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Market prospects for biogas-to-energy projects in the U.S.A. based on a techno-economic assessment of major biogas sources in North Carolina

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A B S T R A C T

Current market potential for biogas-to-energy projects in the United States is analyzed based on levelized cost of energy (LCOE) estimates for producing renewable electricity, compressed natural gas (bio-CNG) and renewable natural gas at 2,837 landfills, wastewater treatment plants and swine farms in North Carolina having biogas resource potentials of 13 m^3/d to > 380,000 m^3/d. The LCOE estimates are generated using new approaches for modeling biogas collection from multiple sources via physical pipeline networks or tanker truck transport (a.k.a. "virtual" pipelines) in combination with recent production and cost functions published elsewhere. Whereas the LCOE estimates end up being significantly higher than 2022–23 prices for electricity and natural gas in regional U.S. energy markets, bio-CNG projects collecting > 100 MMBtu/d (1 MMBtu ~ 1 GJ) of biomethane yield LCOEs on par with recent prices for CNG for transportation of $26–$51/MMBtu. When incentives available through federal and certain state government programs are considered, sites in pipeline networks or in virtual pipelines with biomethane collection rates as low as 45 MMBtu/d could become economically viable. The results of this study help quantify the potential for monetizing an underutilized energy resource in the U.S. that can contribute to decarbonizing the nation's energy production.

Introduction

Biomethane in biogas generated from organic waste streams like municipal solid waste, wastewater, livestock and crop waste offers a sustainable alternative to fossil fuels for various purposes; from generating heat and electricity to fueling transportation and industrial processes [1]. Biomethane can be integrated into existing natural gas infrastructure [2], thus bolstering domestic energy security [3,4], and it can fuel backup generators for intermittent renewable energy sources like wind and solar to ensure reliable clean energy [5–7]. Additionally, capturing and combusting the 40 %–75 % of biomethane in biogas [8] reduces greenhouse gas emissions by oxidizing the biomethane, which has 100-year global warming potential 27–30 times that of carbon dioxide (CO_2) [9].

Biogas has proponents in many developing countries where conventional energy tends to be expensive and infrastructure for supplying rural areas and/or islands is lacking [10–12]. The largest producers of biogas and biomethane, however, are in Europe and North America, where production remains at just a fraction of these countries' potential, often despite government incentives [13,14]. In these regions, conventional energy is more affordable, and the infrastructure for delivering that energy connects to all but the most remote and least inhabited regions.

A case in point is the United States. The U.S. generates the most waste per capita [15] and ranks second only to China in both consuming primary energy [16] and producing greenhouse gas (GHG) emissions [17].

Abbreviations: AD, anaerobic digester; bio-electricity, electricity generated from biogas/biomethane; bio-CNG, compressed biomethane; CNG, compressed natural gas; CAPEX, capital expense; EPA, U.S. Environmental Protection Agency; GGE, gallon of gasoline equivalent; GHG, greenhouse gas; LCFS, California Air Resources Board Low-Carbon Fuel Standard Program; LCOE, levelized cost of energy; LMOP, EPA Landfill Methane Outreach Program; MSC, marginal supply curve; NC, North Carolina, U.S.A.; NMAE, normalized mean absolute error; ODM, organic dry matter; OPEX, operating expense; RFS, EPA Renewable Fuel Standard Program; RIN, RFS Renewable Identification Number; RNG, renewable natural gas (biomethane); SFPN, Swine Farm Physical Pipeline Network Modeling Scenario; SFVPBC, Swine Farm Virtual Pipeline Base Case Modeling Scenario; SFVP2X, Swine Farm Virtual Pipeline Costs-Doubled Modeling Scenario; VP, virtual pipeline; WWTP, wastewater treatment plant; WWTP1, WWTPs assumed to have an installed AD and flare system; WWTP2, WWTPs assumed to lack AD and flare system.

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At the same time, the U.S. is one of the world's largest producers of fossil fuels, and domestic energy prices are relatively low [18]. Furthermore, innovative policies for incentivizing biogas and biomethane production have been in place in the U.S. at the federal and state levels for over a decade, but investment in such production remains nascent, particularly compared to European counterparts Germany and Denmark [19].

For use of biogas/biomethane to expand significantly in the U.S., these fuels and/or the other forms of renewable energy that can be produced from them will need to become both more accessible and cost-competitive in the nation's wholesale/retail energy markets. While there are opportunities to increase use of biogas/biomethane at facilities that both process large volumes of organic waste and consume significant energy like wastewater treatment plants (WWTPs) [20–22], these are niche markets with limited growth potential. Much greater potential lies in selling renewable electricity on the national electric grid or injecting biomethane into the natural gas pipeline system. In these two markets, biogas/biomethane production has a far better chance of achieving cost reductions through economies of scale while offsetting fossil fuel use and decreasing fugitive GHG emissions from decomposing organic waste.

Here we update existing cost estimates for using biogas to produce renewable natural gas (RNG), bio-CNG, and biogas-generated electricity (bio-electricity), and then benchmark these new estimates against current prices for natural gas, CNG, and electricity in regional markets across the U.S. The cost of biogas/biomethane production depends on such factors as the type and amount of organic waste, and the technology needed to collect, process, and convert raw biogas into one of the three forms of energy being considered. To account for these factors, we estimate biogas-to-energy project costs at 11 landfills, 784 WWTPs and 2,042 swine farms in North Carolina (NC), a state that has been ranked as having the third-largest biogas resource potential in the U.S. [23] (Fig. 1). The three types of sites analyzed are the largest biogas point-sources in NC, with biogas potentials of as little as 13 m^3/d to almost 400,000 m^3/d [24]. Additionally, the concentration of swine farms in the eastern part of NC (Fig. 1C) allows us to explore the feasibility of achieving economies of scale by potentially networking the biogas output of multiple farms, either by pipeline or using tanker trucks.

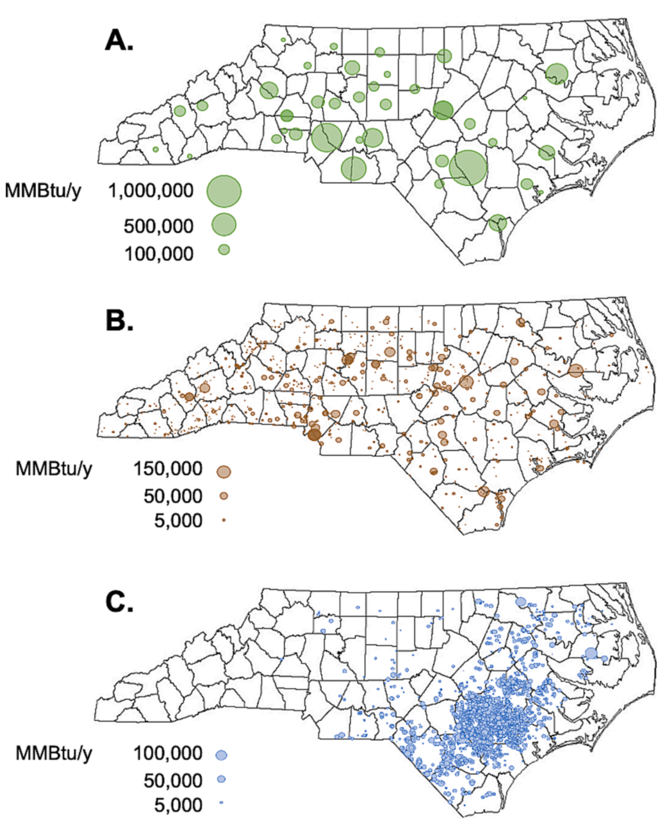

Fig. 1. Locations of (A) landfills, (B) WWTPs, and (C) swine farms analyzed. Dots marking locations are sized according to each facility's annual biogas production. Sizing is uniform across all three maps. Note that most swine farms are concentrated in the eastern part of the State. 1 MMBtu ≈ 1 GJ.

Previous assessments of biogas potential in the U.S. have gauged the status of anaerobic digestion of food waste [25], biogas production and utilization at WWTPs [26], the role that recent federal policy could play in increasing electricity generation from livestock farms [27], and the national waste-to-energy potential [14,23,28]. Of these, our analysis is most like that of Murray, et al. [14], who modeled aggregate marginal supply curves of biomethane and renewable electricity production for the entire U.S. based on the biogas potential of the same organic waste sources that we consider here along with livestock and crop waste.

Although our analysis involves a smaller, more geographically limited set of biogas sources, we have updated and expanded upon the work of Murray, et al. [14] by using the range in type and scale of prospective biogas projects in NC as a proxy for assessing the production potential and economic competitiveness of similar projects elsewhere in the U.S. We carry out this assessment in two ways. The first is to assemble marginal supply curves (MSCs) as a function of LCOE for producing bio-electricity, bio-CNG, and RNG in NC and evaluate the MSCs in the context of the State's recent consumption of and prices for electricity, CNG, and natural gas. The comparison suggests that the amount of energy that technically could be produced from biogas sources for commercial sale in the U.S. is likely smaller and more costly than previous estimates.

We then plot our LCOE estimates for individual bio-electricity, bio-CNG, and RNG projects as a function of collectable biomethane amounts and compare the LCOEs to recent prices for electricity, CNG, and natural gas in regional markets across the U.S. (New England, the Gulf Coast, the West Coast, etc.). We find that the greatest market potential for bio-CNG and RNG is as transportation fuel, a market that was just being established at the time of the study by Murray, et al. [14], and thus one they did not assess.

Methods and data

Systems overview

Biogas is collected at landfills (Fig. 2.A) using wells that feed into gathering pipelines, while at WWTPs (Fig. 2.B) and swine farms (Fig. 2.C), the collection is accomplished using anaerobic digesters (ADs) (Fig. 2.D). We assume that the ADs at WWTPs are one or more mixed digester tanks, while those at swine farms are covered in-ground lagoons into which the swine waste is washed.

After dewatering, further processing of the biogas depends on the form of energy it will be turned into. To generate electricity, secondary processing of the biogas involves chilling to precipitate out any water remaining as vapor and treating to remove sulfur and/or siloxane (Fig. 2.F.i). The gas is then compressed (Fig. 2.F.ii) and pumped into a generator that burns the gas as fuel (Fig. 2.F.iii) and feeds the bio-electricity into the grid (Fig. 2.G).

Conversion of biogas into CNG or RNG requires not only the secondary processing (i.e., chilling and siloxane/sulfur removal), but also additional treatments to remove CO_2, nitrogen, oxygen, and any volatile organic compounds in the gas (Fig. 2.H.i). Afterward, the gas, which is now pipeline-quality methane, is either compressed (Fig. 2.H.ii) for direct sale as a transportation fuel (bio-CNG) (Fig. 2.I) or injected into a natural gas pipeline (RNG) (Fig. 2.J) for sale to another party.

Systems modeling

Like in Murray, et al. [14], we size and cost the biogas collection systems for landfills (wells with gathering pipelines), WWTPs (mixing-

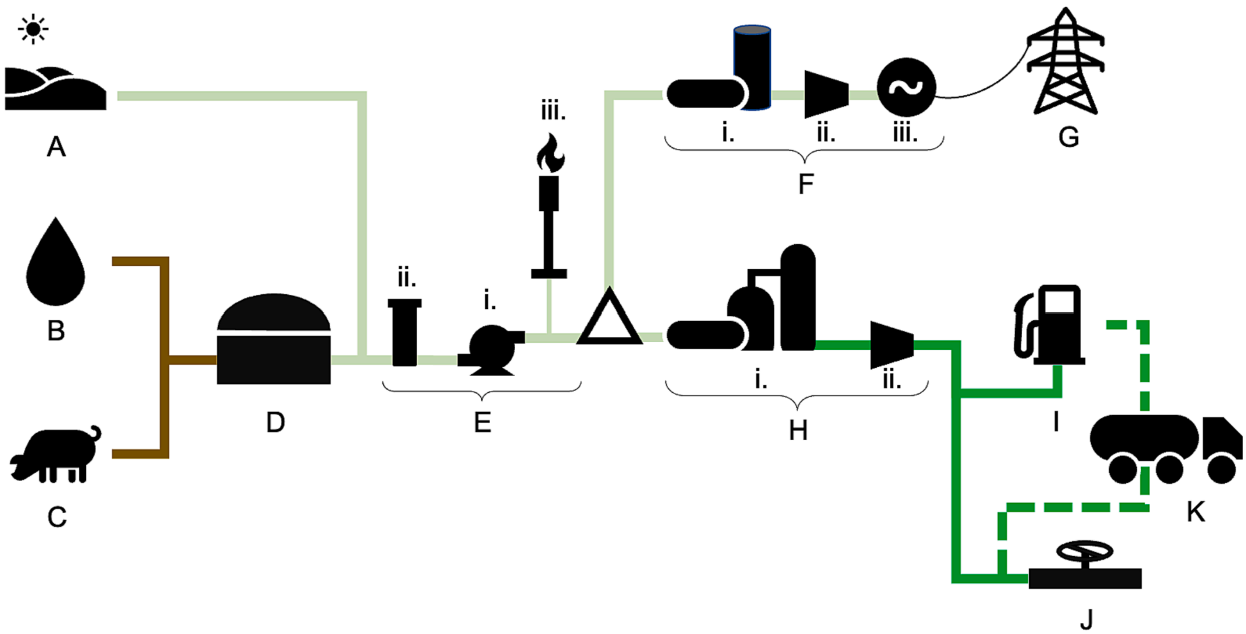

Fig. 2. Schematic of biogas collection and energy production systems analyzed in this study. Sources: (A) landfill, (B) wastewater, and (C) swine waste. Collection and primary processing system: (D) anaerobic digester, (E.i) blower, (E.ii) knockout pot, and (E.iii) flare. Bio-electricity production system: (F.i) secondary processing to remove water vapor, sulfur, and/or siloxane, (F.ii) compressor, (F.iii) electric generator, and (G) electric grid. Bio-CNG and RNG production system: (H.i) advanced processing to also remove CO_2, N_2, O_2, and any volatile organic compounds, (H.ii) compressor, (I) CNG station, (J) natural gas pipeline, (K) tanker truck.

tank ADs) and swine farms (covered, in-ground ADs) (Fig. 2A–C) using empirical functions from other sources. But whereas Murray, et al. [14] relied on functions in Krich, et al. [29], Cooley, et al. [30], ICF International [31], and Prasodjo, et al. [32], we use functions from more recent modeling tools, reports, and scientific studies. Functions for landfill wells and gathering pipelines are from the LFGcost-Web spreadsheet model (v. 3.5) created by the Landfill Methane Outreach Program (LMOP) of the U.S. Environmental Protection Agency (EPA) [33]. The functions for WWTP ADs are those developed by Michailos, et al. [34] and El Ibrahimi, et al. [35]. And the functions for swine farm ADs are from Parvathikar, et al. [24]. For the sake of brevity, all are provided in the supplemental information (SI, Section 2.1).

We model the remaining steps for transforming the collected wet biogas into either bio-electricity (Fig. 2.E-F-G), bio-CNG (Fig. 2.E-H-I), or RNG (Fig. 2.E-H-J) using empirical functions from the LFGcost-Web model [36]. We also use functions from the same model to estimate direct and avoided methane emissions reductions. Although they are in a model for landfills, these functions are for components that also make up the other types of biogas-to-energy projects we analyze. Again, for the sake of brevity, the functions are provided in the SI (Section 2.2). We note that the LFGcost-Web capital cost (CAPEX) functions and operation and maintenance cost (OPEX) functions for the different energy conversion technologies are suitable only for specific ranges of biogas production rates.[1] Consequently, we assume that if the flux of biogas at a prospective project (e.g., a landfill) is outside the specified range of a given technology (e.g., a standard turbine generator), that technology is not an option for the project.

Additional modeling for RNG systems

In the LFGcost-Web model, RNG project costs are valid only if the prospective project site produces biogas at high rates of 40,750–244,660 m^3/d. Furthermore, the model considers only the case of connecting the single site to a nearby natural gas pipeline using a dedicated RNG pipeline. However, existing RNG projects have been structured in at least two other ways. One achieves economies of scale from smaller biogas sources by using a network of pipelines to gather the output and send it to a central RNG processing site. The central site, in turn, is connected by an RNG pipeline to a nearby natural gas pipeline. This method has operated on a small scale in the Optima-KV project, a network of five swine farms in Kenansville, NC, that inject ∼ 80,000 MMBtu/y of RNG into an adjacent natural gas pipeline, where it is purchased by the electric utility Duke Energy [37]. The other approach involves first converting biogas into CNG. At an onsite fueling station, the CNG is then loaded onto a tanker truck that transports the fuel to an RNG injection site, where it is slightly depressurized and pumped into the line for sale (Fig. 3K). This type of "virtual pipeline" (VP) is being used by Smithfield's Ruckman Farm in Albany, MO, which is selling its ∼ 244,000 MMBtu/y production of RNG also to Duke Energy [38].

To assess these other ways of structuring an RNG project, we developed two additional modeling approaches. The more complex approach simulates the pipeline networking of multiple swine farms to a central RNG processing site. Similar models published by others indicate that such networking can be economically viable [32,37,39–44]. Our model differs from previous approaches in that it successively adds swine farms, from largest to smallest biogas potential, to networks that grow with each farm addition. In the process, the economics of the networks at each stage in their evolution are computed. This approach offers significant advantages over previous methods because it allows us to establish not only when during the growth of a network there are enough participating farms for the network to qualify for an RNG project, but also the point afterward at which the buildout achieves its lowest LCOE. Factored into this LCOE are (1) the cost of each pipe segment in the network based on its length and diameter as determined from the pressure in the pipe segment; (2) the cost of capture, primary processing, and compression of biogas at each farm in the network; and (3) the cost of the central RNG processing and injection sites for the network. Further explanation of how the model works is provided in the SI (Section 3).

[1] The functions include those for sizing and costing four different types of generators: a small reciprocating engine (100 kW–1 MW), a microturbine (30–750 kW), a reciprocating engine (>800 kW), or a turbine (>3 MW).

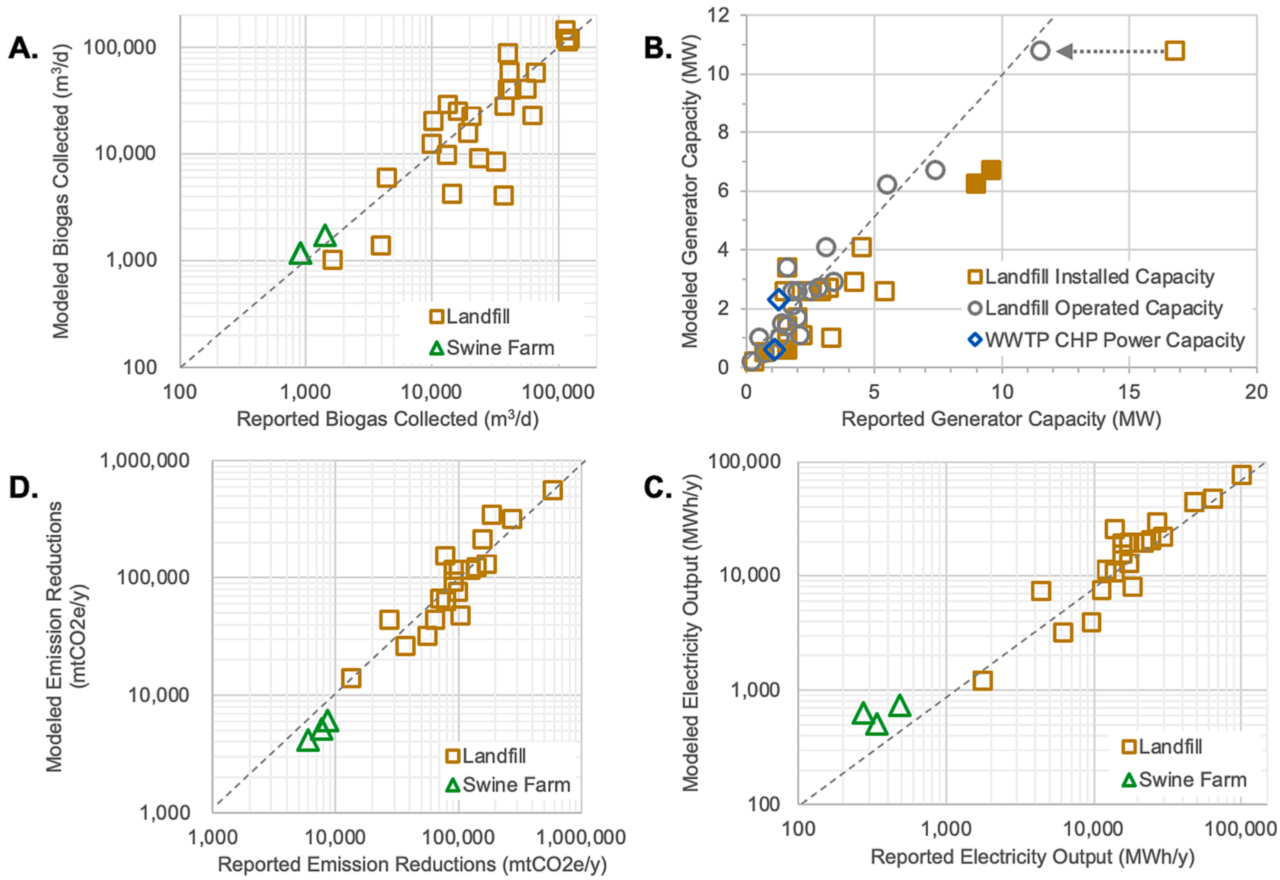

Fig. 3. Modeling results for NC sites already converting biogas into electricity as compared to reported values for (in clockwise order) (A) biogas collected, (B) installed and operated electric generator capacity, (C) annual electricity production, and (D) emissions reductions. Open squares in (B) represent correct predictions of generator type, while filled squares are predictions that differ from reported type. Dashed lines in plots delineate what would be a one-to-one relationship between modeled and reported values. Modeled values in all plots have a normalized mean absolute error of ≤ 35 %.

To model the VP RNG approach, we added the cost of tanker truck transport to a nearby injection site to our estimated bio-CNG production costs.[2] We evaluated two cases for this scenario. In the base case, we set transport costs to the 2021 marginal cost of trucking in the Southeastern U.S. of $1.16/km [47] and added a 15 % surcharge for unaccounted costs. The common distance we used in the base case was 18 km, which is the average driving distance between every swine farm and the nearest terminus of a natural gas transmission pipeline (i.e., a City Gate where an interstate pipeline connects with a local utility's distribution lines). Additionally, the median number of farms linked by shortest routes to a pipeline terminus is five, so every facility shipping to an injection site is assumed to pay one fifth of the injection site's one-time interconnection fee of $1.2 M plus an ongoing OPEX fee of $2.50/MMBtu (same as in the LFGcost-Web model for RNG projects). In the "2X" case, trucking costs and distances are doubled (to $2.31/km and 36 km, respectively), and the interconnection cost of an injection site is split between two rather than among five users. Using these two sets of inputs, we calculated a total LCOE for every swine farm that could produce enough biogas to meet the modeling threshold for a CNG project. For further details, see Section 4 in the SI.

Financial modeling

We evaluated the cost–benefit of each prospective biogas-to-energy project based on a project LCOE that we solved for using the same equation as in Murray, et al. [14], i.e.,

$$LCOE = \frac{\sum_{t=0}^{P}\left[\frac{(CAPEX_t + OPEX_t)}{(1+r)^t}\right]}{\sum_{t=0}^{P}\left[\frac{E_t}{(1+r)^t}\right]} \tag{1}$$

P in the equation is the project duration in years, t is project year, r is the project discount rate, and E is the annual amount of saleable energy produced by the project. We chose Eq. (1) over more sophisticated approaches to computing LCOE for its ease of use both in replicating the analysis results and in computing comparable LCOEs using different project durations and/or discount rates.

For this analysis, we set P to 15 years, the default project length in the LFGcost-Web model, and we fixed r at 8 %. This latter value not only aligns with commonly cited discount rates for renewable energy projects [48], but also yields LCOEs that are within 5 % of LCOEs produced using

[2] This approach differs from that of O'Shea, et al. [40], Sarker, et al. [45], and Ghafoori, Flynn [46], who assumed that the biogas source material (e.g., crop waste to animal manure) was transferred by truck or pipeline from a feedstock source to one or more hubs where the material was turned into biogas and upgraded (either there or elsewhere) to biomethane before being transported by truck or pipeline to a demand center.

a net present value (NPV) optimization method for LCOE [36,49] (Section 6 of the SI).[3]

Modeling input

The single input to the biogas-to-energy modeling was each source's annual biogas production. For landfills, production amounts come from the EPA LMOP database [33]. The estimates for annual biogas production at swine farms and WWTPs are those reported in Parvathikar, et al. [24]. The WWTP amounts are based on annual flows of treated wastewater given by the NC Department of Environmental Quality (NCDEQ) permitting database [50]. Harvestable biogas from these flows was calculated assuming an average mass of organic dry matter (ODM) per unit volume of wastewater of 0.94 kg/1,000 [51] and an average volume of biogas produced per unit mass of ODM of 500 L/kg [52]. A list of biogas potentials for all sources, along with additional information (e.g., waste accumulation rates at landfills, flow rates of water treated at WWTPs, and head and waste production at swine farms), is provided in the data and results tables (worksheets 1–3) in the SI.

Results

Modeling validation

We first constrained the accuracy of our modeling system using available data from landfills, WWTPs, and swine farms in NC with already operating biogas-to-energy projects. Of the 34 such sites listed in the data and results table provided with the SI (worksheet 4), 27 were of the type we modeled for this analysis, and all of them use biogas to generate electricity. The extent of quantitative information reported for these projects varied by biogas source, and none included financial information.

Reported and modeled amounts are compared in terms of biogas collected (Fig. 3A), installed electric generator capacity (Fig. 3B), annual electricity production (Fig. 3C), and total emissions reductions (Fig. 3D). The sites involved in the four comparisons are mostly landfills. There are three swine farms in three of the comparisons and two WWTPs in the fourth, the one for installed generator capacity. The comparison in the latter, however, is not direct because the WWTPs have combined heat and power (CHP) systems, systems not modeled here.

In all four comparisons, our modeling results exhibit a good one-to-one relationship with reported values. The systems modeling correctly predicts the type of generator for 84 % of the projects (Fig. 3B), while the normalized mean absolute errors (NMAE) of the predictions are 32 % for biogas collected (Fig. 3A), 33 % (28 % excluding outlier) for annual electricity production (Fig. 3C), and 29 % for annual emissions reductions (Fig. 3D). For installed generator capacity, the NMAE is a slightly larger 35 %, and the modeled capacities tend to increasingly underestimate installed capacities at landfills with higher biogas production rates (Fig. 3B). The LMOP database [33], however, reports not only installed capacities for these landfills, but also the average capacity the generators were operated at over the course of a year. When we plotted these operated capacities against the model results, which are based on the average annual amount of waste received by the landfills, the comparison improved considerably (Fig. 3B), dropping the NMAE for the predictions to 19 %. This suggests that the generators installed at the landfills have been oversized, presumably to handle projected future biogas production rates when annual waste deliveries become higher and/or the landfills approach being filled.

The comparisons in Fig. 3 suggest that at least when it comes to sizing project infrastructure, the systems modeling predictions are accurate to within 35 % across project scales spanning three orders of magnitude.

Marginal supply curves

As previously mentioned, NC ranked third for biogas potential in the U.S. in 2013, the last time such a survey was published the National Renewable Energy Lab [23]. NC is also a large energy consuming state. In 2022, the state was in the top ten in population, state gross domestic product (GDP), the manufacturing component of state GDP, and vehicle miles traveled in 2022 [53]. It was also twelfth in the U.S in total primary energy consumption, and in the top ten for consumption of gasoline and electricity. At the same time, per capita use of natural gas is among the lowest in the U.S. These contrasting attributes make NC an attractive case study for evaluating the role that locally produced biogas might be able to play in increasing sustainable energy production in the U.S.

Fig. 4 shows MSCs for bio-electricity, bio-CNG, and RNG constructed from our modeling results. Apart from landfills in Fig. 4C, only results for sites not known to already be producing energy are included in the MSCs. Due to uncertainty as to which WWTPs already have ADs and flares, two sets of results are shown for this source; one in which LCOEs include the CAPEX and OPEX costs for an AD and flare system (WWTP1), and in which the LCOEs do not (WWTP2). As noted previously, the production and cost functions from the LFGcost-Web model imposed constraints on the minimum and, in all but one case (turbine generators), maximum biogas flux needed to support a particular type of energy production. Consequently, the number of sites included in each plot differs. Additionally, since many sites qualified to produce bio-electricity with more than one type of generator (e.g., either a micro-turbine or a small reciprocating engine), only the project assessment with the generator that led to the lowest LCOE is plotted in the bio-electricity MSC. All modeling results are tabulated in spreadsheets 5–9 in the Excel workbook provided as part of the SI.

Because the range of biogas fluxes that qualified for modeling bio-electricity production was the most expansive, the number of qualifying sites for this type of project was the greatest. The MSC (Fig. 4A) includes 64 % of all swine farms analyzed, 23 % of all WWTPs, and 100 % of all landfills not already producing energy. Of these, the cheapest sources are landfills and WWTP2. The former and most of the latter appear capable of producing electricity at $\leq$ 10¢/kWh. Production is more costly at swine farms and WWTP1. The LCOEs at these sites start at around 20¢/kWh and climb to over 50¢/kWh. Production of electricity at all the sites would reduce their current GHG emissions by 77 %. This finding factors in not only direct methane emissions from the sources but also emissions avoided by displacing output from existing fossil-fuel generators in the state. The cumulative power capacity of all 1,527 potential biogas-to-electricity projects, however, would sum to less than 170 MW and produce just 1 % of the state's total annual electricity consumption in 2022 (1.8 million MWh vs. $>$ 140 million MWh [54]).

The bio-CNG functions in our model required higher biogas fluxes, leading to fewer qualified projects for this type of energy production. The sites include 64 % of the candidate landfills analyzed, 11 % of the WWTPs, and just 6 % of the swine farms. As a result, the total potential reduction in GHG emissions from all sources analyzed would reach only 33 % (Fig. 4B). The modeled production of bio-CNG exceeded one million barrels of oil equivalent per year (BOE/y) (Fig. 4B). This is slightly more than the amount of natural gas used for transportation in NC in 2021 [53], indicating that the state has more than enough biogas resources to meet recent vehicle demand for CNG. As with bio-

[3] Note that for landfill projects, annual energy output will change with time depending on when the landfill opened and when it is scheduled to close (see Tbl. SI-2), so using a fixed amount of energy production as in Eq. (1) will result in an LCOE that is up to 10% different from one calculated using the NPV optimization approach. For completeness, we included LCOEs computed both ways in the modeling results in the SI.

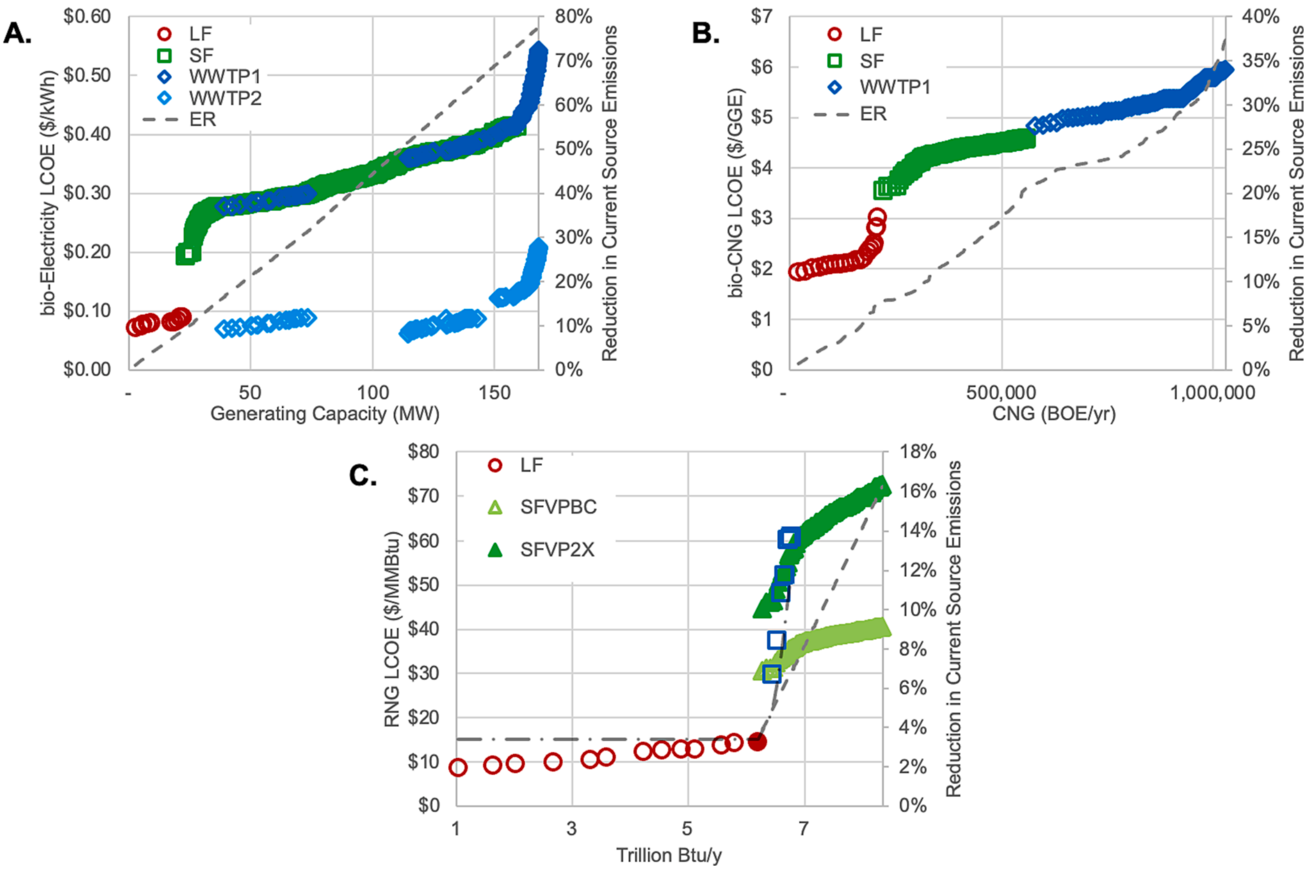

Fig. 4. Modeled marginal supply curves for (A) bio-electricity, (B) bio-CNG (BOE = barrels of oil equivalent), and (C) RNG (Note: 1 trillion Btu ≈ 1 million GJ). Also shown are the marginal reductions in GHG emissions (ER). Symbols correspond to biogas-to-energy project type: LF = landfill, SF = swine farm, WWTP1 = assumes no pre-existing AD and flare system, WWTP2 = assumes AD and flare system already in place. In C, SFVPBC is swine farm virtual pipeline base case, while SFVP2X is the 2X case.

electricity, we estimated that landfills and WWTP2 had the lowest production costs. LCOEs for these facilities were ~$2–$3 per gallon of gas equivalent (GGE).[4] Production at qualifying swine farms and WWTP1 would be more expensive. LCOEs at these sites started at ~ $3.50/GGE and rose to almost $6/GGE.

Direct production of RNG required the highest flux of biogas in our modeling. Of the all the sources analyzed, only one not currently producing energy, a landfill (solid red circle, Fig. 4C), met this criterion. Eleven other landfills already generating heat/electricity (open red circles, Fig. 4C), also met the criterion. In fact, one of these, the South Wake Landfill in Apex, NC, is in the construction phase of switching from electricity to RNG production [55].

RNG also could be produced among the sites we analyzed if sources were connected via physical or virtual pipelines. Again, because they are so densely concentrated in the eastern part of NC, we used only swine farms to assess these scenarios. Among the physical pipeline networks modeled, only six ended up collecting enough biogas annually to support direct RNG production (Fig. 4C). The largest and most costly of these involved 46 swine farms, while the smallest and lowest cost had eight farms. Importantly, these were the network extents that yielded both the minimum biogas flux needed for direct RNG production *and* each network's lowest LCOE. As more farms were added to the networks, LCOEs increased. These additional iterations of the networks are included in the SI, but only the lowest-cost versions of the networks are shown in the RNG MSC (Fig. 4C). The LCOEs for these were $30–$61/ MMBtu.

LCOEs for the virtual pipeline scenario were comparable. These values were $31–$41/MMBtu for the base case, and $45–$73/MMBtu for the 2X case (Fig. 4C). Under this scenario, however, cumulative production potential rose from 6.2 to 8.2 trillion Btu per year (TBtu/y), or ~ 1 % of total natural gas consumption in NC in 2022 (735 TBtu [53]), while potential reductions in total annual GHG emissions from all sources changed from 11 % to 16 %. This result occurred despite there being fewer swine farms involved in the virtual pipeline scenario than in the pipeline network scenario (124 vs. 181). The reason is that the former scenario involved only farms with biogas fluxes high enough to qualify for bio-CNG production, while in the latter scenario, smaller farms proximal to the pipeline networks got incorporated into them as they grew.

Project scale vs. cost competitiveness

The MSCs in Fig. 4 reflect both the cumulative amount of bio-electricity, bio-CNG, and RNG producible from biogas in NC, and the energy prices that in theory would attract investment in biogas-to-energy projects needed to achieve that potential. More difficult to establish from the MSCs, however, are the project scales and energy market(s) that would offer the greatest potential for economic viability, not just in NC, but also elsewhere in the U.S. Figs. 5–7 compare project LCOEs as a function of biomethane in the biogas collected to recent prices for substitutable energies in different regional U.S. markets and, where applicable, to major federal and state incentives that the projects would be eligible for.

In terms of bio-electricity, the most cost-competitive sites for project

[4] GGE = gallon of gas equivalent—i.e., volume of bio-CNG that equals the energy content of a gallon (3.8 L) of gasoline.

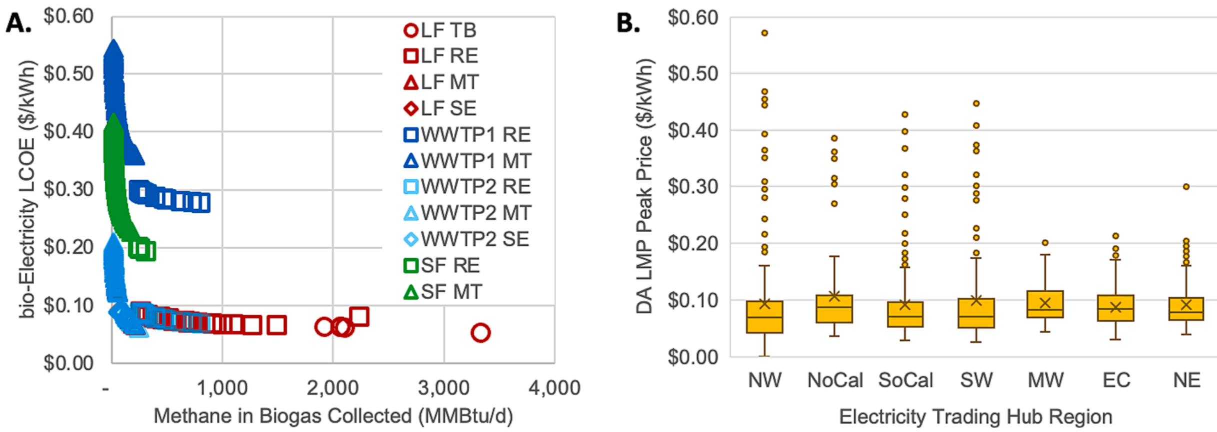

Fig. 5. A. Individual bio-electricity project LCOE estimates as a function of methane collected. Source abbreviations are the same as those in Fig. 4. Electric generator type: TB = combustion turbine, RE = reciprocating engine, MT = microturbine, and SE = small reciprocating engine. B. Box plot of peak day-ahead (DA) locational marginal electricity prices (LMP) at major regional electricity trading hubs during 2022: NW = Mid-C, NoCal = NP–15, SoCal = SP-15, SW = Palo Verde, MW = Indiana Hub, EC = PJM West, and NE = Mass Hub. Source: EIA [56].

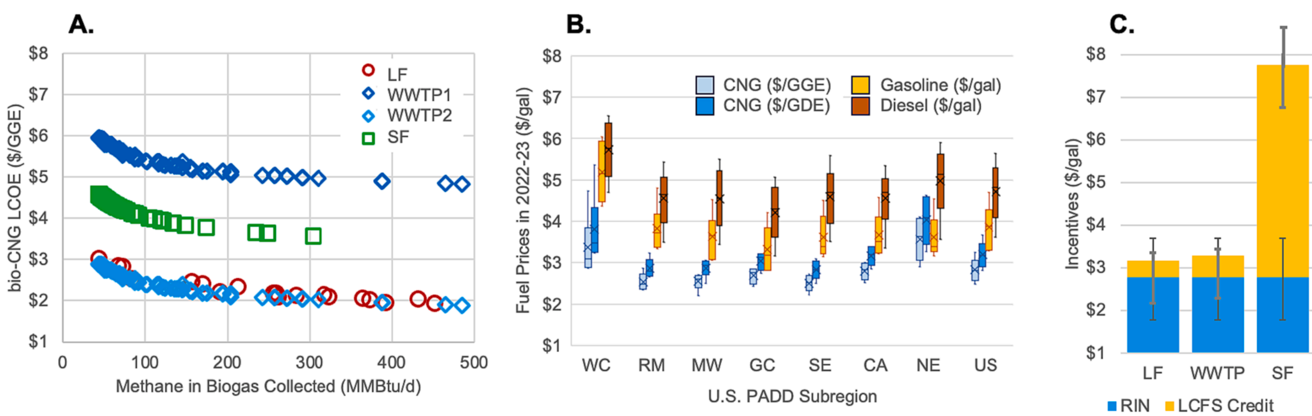

Fig. 6. A. Individual bio-CNG project LCOE estimates as a function of methane collected. Source abbreviations are the same as those in Fig. 4. B. Box plot of CNG, gasoline, and diesel prices in 2022 to mid-2023 in each of the seven U.S. PADDs and for the U.S. on average. PADD regions: WC = West Coast, RM = Rocky Mountains, MW = Midwest, GC = Gulf Coast, SE = Southeast, CA = Central Atlantic, and NE = New England. C. 2022 to mid-2023 value of major incentives available to qualifying bio-CNG projects expressed for each biogas source in $/GGE: USEPA RFS RIN, and California LCFS credit. Source: [57–62]. Note: 1 gallon = 3.8 L.

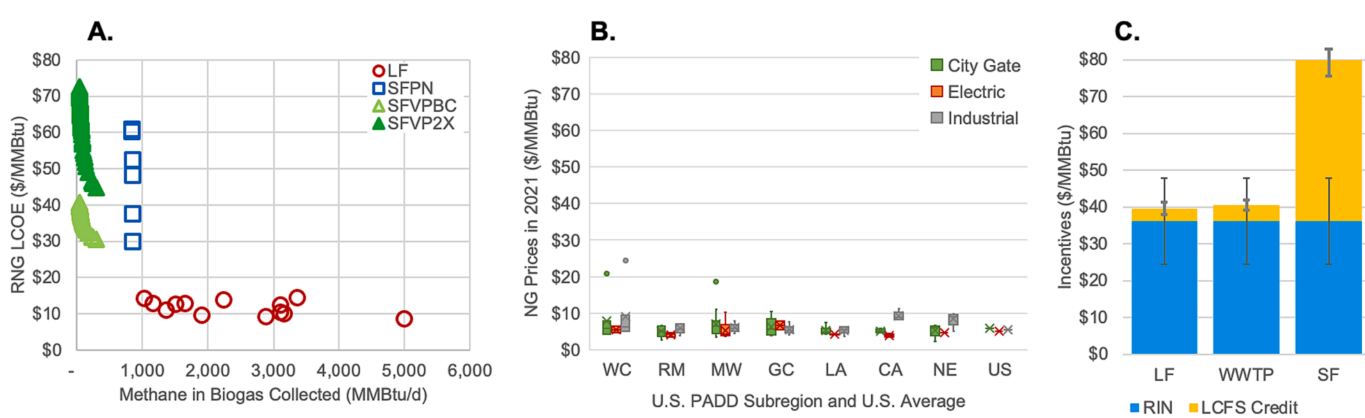

Fig. 7. A. Individual RNG project LCOE estimates as a function of methane collected. Source abbreviations are the same as those in Fig. 4. As discussed in text, swine farm pipeline networks that just meet the biogas flux needed to produce RNG are also the modeling point at which the networks achieve the lowest LCOE, which is why all these LCOEs are for the same level of biomethane collected. B. Box plot of natural gas prices in 2022 to mid-2023 in each of the seven U.S. PADDs and for the U.S. on average. See Fig. 6 for PADD regions. C. 2022 to mid-2023 value of major incentives available to qualifying RNG projects expressed for each biogas source in $/MMBtu. Source: EIA [64].

development were landfills and WWTP2 with methane fluxes of ~ 500 MMBtu/d or higher—i.e., fluxes large enough to fuel a reciprocating-engine or combustion-turbine generator. Estimated LCOEs at these sites were comparable to the 2022 median peak day-ahead locational marginal price for electricity at seven major electricity trading hubs located across the U.S. (midline in boxes, Fig. 5B). These prices, which are what utilities paid generators for electricity, are notably consistent among the trading hubs, indicating that on most days, day-ahead wholesale prices for electricity are relatively uniform across the U.S. Furthermore, the prices are far below those needed to support bio-electricity generation at WWTP1 and at livestock farms with methane fluxes equivalent to those of swine farms in NC. Presently, there are no major federal incentives for electricity generation from biogas. And while states with renewable portfolio standards (i.e., policies that require/encourage suppliers to generate a minimum amount of electricity from renewable energy sources) offer market incentives for renewable electricity, the type and maximum power capacity of generators that qualify for these incentives vary from state to state.

Greater market opportunity in the U.S. currently exists for bio-CNG projects. We found that such projects at landfills and WWTP2 would have LCOEs comparable to the recent price of CNG across all continental U.S. Petroleum Administration Defense Districts (PADDs) (Fig. 6A and 6B). This finding held regardless of whether the energy content of the CNG was expressed in terms of GGE or gallons of diesel equivalent. The higher LCOEs for bio-CNG produced at large livestock farms also appear cost-competitive with conventional CNG in at least two PADDs, the West Coast and New England.

Note that the LCOEs for bio-CNG are comparable to current market prices before inclusion of two significant incentive programs that the three types of bio-CNG projects analyzed here could apply to participate in. The first is the EPA's Renewable Fuel Standard (RFS). In this program, each gallon of bio-CNG produced from any of the three sources would, when sold, generate one D-3 Q-pathway renewable identification number (RIN) [63]. Bio-CNG producers can then sell their RINs to "obligated parties" (refiners and distributors) who must purchase enough of them for the fuel they sell to federally register as having a minimum required fraction of biofuel. During 2022 through mid-2023, D-3 Q RINS were selling on average for $2.78 ± $0.90[5]/gal, an amount greater than the LCOEs for bio-CNG from landfills and large WWTP2s, and an amount that when combined with the recent prices for CNG would meet or exceed the LCOEs of bio-CNG projects at livestock farms with methane capture rates exceeding 100 MMBtu/d (Fig. 6A and 6C).

The second major incentive program that bio-CNG projects can apply for is the State of California's Low Carbon Fuel Standard (LCFS). Because projects located outside California typically inject their bio-CNG output as RNG into a natural gas pipeline, we also considered the program in the context of the current market opportunity for RNG, which is shown in Fig. 7.

Across all seven PADDs, prices received for natural gas during 2022 to mid-2023, either at the City Gate or from electricity generators and industrial customers (i.e., lowest-cost buyers who receive natural gas directly from transmission pipelines), were about half of the lowest RNG project LCOEs in our analysis, i.e., those involving large landfills (Fig. 7A and 7B). If the gas is purchased explicitly for use as transportation fuel, however, sellers of RNG or bio-CNG that qualify for the RFS would also receive the same RINs discussed above, which when converted to gas units would equate to ~$36 ± $12/MMBtu (Fig. 7C). And, if the transportation fuel were being sold into California, sellers qualified for the LCFS would receive carbon credits that obligated parties in that state also would have to obtain in addition to RINs. The number of LCFS credits the sellers would receive depend on the carbon intensity (CI) of the seller's biomethane relative to that of gasoline or diesel (93 and 94 gCO_2e/MJ, respectively), where CI is the life-cycle emissions of each fuel per unit of energy. Based on current carbon intensities for active LCFS-approved projects producing RNG/bio-CNG from landfills, WWTPs, and swine farms, in combination with the value of LCFS credits sold during 2022 to mid-2023 ($85 ± $54/mt$CO_2$e), this additional incentive equates to $3.43 ± $1.64/MMBtu (or $0.39 ± $0.19/gal) for landfill biomethane, $4.40 ± $1.35/MMBtu (or $0.50 ± $0.15/gal) for WWTP biomethane, and $43.82 ± $4.51/MMBtu ($4.96 ± $0.51/gal) for swine farm biomethane (Fig. 6C and 7C). The greater value of RNG/bio-CNG from swine farms is due to their significantly lower life-cycle emissions, which have resulted in current CIs for active swine farm projects in the LCFS of –402 ± 40 gCO_2e/MJ (vs. 49 ± 29 gCO_2e/MJ for landfills and 38 ± 24 gCO_2e/MJ for WWTPs).

Thus, in the U.S., the most valuable market for biogas-to-energy projects is currently the transportation fuel market, especially the market in California where approved sellers can receive $40–$80 ± $13/MMBtu (or $3.17–$7.75 ± $1.41/gal, Fig. 6) on top of the going price for CNG. At such price levels, many to all the prospective bio-CNG and RNG projects in NC that we analyzed would be profitable, including large, high-LCOE WWTP1 projects.

Discussion

Although our techno-economic analysis considered only three types of biogas sources, all of which were limited to NC, the results have broader implications for the potential scale, markets, and cost competitiveness of biogas-to-energy projects in the U.S. Estimates for the total annual energy resource potential in the nation's organic waste range from 431 TBtu/y [23] to 815 TBtu/y [28] and possibly higher [14]. A recent report on biogas resources in North Carolina placed the state's potential at 45 TBtu/y (this excludes energy in crop waste, which is not currently extracted using ADs) [24]. Of this amount, 62 % (28 TBtu/y) is stored in landfills, WWTPs, and swine farms. Based on our modeling results, the fraction of energy from these same NC sources producible from qualifying projects lies between 22 % of their resource potential if the energy being generated is electricity (6.2 TBtu/y or 1,824 GWh/y) and 29 % (8.2 TBtu/y) if the energy is RNG. This finding implies that about a quarter of the U.S. biogas resource potential in animal manure, wastewater, and landfills, as well as industrial, institutional, and commercial organic waste (IIC), is technically recoverable for commercial sale. It further implies that the amount of natural gas that could be displaced by biomethane from these sources is likely < 1 % of the nation's natural gas consumption in 2022 (33,600 TBtu)[65], a percentage at least several times lower than previous estimates [14,23].

Relatedly, MSCs similar to those in Fig. 4A,C were developed by Murray, et al. [14] using data at the time from all U.S. states. Their MSCs projected that much of the nation's biomethane potential could be produced at an LCOE of $5–$6/MMBtu (1.7¢–2.0¢/kWh). In contrast, our LCOE estimates start at two or more times that level (Fig. 4A,C). This is partially the result of our having used a higher discount rate (8 % vs. 5 %) and shorter project length (15 y vs. 20 y) in calculating LCOE (eq. (1). Inflation since Murray, et al. [14] published their study is also a factor. However, calculating LCOE as they did and adjusting for inflation reduced our estimated LCOEs by only 17 %–24 %. Our still higher LCOEs may be due to our having used a smaller sample size of prospective biogas-to-energy projects, but because the set is still large and diverse, we suspect that our updated LCOEs are more realistic.

Nonetheless, producing energy from biogas is sustainable, reduces GHG emissions, and, at a large enough scale, can also be profitable, particularly in markets with incentives for boosting renewable energy production and/or reducing emissions. While many studies of biogas potential have focused on using the gas to generate electricity, our analysis makes clear that the far more attractive market for biogas-to-energy projects in the U.S. is transportation fuel. Wholesale electricity prices can certainly reach or exceed the bio-electricity LCOEs that we estimated (Fig. 5), particularly in the real-time market, but to receive these prices, biogas generators must either have must-run status or be

[5] Error = 2 × standard deviation.

dispatchable and thus able to store accumulating biogas/biomethane onsite until called upon. Furthermore, such peak prices tend to be relatively infrequent and short lived, so barring some form of regular payment, there might not be enough such events in a year for a bio-electricity project to break even.

In contrast, bio-CNG and RNG projects that succeed in selling their output as transportation fuel are more likely to generate a steadier, more predictable revenue stream, particularly if they can establish multiyear contracts for injecting their biomethane into a natural gas pipeline. And unlike for the bio-electricity results, there are at least two regional CNG markets in the U.S. where prices have recently exceeded the LCOE estimates for large biogas-to-biomethane prospects in NC even before including available incentives (Fig. 6A,B). When the value of RFS RINs is factored in, with or even without the added value of LCFS credits, even smaller, more expensive-to-develop biogas-to-fuel projects become profitable (Figs. 6 and 7). In fact, the incentives are so lucrative that they could attract existing bio-electricity projects to shift to producing bio-CNG. Possible examples include the landfill in Apex, NC [55], discussed previously, and the energy-intensive WWTPs currently selling bio-CNG into the LCFS program rather than using that energy to offset these facilities' own energy purchases [66].

Our analysis also suggests that like in NC, the national production potential of bio-CNG and RNG could meet or even exceed current demand for CNG in the U.S. A major reason for this result is the relatively low number of CNG vehicles in the nation. At present, these constitute < 0.1 % of the U.S. vehicle fleet (175,000 CNG vs. > 278,000,000 total [67,68]). And given the auto industry's shift toward producing electric vehicles (EVs), further growth of the CNG market in the U.S. will likely depend on greater adoption of heavy-duty CNG/LNG trucks [69].

Even so, both near- and long-term demand for biofuels looks to remain strong. The EPA has set volume targets for renewable fuel consumption through 2025, and given the current value of RINs, their future value could well remain in the tens of dollars per MMBtu. Similarly, the California LCFS program has been extended through 2030, and though the value of LCFS credits for landfill and WWTP biofuels could decline as the net CI of the state's fuel mix drops toward zero, the much lower CI of bio-CNG and RNG from livestock manure should ensure that the value of LCFS credits for qualifying projects of this type will remain high. Demand for bio-CNG and RNG is now also coming from more recently established LCFS programs in Oregon, Washington State, and the Canadian Province of British Columbia, and if proposed legislation in New York, Vermont, Michigan, Illinois, Minnesota and New Mexico is enacted, these states will implement LCFS programs as well [70].

Longer term, there are at least three emerging markets for biogas: (1) the "clean" (i.e., non-fossil-fuel derived) hydrogen market, (2) the sustainable aviation fuel market, and (3) a recently proposed update to the RFS program. The U.S. market for clean hydrogen, which can be produced from biomethane among other sources [71], is still nascent, but is now being accelerated by billions of dollars in federal funding that will be directed at developing regional clean hydrogen hubs, expanding the use of hydrogen in the industrial sector, and helping establish domestic hydrogen supply chains [72,73]. The DOE along with other U.S. federal agencies will also be issuing billions in federal funding to meet a shared goal of producing 3 billion gallons per year of domestic sustainable aviation fuel by 2030 and 100 % of projected aviation jet fuel use (35 Bgal/y) by 2050 [74]. Biomethane will be important source for achieving such targets [75]. And finally, the EPA has proposed an update to the RFS program that would allow electricity generated from biogas that is purchased for EV fleets to qualify for a new type of RIN, an eRIN [76]. The proposal is still under review, but if implemented, it would spur EV manufacturers to secure new power purchase agreements from biogas-fueled generators for all the manufacturers' existing and new light-duty vehicles.

Conclusions

We have used over 2,800 prospective biogas-to-energy projects in NC with potential biogas yields spanning five orders of magnitude to explore the possible scale, market potential, and current cost competitiveness of bio-electricity, bio-CNG, and RNG projects in the U.S. Among our principal findings is that the technical potential for producing commercially saleable energy from biogas is about one quarter of the total resource potential estimated for all sources analyzed. Project LCOEs are also higher than previous estimates and exceed current energy prices for electricity and natural gas in regional energy markets across the contiguous U.S. But whereas many previous studies have focused on using biogas to produce electricity, we find that LCOEs for bio-CNG projects collecting raw biomethane at rates of $\geq$ 100 MMBtu/d are most cost-competitive with recent prices for conventional CNG. And when key federal and state-level incentives are factored in, smaller bio-CNG projects with collection rates of as low as 45 MMBtu/d become economically viable as well.

Despite the economic incentives for project development available through the evolving RFS and expanding LCFS programs, adoption of biogas-based energy in the U.S. has been slow. Several areas of future research are needed to address this issue. Among the most important is improving the technical and thus economic potential for extracting energy from biogas and thereby also increasing reductions in GHG emissions. The low commercial energy recovery (~25 %) and low emissions reductions (~2% of total NC GHG emissions in 2022 for bio-CNG/RNG up to 8.5 % for bio-electricity [77]) estimated in this study are the result of many of the prospective projects having biogas yields that were too low for producing saleable energy, particularly bio-CNG and RNG. Research is also needed on policies for permitting the addition of RNG injection sites along natural gas pipelines. Federal U.S. legislation like the Public Utility Regulatory Policies Act (PURPA) and the Energy Policy Act of 1992 were critical in allowing renewable electricity generators access to the nation's electric grids [78]. A similar set of policies is now needed for more biogas projects to access the natural gas pipeline system. Establishing uniform policies, however, is likely to be difficult because most gas lines where injection sites would be needed are regulated by state public utility commissions, which often have different priorities, policies, and permitting processes. Criteria for identifying the best locations for injection sites also are necessary to minimize infrastructure costs, optimize biogas/biomethane transportation routes, and avoid adversely impacting local communities in which biogas-to-energy projects might be established. The last issue is of particular importance for projects relying on manure from industrial livestock operations [79]. In NC, for example, past pollution and health impacts to low-income Black and Latino communities surrounding large industrial hog farms has fueled opposition to producing energy from manure at these sites [80]. There is a critical need for research into whether and how energy projects at such farms could be developed to improve the local health, environment, and economy of adjacent communities if manure from such operations is going to be considered an acceptable source of sustainable energy.

CRediT authorship contribution statement

Lincoln F. Pratson: Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Writing – original draft, Writing – review & editing, Visualization, Project administration, Funding acquisition. **John Fay:** Methodology, Software, Visualization, Writing – review & editing. **Sameer Parvathikar:** Methodology, Validation, Writing – review & editing, Project administration, Funding acquisition.

Declaration of Competing Interest

The authors declare the following financial interests/personal

relationships which may be considered as potential competing interests: Lincoln Pratson reports financial support was provided by Duke Energy Corporation. John Fay reports financial support was provided by Duke Energy Corporation. Sameer Parvathikar reports financial support was provided by Duke Energy Corporation.

Data availability

Data has been provided as part of Supplementary Material.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.seta.2023.103557.

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