are calculated for each path on a per kWh or per MMBtu basis. Values in Table 13 include the total loan cost, all O&M costs, and the cost of diesel fuel required to truck all of the OFMSW from Huntington Beach to Perris and assuming 30-year lifetimes for the energy conversion systems. LCOEs for paths 2, 4, and 6 assume a 0.5% electricity production degradation per year. LCOEs for paths 1, 3, and 5 do not include any degradation of the renewable fuel production rate over time. Table 13 shows the levelized cost of renewable fuel energy for paths 1, 3, and 5 and LCOE of electrical energy produced via SOFC from renewable fuels for paths 2, 4, and 6 when LCFS and tipping fees are not applied.

Application of tipping fees only affects Paths 3 through 6, and LCFS only affects Paths 1, 3, and 5. Under the Max Scenario and for the electricity producing pathways (Paths 4 and 6), tipping fees must be $32.50/ton and $48.00/ton, respectively, to reduce cost of electricity to $0.18 per kWh. Under the Utility Scenario, the Path 4 tipping fee is also $32.50/ton, but the Path 6 tipping fee decreases to $35.90/ton to reach $0.18 per kWh from the fuel cell.

Fuel production LCOE depends upon both the LCFS scenario and tipping fees. Table 14 shows the effect of LCFS on renewable fuel LCOE in sub-table A, and the tipping fee required to reach $2 per MMBtu fuel. Note that, under current costs, the Utility scenario produces lower LCOE and tipping costs. The lower costs are due to a smaller electrolyzer, which produces renewable fuel at a higher cost than the much larger AD system. For the three fuel injection scenarios, fuel costs exceed the target of $2 per MMBtu, so sub-table B shows the tipping fees necessary to achieve the cost target.

Table 12
Capital and O&M cost of each technology included in Maximum and Utility scenario paths.

	Tech.	Utility Scenario		Max Scenario	
		Capital Cost ($)	O&M Cost ($/y)	Capital Cost ($)	O&M Cost ($/y)
Path 1	PV	1,577,745	23,751	15,964,095	98,568
	AEC	3,912,000	0	11,976,000	572,866
	H_2 PI	423,838	20,822	1,011,281	42,979
	Total	5,913,583	44,573	28,950,714	714,390
Path 2	PV	1,577,745	23,751	15,964,095	98,568
	AEC	3,912,000	187,128	11,976,000	572,866
	SOFC	394,444	75,657	3,166,667	607,385
	Total	5,884,189	286,536	31,106,761	1,354,093
Path 3	AD	22,158,005	2,222,514	22,158,044	2,222,514
	BG U	13,474,573	1,155,950	14,255,687	1,254,116
	RNG PI	2,172,342	81,277	2,266,120	84,191
	Total	37,804,920	3,459,742	38,679,813	3,560,821
Path 4	AD	22,158,005	2,222,514	22,158,044	2,222,514
	BG U	13,474,573	1,155,950	14,255,687	1,254,116
	SOFC	21,835,000	4,188,080	21,835,000	4,188,080
	Total	57,467,578	7,566,544	58,248,692	7,664,710
Path 5	PV	1,577,745	23,751	15,964,095	98,568
	AEC	3,912,000	187,128	11,976,000	572,866
	AD	22,158,005	2,222,514	22,158,044	2,222,514
	BG U	13,474,573	1,155,950	14,255,687	1,254,116
	RNG PI	2,190,868	81,855	2,399,804	88,310
	Total	43,313,191	3,671,198	66,753,591	4,311,648
Path 6	PV	1,577,745	23,751	15,964,095	98,568
	AEC	3,912,000	187,128	11,976,000	572,866
	AD	22,158,005	2,222,514	22,158,044	2,222,514
	BG U	13,474,573	1,155,950	14,255,687	1,254,116
	SOFC	22,229,444	4,263,737	25,001,667	4,795,464
	Total	63,351,767	7,853,080	89,355,453	9,018,802

BG U is biogas upgrading.

5.5. Future cost analysis

Future costs for the technologies considered in the current analyses were calculated using the projected costs presented in Section 4.1.7. Assuming that the renewable fuel and electricity production remain constant, the resulting LCOE values when no LCFS or tipping fees are accounted for are shown in Table 15. Note that the cost of electricity through Paths 4 and 6 are below the target of $0.18 per kWh without supplemental tipping fees. In both cases, a tipping fee of $20 per ton would reduce cost of electricity to $0.036 and $0.067 per kWh, respectively. Table 16 shows the effect of LCFS on renewable fuel costs

Table 13
Levelized cost of renewable fuel energy for paths 1, 3, and 5 and electrical energy produced via SOFC from renewable fuels for paths 2, 4, and 6. Anaerobic digestion facilities are sized to use all OFMSW processed at the OVWTS as feedstock, and *no LCFS credits or tipping fees are included.*

	Utility Scenario		Max Scenario	
	Fuel Energy Cost ($/MMBtu)	Electrical Energy Cost ($/kWh$_e$)	Fuel Energy Cost ($/MMBtu)	Electrical Energy Cost ($/kWh$_e$)
Path 1: PV-PI	$202.92	–	$39.76	–
Path 2: PV-SOFC	–	$1.28	–	$0.29
Path 3: AD-PI	$35.01	–	$17.72	–
Path 4: AD-SOFC	–	$0.37	–	$0.37
Path 5: PV&AD-PI	$37.79	–	$20.53	–
Path 6: PV&AD-SOFC	–	$0.39	–	$0.43

Table 14
Tables showing A: LCFS effects on fuel and electrical LCOE, and B: tipping fees required to achieve a fuel LCOE of $2 per MMBtu.

(a) LCOE after LCFS credits and no tipping revenue ($MMBtu)

LCFS Scenario	Utility Scenario			Max Scenario		
	Path 1	Path 3	Path 5	Path 1	Path 3	Path 5
LCFS Ending in 2030	194.64	26.73	29.50	102.47	26.73	30.49
LCFS ending in 2050	190.29	22.38	25.15	98.12	22.38	30.49

(b) Tipping fee to reach $2 per MMBtu LCOE ($/ton)

LCFS Scenario	Utility Scenario			Max Scenario		
	Path 1	Path 3	Path 5	Path 1	Path 3	Path 5
No LCFS	n/a	32.2	35.5	n/a	32.2	47.5
LCFS Ending in 2030	n/a	24	27.3	n/a	24	38.2
LCFS ending in 2050	n/a	20	23	n/a	20	33.4

Table 15
Future levelized cost of renewable fuel energy for paths 1, 3, and 5 and electrical energy produced via SOFC from renewable fuels for paths 2, 4, and 6. Anaerobic digestion facilities are sized to use all OFMSW processed at the OVWTS as feedstock, and no LCFS credits or tipping fees are included.

	Utility Scenario		Max Scenario	
	Fuel Energy Cost ($/MMBtu)	Electrical Energy Cost ($/kWh$_e$)	Fuel Energy Cost ($/MMBtu)	Electrical Energy Cost ($/kWh$_e$)
Path 1: PV-PI	$76.80	–	$39.76	–
Path 2: PV-SOFC	–	$0.45	–	$0.29
Path 3: AD-PI	$17.72	–	$17.72	–
Path 4: AD-SOFC	–	$0.15	–	$0.154
Path 5: PV&AD-PI	$18.60	–	$20.53	–
Path 6: PV&AD-SOFC	–	$0.16	–	$0.17

Table 16
Tables showing A: LCFS effects on fuel and electrical LCOE, and B: tipping fees required to achieve a fuel LCOE of $2 per MMBtu when using future costs.

(a) LCOE with no tipping revenue ($MMBtu)

LCFS Scenario	Utility Scenario			Max Scenario		
	Path 1	Path 3	Path 5	Path 1	Path 3	Path 5
LCFS ending in 2050	69.95	10.87	11.75	32.91	10.87	13.68

(b) Tipping fee to reach $2 per MMBtu LCOE ($/ton)

LCFS Scenario	Utility Scenario			Max Scenario		
	Path 1	Path 3	Path 5	Path 1	Path 3	Path 5
No LCFS	n/a	15.3	16.5	n/a	15.3	20.7
LCFS ending in 2050	n/a	8.64	9.68	n/a	8.64	13

(sub-table A), and the required tipping fee to achieve a $2 per MMBtu fuel cost (sub-table B).

6. Summary and conclusions

A model for assessing the efficiency and economic viability of community-scale renewable gas generation, conversion, and use to compliment residential PV was developed and used to evaluate renewable fuel and electricity production potential in a 10,000 resident example community in Huntington Beach, California. The model shows that the use of environmentally friendly technologies for community-scale distributed fuel generation and power systems is not economically competitive with current natural gas and utility electricity prices. However, technological advances and cost reductions expected in the next decade or two may make electrolysis and SOFC technologies significantly more cost competitive in these community energy systems. Additionally, government incentives like those available in the LCFS program of California may be sufficient to make anaerobic digestion competitive, especially at larger scales, in the present day.

The analyses show that in-community energy resources (PV and waste) are insufficient to achieve zero-net-energy for the studied community. The largest percentage of total community electrical demand is met by the Maximum scenario path 6, which includes PV electricity production, RNG production from anaerobic digestion, and hydrogen fuel production from electrolysis, which meets over 80% of the modeled total community electrical demand. In this case 52% of the community's total electrical demand is met by solar PV, 26% by an SOFC system using renewable hydrogen produced from excess solar, and 3% from SOFC production using RNG from anaerobic digestion. When solar capacity is maximized, yearly hydrogen production for the entire community is 28,500 MMBtu/y of hydrogen fuel via electrolysis and 25MMBtu/y of RNG via anaerobic digestion of residential OFMSW. When accounting for all of the OFMSW passing through the waste transfer station (which includes that from adjacent communities), RNG production increases to nearly 200,000 MMBtu per year.

The levelized cost of energy for renewable fuel production for analyzed pathways spans from $40 to $203 per MMBtu. Tipping fees between $30 and $50 per ton would reduce the cost of electricity to $0.18 per kWh, while the combination of LCFS credits and tipping fees ranging between $20 and $50 per ton could reduce RNG cost to $2 per MMBtu. If future costs for the distributed energy conversion technologies are used, RNG cost decreases to between $18 and $77 per MMBtu. If LCFS exists in the future, then tipping fees can drop to nearly $8 per ton in order to achieve an RNG cost of $2 per MMBtu. Using current costs, the LCOE for renewable electricity production spans from $0.37 to $1.28 per kWh. Using future costs, the LCOE for electricity drops to from $0.15 and $0.45 per kWh. For all cost and LCFS scenarios, the technology set that yielded the best financial performance primarily used an AD system with biogas upgrading.

CRediT authorship contribution statement

Rochelle E. Silverman: Conceptualization, Methodology, Formal analysis, Writing - original draft, Visualization. **Robert J. Flores:** Conceptualization, Methodology, Writing - review & editing, Project administration. **Jack Brouwer:** Conceptualization, Methodology, Writing - review & editing, Supervision, Funding acquisition.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

The authors gratefully acknowledge the financial support for this work which was provided by the California Energy Commission (Contract No. EPC-15-077), and the significant leadership and contributions of Rachel Salazar, our Contract Manager.

References

[1] C. P. U. Commission. 2020 planning and information for California ZNE Homes: Frequently asked questions; 2016. [Online]. Available: http://www.californiaznehomes.com/faq [Accessed: 01-Jul-2019].
[2] Bautista N. 08/28/18-Senate floor analysis for bill no. SB 100. Sacramento; 2018.
[3] AB-398 California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption; 2018.
[4] California Public Utilities Commission. California Solar Initiative (CSI) – Go Solar California. [Online]. Available: https://www.gosolarcalifornia.ca.gov/csi/index.php [Accessed: 01-Apr-2019].
[5] Geller H, Harrington P, Rosenfeld AH. Polices for increasing energy efficiency: Thirty years of experience in OECD countries 2006; 34: 556–73.
[6] Darghouth R, Barbose G, Wiser R. The impact of rate design and net metering on the bill savings from distributed PV for residential customers in California. Energy Policy 2011;39:5243–53.
[7] Funkhouser E, Blackburn G, Magee C, Rai V. Business model innovations for deploying distributed generation : The emerging landscape of community solar in the U. S. ℭ. Chem Phys Lett 2015;10:90–101.
[8] Marique A-F, Reiter S. A simplified framework to assess the feasibility of zero-energy at the neighbourhood/community scale. Energy Build 2014;82:114–22.
[9] Keirstead J, Samsatli N, Shah N, Weber C. The impact of CHP (combined heat and power) planning restrictions on the efficiency of urban energy systems. Energy 2012;41(1):93–103.
[10] Mashayekh S, Stadler M, Cardoso G, Heleno M. A mixed integer linear programming approach for optimal DER portfolio, sizing, and placement in multi-energy microgrids. Appl Energy 2017;187:154–68.
[11] Omu A, Hsieh S, Orehounig K. Mixed integer linear programming for the design of solar thermal energy systems with short-term storage. Appl Energy 2016;180:313–26.
[12] Keirstead J, Jennings M, Sivakumar A. A review of urban energy system models: Approaches, challenges and opportunities. Renew Sustain Energy Rev 2012;16(6):3847–66.
[13] Parra D, Norman SA, Walker GS, Gillott M. Optimum community energy storage for renewable energy and demand load management. Appl Energy 2017;200:358–69.
[14] Obi M, Bass R. Trends and challenges of grid-connected photovoltaic systems – A review. Renew Sustain Energy Rev 2016;58:1082–94.
[15] Saeedmanesh A, Mac Kinnon MA, Brouwer J. Hydrogen is essential for sustainability. Curr Opin Electrochem 2018;12:166–81.
[16] Schmidt O, Gambhir A, Staffell I, Hawkes A, Nelson J, Few S. Future cost and performance of water electrolysis: An expert elicitation study. Int J Hydrogen Energy Dec. 2017;42(52):30470–92.
[17] Götz M, et al. Renewable Power-to-Gas: A technological and economic review. Renewable Energy 2016;85:1371–90.
[18] van der Horst D. NIMBY or not ? Exploring the relevance of location and the politics of voiced opinions in renewable energy siting controversies. Energy Policy 2007;35:2705–14.
[19] Ohnishi S, Fujii M, Ohata M, Rokuta I, Fujita T. Resources, conservation and recycling efficient energy recovery through a combination of waste-to-energy systems for a low-carbon city. Resour Conserv Recycl 2018;128:394–405.
[20] Geng Y, Tsuyoshi F, Chen X. Evaluation of innovative municipal solid waste management through urban symbiosis: a case study of Kawasaki q. J Clean Prod 2012;18(10–11):993–1000.
[21] Ghisellini P, Cialani C, Ulgiati S. A review on circular economy: the expected transition to a balanced interplay of environmental and economic systems. J Clean Prod 2016;114:11–32.
[22] United States Census Bureau. American community survey. [Online]. Available: https://www.census.gov/programs-surveys/acs/ [Accessed: 01-Jan-2018].
[23] California Energy Commission. Project. [Online]. Available: http://innovation.energy.ca.gov/SearchResultProject.aspx?p=31052&tks=636265589163308355 [Accessed: 01-Jul-2019].
[24] Giglio E, Lanzini A, Santarelli M, Leone P. Synthetic natural gas via integrated high-temperature electrolysis and methanation: Part I—Energy performance. J Energy Storage 2015;1:22–37.
[25] Giglio E, Lanzini A, Santarelli M, Leone P. Synthetic natural gas via integrated high-temperature electrolysis and methanation: Part II—Economic analysis. J Energy Storage 2015;2:64–79.
[26] Benjaminsson G, Benjaminsson J, Rudberg RB. Power-to-Gas – A technical review. Malmö 2013.
[27] Apt J, Newcomer A, Lave LB, Douglas S, Dunn LM. An engineering-economic analysis of syngas storage final report; 2008.
[28] AWS Truepower and U.S. National Renewable Energy Laboratory. California 80-Meter Wind Resource Map. WINDExchange; 2017.
[29] Wind Energy Technologies Office of the U.S. Department of Energy. Wind resource assessment and characterization. Office of Energy Efficiency & Renewable Energy Website. .
[30] Wilcox S, Marion W. Users manual for TMY3 data sets. Golden (CO); 1994.
[31] Polly B, et al. From zero energy buildings to zero energy districts. Goldcn, CO (United States): NREL (National Renew Energy Lab (NREL)); 2016.
[32] Guglielmetti R, Macumber D, Long N. OpenStudio: An open source integrated analysis platform. In: Proceedings of the 12th conference of international building performance simulation association; 2011.
[33] Crawley DB, et al. EnergyPlus: creating a new-generation building energy simulation program. Energy Build 2001;33(4):319–31.
[34] Folsom Labs. HelioScope: Advanced solar design software; 2017.
[35] Silverman R. Notes from meeting between UCI and republic services. Huntington Beach; 2017.
[36] CalRecyle. Residential waste stream by material type.
[37] CalRecycle. Solid waste characterization home page: CalRecycle, California Department of Resources Recycling and Recovery.
[38] Rapport J, Zhang R, Jenkins BM, Williams RB. Current anaerobic digestion technologies used for treatment of municipal organic solid waste (Publication #IWMB-2008-011). Sacramento; 2008.
[39] Parker N, Williams R, Dominguez-Faus R, Scheitrum D. Renewable natural gas in California: An assessment of the technical and economic potential. Energy Policy 2017;111:235–45.
[40] Lazard. Levelized cost of energy 2017; 2018. .
[41] Fu R, Feldman D, Margolis R, Woodhouse M, Ardani K. U.S. solar photovoltaic system cost benchmark: Q1 2017. Denver; 2017.
[42] Tabasová A, Kropáč J, Kermes V, Nemet A, Stehlík P. Waste-to-energy technologies: Impact on environment. Energy 2012;44(1):146–55.
[43] United States Environmental Protection Agency. AgSTAR: Biogas recovery in the agriculture sector.
[44] Alibardi L, Cossu R. Composition variability of the organic fraction of municipal solid waste and effects on hydrogen and methane production potentials. Waste Manag 2015;36:147–55.
[45] Papurello D, Lanzini A, Leone P, Santarelli M, Silvestri S. Biogas from the organic fraction of municipal solid waste: Dealing with contaminants for a solid oxide fuel cell energy generator. Waste Manag 2014;34(11):2047–56.
[46] Papurello D, Lanzini A, Tognana L, Silvestri S, Santarelli M. Waste to energy: Exploitation of biogas from organic waste in a 500 Wel solid oxide fuel cell (SOFC) stack. Energy 2015;85:145–58.
[47] Sun Q, Li H, Yan J, Liu L, Yu Z, Yu X. Selection of appropriate biogas upgrading technology-a review of biogas cleaning, upgrading and utilisation. Renew Sustain Energy Rev 2015;51:521–32.
[48] Di Matteo U, et al. Energy contribution of OFMSW (organic fraction of municipal solid waste) to energy-environmental sustainability in urban areas at small scale. Energies 2017;10(2):229.
[49] Hengeveld EJ, van Gemert WJT, Bekkering J, Broekhuis AA. When does decentralized production of biogas and centralized upgrading and injection into the natural gas grid make sense? Biomass Bioenergy 2014;67:363–71.
[50] Franchetti M, Dellinger A. Economic feasibility of a municipal food waste collection and energy generation model. Energy Technol Policy 2014;1(1):52–8.
[51] Shiratori Y, Oshima T, Sasaki K. Feasibility of direct-biogas SOFC. Int J Hydrogen Energy 2008;33(21):6316–21.
[52] Kaneko T, Brouwer J, Samuelsen GS. Power and temperature control of fluctuating biomass gas fueled solid oxide fuel cell and micro gas turbine hybrid system. J Power Sources 2006;160(1):316–25.
[53] Bertuccioli L, Chan A, Hart D, Lehner F, Madden B, Standen E. Development of water electrolysis in the European Union. Fuel Cells Hydrog Jt Undert 2014;83:2014.
[54] Carmo M, Fritz DL, Mergel J, Stolten D. A comprehensive review on PEM water electrolysis. Int J Hydrogen Energy 2013;38(12):4901–34.
[55] Laguna-Bercero MA. Recent advances in high temperature electrolysis using solid oxide fuel cells: A review. J Power Sources 2012;203:4–16.
[56] Kilner JA. Functional materials for sustainable energy applications. Woodhead Pub; 2012.
[57] Zeng K, Zhang D. Recent progress in alkaline water electrolysis for hydrogen production and applications. Prog Energy Combust Sci 2010;36(3):307–26.
[58] Lehner M, Tichler R, Steinmüller H, Koppe M. Storage options for renewable energy. Power-to-Gas: Technology and business models. Cham: Springer International Publishing; 2014.

[59] Lehner M, Tichler R, Steinmüller H, Koppe M. The power-to-gas concept. Cham: Springer; 2014. p. 7–17.
[60] Ni M, Leung MKH, Leung DYC. Technological development of hydrogen production by solid oxide electrolyzer cell (SOEC). Int J Hydrogen Energy 2008;33(9): 2337–54.
[61] Hauch A, Ebbesen SD, Jensen SH, Mogensen M. Highly efficient high temperature electrolysis. J Mater Chem 2008;18(20):2331–40.
[62] Darrow K, Tidball R, Wang J, Hampson A. Catalog of CHP technologies; 2017.
[63] Jacobs J. Economic modeling of cost effective hydrogen production from water electrolysis by utilizing Iceland's regulating power market; 2016.
[64] Zoulias EI, Lymberopoulos N. Techno-economic analysis of the integration of hydrogen energy technologies in renewable energy-based stand-alone power systems. Renew Energy 2007;32(4):680–96.
[65] Baier J, Schneider G, Heel A. A cost estimation for CO2 reduction and reuse by methanation from cement industry sources in Switzerland. Front Energy Res 2018; 6:5.
[66] Chatsko M. Bloom energy is the newest fuel cell stock, but is its technology already outdated? The Motley Fool 2018.
[67] Ohayre R, Cha S-W, Prinz FB, Colella W. Fuel cell fundamentals. John Wiley & Sons; 2016.
[68] Svensson M. Biomethane standards: Gas quality standardization of biomethane, going from national to international level. In: Presentation at European biomethane workshop, 11 March 2014, Brussels; 2014.
[69] Coker C. Pipeline injection of biomethane in California. Biocycle 2018;59(3):32.
[70] Skopec D. Rule No. 30: Transportation of customer-owned gas. Los Angeles; 2018.
[71] COM/CAP/lil. Decision 15-06-029: Decision regarding the costs of compliance with decision 14-01-034 and adoption of biomethane promotion policies and program; 2015.
[72] Pacific Gas and Electric Company. Tariff schedule applicable to gas service of Pacific gas and electric company. San Francisco; 2013.
[73] Southern California Gas Company. Renewable natural gas toolkit; 2017.
[74] Melaina MW, Antonia O, Penev M. Blending hydrogen into natural gas pipeline networks: A review of key issues. Denver; 2013.
[75] UC Irvine injects P2G green hydrogen into campus power supply. Fuel Cells Bull. 2017; 2017(1): 10.
[76] Southern California Gas Company. Power-to-Gas Technology. [Online]. Available: https://www.socalgas.com/smart-energy/renewable-gas/power-to-gas.
[77] Fu R, Feldman D, Margolis R. U.S. solar photovoltaic system cost benchmark: Q1 2018. Natl. Renew. Energy Lab.; 2018. p. 1–47.
[78] Scataglini R et al. A total cost of ownership model for solid oxide fuel cells in combined heat and power and power-only applications; 2015.
[79] Aas D et al. Natural gas distribution in California's low – carbon future; 2019.
[80] He L, English BC, Menard RJ, Lambert DM. Regional woody biomass supply and economic impacts from harvesting in the southern U.S. Energy Econ 2016;60: 151–61.
[81] Zhu JY, Zhuang XS. Conceptual net energy output for biofuel production from lignocellulosic biomass through biorefining. Prog Energy Combust Sci 2012;38(4): 583–98.
[82] Zhu JY, Pan X, Zalesny RS. Pretreatment of woody biomass for biofuel production: Energy efficiency, technologies, and recalcitrance. Appl Microbiol Biotechnol 2010;87(3):847–57.
[83] An H, Wilhelm WE, Searcy SW. A mathematical model to design a lignocellulosic biofuel supply chain system with a case study based on a region in Central Texas. Bioresour Technol 2011;102(17):7860–70.
[84] Niemela MV, Murray G, Roder H. Biomass sourcing and logistics: From theory to practice biomass sourcing and logistics: From theory to practice. Int J Chem React Eng 2010;8.
[85] Argonne National Laboratory. Alternative Fuel Life-Cycle Environmental and Economic Transportation (AFLEET) Tool 2017; 2017.
[86] California Air Resources Board. Monthly LCFS credit trading activity reports; 2018.
[87] California Air Resources Board. The LCFS credit price calculator – Alternative fuel toolkit; 2017.
[88] Google. Google Maps; 2018.
[89] U.S. Department of Energy Office of Energy Efficiency & Renewable Energy. Fact #621: May 3, 2010 Gross Vehicle Weight vs. Empty Vehicle Weight; 2010. [Online]. Available: https://www.energy.gov/eere/vehicles/fact-621-may-3-2010-gross-vehicle-weight-vs-empty-vehicle-weight [Accessed: 29-May-2018].
[90] California Air Resources Board. Low Carbon Fuel Standard Program | California Air Resource Board. [Online]. Available: https://ww3.arb.ca.gov/fuels/lcfs/lcfs.htm.
[91] California Air Resources Board. Monthly LCFS credit trading activity reports. [Online]. Available: https://ww3.arb.ca.gov/fuels/lcfs/credit/lrtmonthlycreditreports.htm [Accessed: 03-Aug-2020].