Advances in Applied Energy 5 (2022) 100089

Contents lists available at ScienceDirect

Advances in Applied Energy

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

Electrification potential of U.S. industrial boilers and assessment of the GHG emissions impact

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ARTICLE INFO

Keywords:
Industrial boiler dataset
Boiler capacity characterization
Electrification
Decarbonization
Greenhouse gas (GHG) emissions impact

ABSTRACT

Electrification is a key strategy for decarbonizing the industrial sector. Industrial process heating, which still relies heavily on fossil fuel combustion and accounts for the majority of sector wide GHG emissions, is a particularly attractive electrification target. Electrifying industrial boilers represents a cross-cutting opportunity for GHG emissions reductions, given their widespread use in most manufacturing industries. Yet, there are gaps in the understanding of the current population of conventional industrial boilers in the United States that preclude a characterization of boiler electrification's technical potential to reduce fuel consumption and GHG emissions. In this study, we develop an up-to-date dataset of the industrial boiler population in the U.S. and quantify the county-level electricity requirements and net changes in fuel use and GHG emissions under the current electric grid and theoretical future grid scenarios. Our results show an increase of 105 MMmtCO_2e and 73 MMmtCO_2e in GHG emissions from boiler electrification, with and without the replacement of byproduct fuels, respectively, under the current electric grid, and a reduction of 19 MMmtCO_2e and 7 MMmtCO_2e in GHG emissions under a future high renewables electric grid. GHG emissions savings are currently possible only in certain regions of the U.S. unless future grids are decarbonized. We also provide discussion that could be useful for policy makers and manufacturing facilities for advancing the electrification of industrial boilers in locations and industries toward fuel savings and GHG emissions reductions.

1. Introduction

Transitioning energy systems from fossil fuels to decarbonized alternatives is more urgent than ever given the ongoing rise in global greenhouse gas (GHG) emissions and their escalating effects on the climate. With future increases in GHG emissions expected to cause additional warming of the planet [1], the immediate deployment of commercially available clean energy technologies is vital [2]. The electrification of industrial process heating is one such solution to decarbonizing a sector heavily reliant on fossil fuels. While industry has so far remained a difficult sector to decarbonize due to its wide array of products and processes and long-lived, capital-intensive process equipment stocks [3], industrial boilers represent a cross-cutting technology with significant potential for electrification.

With the second highest industrial energy consumption globally as of 2019, the U.S. is an important target for industrial decarbonization [4]. In the U.S., manufacturing industries are responsible for 21% of all energy-related GHG emissions, and process heating accounts for 31% of GHG emissions within manufacturing, as of 2018 [5, 6]. Although industrial heating applications can vary largely across manufacturing industries, in most cases they rely on fuel combustion for both direct-fired process heating and steam production [7]. Conventional boilers are used for steam production in almost all industries and consume roughly one third of the fuel used for process heating in manufacturing [8]. A large share of boiler fuel use is from natural gas (34%) and coal (11%), but a majority (54%) comes from other fuels, including biomass and byproduct fuels, such as black liquor, still gas, and waste gas [8–12]. Switching from fuel-based boilers to electric boilers, may provide a straightforward and substantial opportunity for emissions reductions in many industrial plants.

The electrification potential (the amount of electricity required by electric boilers to meet steam demand) of U.S. industrial boilers and the emissions impact of boiler electrification depend largely on the current stock of conventional boilers and their fuel sources. However, the most recent set of published data on U.S. industrial boilers with key characteristics of industrial subsectors, installed capacity, and fuel types is from 2005 [13], whereas both the structure and energy use characteristics of the U.S. manufacturing sector have since changed substantially.

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https://doi.org/10.1016/j.adapen.2022.100089
Received 14 December 2021; Received in revised form 12 February 2022; Accepted 12 February 2022
Available online 16 February 2022

In addition, this previous characterization of boilers is limited in scope and coverage, reporting boiler capacity ranges and fuel types separately for only five subsectors – food, paper, chemicals, refining, and metals – and relying on top-down estimations rather than bottom-up accounting of individual boiler units. It also lacks data on the geographic distribution of conventional industrial boilers, which is essential for evaluating the electric grid emissions associated with electric boiler operations as well as locally available renewable electricity.

While an updated inventory of industrial boilers with technical and geographic detail is needed to provide the basis for current boiler technologies and steam demand, additional assessments of electrified heating technologies and conventional boiler fuel use are also needed to quantify the country-wide energy and emissions effects of electrification. Previous studies have documented the benefits of electrification in industry and identified boilers as a top cross-cutting opportunity [14–17]. Electric boilers have high thermal efficiency (~99%), fast ramp-up times, and low downtime [14] and require no onsite pollution abatement, combustion accessories, such as tanks, fuel links, and exhaust flues, or expensive combustion inspection [18]. They can also offer other non-energy benefits, such as lower capital, maintenance, and administrative costs and physical footprints, but the high cost of electricity relative to natural gas and other fuels has affected their economic feasibility [14]. Electric boilers could significantly increase the electricity load at industrial plants [14] [15], but they can also be operated flexibly to utilize low-cost power supply from renewables [16] and support increased renewable generation [17]. Heat pumps are another important technology for electrified hot water and steam, but they require waste heat from other processes and, thus, are out of scope since this study focuses on drop-in stand-alone boilers. While heat recovery is often already integrated in U.S. facilities for preheating makeup water or in economizers, waste heat for export, such as district heating, could be considered in other countries. This analysis on electric boilers can be useful for future comparisons to heat pumps and other electrotechnologies.

Recent studies assessing the energy and emissions implications of electrifying industrial heat in Germany [19] and in Europe [20] show that emissions savings from electrification are possible only under scenarios where electric boilers are operated in a hybrid setup with renewable electricity or from an electric grid with low carbon intensity. Schüwer et al. calculate an increase of 0.2-0.6 MMmtCO_2e/year from electrifying industrial boilers in Germany in 2020 and a decrease of 5.9-15.9 MMmtCO_2e/year in 2050, assuming an 80-95% reduction in electricity carbon intensity in 2050 [19]. Several reports centered on U.S. electrification of industry evaluate electric boilers, but either assume limited adoption relative to other electrotechnologies [21] or simplify their accounting of fuel use in a high-level, national analysis [22]. Hasanbeigi et al. estimate savings of 140 TBtu in final energy of industrial boilers and an initial increase in CO_2 emissions, followed by a decrease of 1,000 MMmtCO_2/year by 2050, assuming future grid decarbonization [22]. However, these findings based on aggregated national manufacturing energy data [23] exclude fuels categorized as "other," such as biomass and byproducts used as fuel, in its boiler energy use estimations as well as the additional power plant fuel energy inputs required for electrification.

Since the composition of primary energy sources in the current electric grid differs widely by region within the U.S., a spatial analysis pairing the locations of industrial boilers and regional makeups of the electric grid is needed to provide a more accurate and location-specific estimation of electrification potential. To date, there has been no detailed study on the county-level electrification potential and emissions impact of industrial boilers that also considers the current boiler capacity and fuel type distribution.

This study makes two novel contributions toward understanding the energy and emissions effects of widespread industrial boiler electrification in the United States. First, we develop a comprehensive and up-to-date dataset that characterizes the total population of conventional industrial boilers by county, industrial subsector, installed capacity, and fuel type. Our research integrates multiple national facility-level emissions databases and accounts for remaining boilers based on county-level fuel estimates. Second, we calculate the county-level electrification potential and GHG emissions impact for industrial boilers under multiple electric grid scenarios, considering both the additional fuel use and emissions from electricity generation. This research addresses key knowledge gaps about the climate change mitigation potential of electric boilers and highlights the need for further analysis around assembling facility-level equipment, fuel use, and emissions data from publicly available yet non-standardized data sources.

2. Methods

This analysis extends previous work documented in [24] to achieve two research outcomes: (1) developing a comprehensive and public dataset that characterizes the current stock of conventional industrial boilers in the U.S. and (2) calculating net changes in fuel use and GHG emissions from boiler electrification under different electric grid scenarios.

The methodology for creating our industrial boiler dataset requires integrating data on boiler units reported in the following national emissions databases: the U.S. Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP) [25], the Boiler Maximum Achievable Control Technology (MACT) Draft Emissions and Survey Results Database [26], and the National Emissions Inventory (NEI) [27]. To account for boilers not reported in the above databases, estimates of county-level fuel use from the National Renewable Energy Laboratory (NREL) manufacturing thermal energy use dataset [8] are used for deriving the populations and characteristics of remaining boilers. Manufacturing thermal energy use data are then applied to calculations of electrification potential, defined in Section 2.3, by U.S. county and industrial subsector. Net changes in GHG emissions are calculated from emissions factors of fuels avoided and fuels required for electricity, as well as the GHG emissions associated with current and future electric grids.

This section further describes the primary data sources, the process of data integration, and the methods and assumptions used to quantify the electrification potential and net changes in GHG emissions.

2.1. Data sources for industrial boiler characterization

Descriptions of the GHGRP, MACT, and NEI databases and the categories of data included in this study are described in Table 1, and the process of integrating data is described in Section 2.2.

The NREL manufacturing thermal energy use dataset provides county- and industry-level fuel use estimates for conventional boilers, combined heat and power (CHP), and process heating for the year 2014, and is derived from the emissions reporting from the 2014 GHGRP and U.S. Energy Information Administration 2014 Manufacturing Energy Consumption Survey (MECS) data. These fuel use data are used to estimate the populations of conventional boilers not reported in the databases summarized in Table 1.

2.2. Data integration and development of industrial boiler dataset

While the GHGRP, MACT, and NEI databases all supply unit-level characteristics of facility location, subsector, installed capacity, and fuel type, each is organized in a different structure, and integrating the relevant characteristics of boiler units involves a series of data filtering and cross-checking operations. The databases are independent but not necessarily mutually exclusive, meaning that individual boiler units could be present in more than one database and, thus, a process of cross-checking is required to identify and remove duplicate entries.

Fig. 1 summarizes our process for the integration of emissions databases and manufacturing fuel data. The full process flow diagrams and additional details on assembling the inventory of reported boilers

Table 1
Descriptions of the GHGRP, MACT, and NEI databases [28–30].

	GHGRP	MACT	NEI
Main data reported	Unit-level GHG emissions (CO_2, CH_4, N_2O)	Unit-level air pollutants (CO, NOx, PM, SO_2)	Unit-level emissions and air pollutants (VOCs, PM, metals, GHGs, etc.)
Reporting requirements	Mandatory for facilities that generate at least 25,000 mtCO2e/year	Survey	Submitted data provided by State, Local, and Tribal air agencies and supplemented data from U.S. EPA
Reporting frequency	Annual, since 2010	Once, in 2012	Every three years, since 2008
Database category relevant to industrial boilers	Emissions by Unit and Fuel Type: General Stationary Fuel Combustion (Subpart C)	Inventory: Major Source Boilers and Process Heaters	NEI point sources
Data characteristics relevant to this study	Facility ID, NAICS code (6-digit), reporting year, unit name, unit type, unit input capacity (MMBtu/hr), unit fuel type	Facility ID, NAICS code (3-digit), unit ID, unit type, unit design capacity (MMBtu/hr), unit fuel category	Facility ID, NAICS code (6-digit), reporting period, unit ID, unit type, unit design capacity, unit description (for fuel type)
Number of line items in relevant database category	253,683	8,320	8,202,877
Number of boilers from source in final dataset	794	4,412	13,988

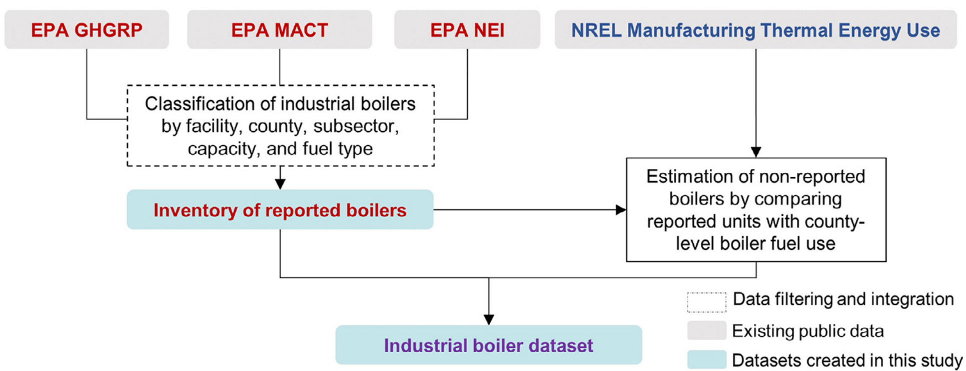

Fig. 1. Flow diagram of data sources and integration for assembling the industrial conventional boiler dataset.

and final industrial boiler dataset are described further in the supporting information (SI) Figures S1 and S2.

With GHGRP data, boilers are selected based on "unit type," "unit name," and North American Industry Classification System (NAICS) codes 31-33, representing the U.S. manufacturing sector. MACT data are likewise filtered for manufacturing NAICS codes and for unit types of industrial boilers, and these are merged with GHGRP boilers by facility, county Federal Information Processing Standards (FIPS) codes, and boiler capacity, and duplicate units are removed. Similarly, NEI boiler data are filtered by NAICS code and unit type, but also through text search for boilers listed by other unit types, such as "other combustion" or "other process equipment," and are then merged with the existing inventory by facility, county FIPS codes, and boiler capacity, with duplicate units removed. CHP boilers are not included in our industrial boiler dataset because replacement or hybridization with electric boilers would significantly affect the electricity generation and economics of CHP operations; consideration of these important effects is beyond the scope of this study. Boilers identified in the EPA databases are checked against a database of industrial CHP facilities, as detailed in Form EIA-923 [31], and CHP boilers are removed.

After devising an inventory of reported units, the remaining (i.e., non-reported) count of boilers per county is estimated by comparing boiler fuel use in each county and subsector, as indicated by the NREL manufacturing thermal energy use dataset, to the maximum boiler fuel use possible from boilers in the inventory of reported units. The equation to calculate the maximum possible boiler fuel use of reported boilers in the inventory, F_{inv}, per county and subsector, is based on the total installed capacity of reported boilers within the county and NAICS subsector, $C_{c,N}$, and reported operating hours per subsector, t_N, shown in Eq. 1. Operating hours data are taken from the GHGRP and averaged for each subsector.

$$F_{inv} = C_{c,N} * t_N \tag{1}$$

We encounter two cases when estimating the counts of non-reported boilers per county and NAICS code: (1) there is boiler fuel use as indicated by the NREL thermal energy use dataset but no reported boilers in our inventory from the Table 1 databases, and (2) there is greater fuel use indicated in the NREL dataset than what reported boilers are estimated to consume according to Eq. 1. In case (1), the count of non-reported boilers, b, is estimated based on the boiler fuel use, $F_{c,N}$, operating hours, and median installed boiler capacity per NAICS subsector, C_N, shown in Eq. 2. The median installed boiler capacity is used in Eq. 2 to reduce the influence of outliers in data where there are no reported boiler data as in case (1), whereas the average installed boiler capacity is used when reported boiler data are available for the county and subsector. In case (2), the count of non-reported boilers is estimated based on the difference between boiler fuel use and the maximum boiler fuel use of reported boilers in the inventory, operating hours, and average installed boiler capacity per county and NAICS subsector, $C_{c,N}$, shown in Eq. 3.

$$\begin{cases} \textit{Case 1:}\ F_{inv}(=0) < F_{c,N}\ ; & b = \dfrac{F_{c,N}}{t_N * C_N} & \text{(Eq. 2)} \\ \textit{Case 2:}\ F_{inv} < F_{c,N}; & b = \dfrac{(F_{c,N} - F_{inv})}{t_N * C_{c,N}} & \text{(Eq. 3)} \end{cases}$$

To account for the boiler capacity values of non-reported boilers, we assume a boiler capacity distribution for the non-reported boilers that reflects the capacity distribution of reported boilers with low boiler capacity ranges (<10 MMBtu/hr and 10-50 MMBtu/hr) per subsector. The distribution of low boiler capacity ranges is used here to account for smaller boilers often overlooked by national databases, which by design capture large units more frequently. Fuel types of the boilers are similarly determined based on the distribution of boiler fuel types per subsector. For non-reported boilers within a county and subsector, the fuel type is estimated according to the percentage of fuel type weighted by boiler energy consumption.

Table 2
Conventional boiler efficiencies by fuel type [34–36].

Boiler fuel type	Efficiency (%)
Natural gas	75
Coal	81
LPG & NGL	82
Diesel	83
Residual fuel oil	83
Coke & breeze	70
Other	70

2.3. Calculations of electrification potential and net changes in boiler fuel use and GHG emissions

Electric boilers are a commercialized technology that pass an electric current through the water between electrodes (electrode boilers) or through immersed heating elements (electric resistance boilers) to produce steam and hot water [32]. While electrode boilers tend to have higher maximum capacities, up to 335 MMBtu/hr, than electric resistance boilers, the efficiencies of both electric boilers are nearly 100% [33]. Electric boilers are also generally more compact than fossil fuel boilers, allowing parallel electric boilers to be viable options for replacing single larger fossil fuel boilers. In our calculations of electrification potential, we therefore assume that electric boilers can fully replace the steam demand from conventional fossil fuel boilers. We also note that the small amount of electricity inputs for boiler controls for both fuel and electric boilers is excluded in our calculation of electrification potential, as the percentage is negligible compared to fuel or electricity directly used for thermal energy. We further assume that sufficient grid capacity exists to enable full boiler electrification in our scenarios, but future studies should consider marginal demand implications on local grids to further assess technical feasibility.

The methodology for calculating the technical potential of boiler electrification is based on previous work that analyzed opportunities for solar industrial process heating, including the use of photovoltaic electricity for electric boilers [24]. From the same NREL manufacturing thermal energy use data, the fuel use for conventional boilers is characterized by county, NAICS subsector, and fuel type and, along with considerations of efficiency losses from fuel combustion, is used to determine the steam demand met by existing boilers.

The electrification potential is defined as the amount of electrical energy required by electric boilers to meet steam demand, and is calculated based on the following equation:

$$E = F_{c,N,f} * \eta_{b,f} * \frac{1}{\eta_e} \tag{4}$$

Where E is electrification potential (MWh), $F_{c,N,f}$ boiler fuel demand per county, NAICS subsector, and fuel type, $\eta_{b,f}$ conventional boiler efficiency by fuel type, and η_e electric boiler efficiency. Conventional boiler efficiencies can vary from boiler to boiler depending on boiler configurations and operating practices, but due to lack of data on individual operations, we assume average nationwide boiler efficiencies dependent on its fuel type (Table 2). Electric boiler efficiency is assumed to be 99% [32].

With the county-level electrification potential, we then calculate net changes in GHG emissions by considering the fuel avoided from conventional boilers as well as the makeup of regional electric grids to account for the source of electricity and their associated emissions. The amount of power plant input fuel required to meet electricity demand is calculated from heat rate values from the EPA's 2019 eGRID database [37] and the resource mix of fuels used in regional electric grids and accounts for grid losses (Fig. 2). Resulting emissions are calculated based on full fuel cycle GHG emissions factors by fuel types, according to EPA combustion emissions factors for GHG inventories [38] and fuel cycle emissions factors from the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model [39]. Emissions from non-fossil sources are assumed to be zero, as the life cycle emissions factors for these electricity generation technologies are a tiny fraction of fossil fuel-based technologies [40].

Net changes in GHG emissions are calculated for each county with the current electric grid and in two potential future electric grid scenarios. Further descriptions of the resource mixes of the electric grids are provided along with results in Section 3.3. In calculating net fuel use and GHG emissions changes, we note several assumptions about the electrification potential, fuel consumption for electricity, and emissions factors. First, the electricity required for electric boilers is based on boiler energy demand from 2014, which is assumed to the same in the year of the electrification analysis for the current grid (2019). Second, the fuel consumption for electricity required by electric boilers is based on power plant heat rate and resource mix data within an eGRID subregion, as opposed to smaller regions of the power grid or larger interconnected regions. Third, average emissions rates for each fuel type are used instead of marginal emissions rates. Although the calculations of electrification potential and GHG emissions impact is for industrial boilers in the U.S., our methods and data considerations can be extended to future technical potential analyses in other countries where the electrification of the industrial sector is important.

3. Results and discussion

3.1. Industrial boiler characterization

The inventory of reported boilers with complete information on location, subsector, capacity, and fuel types amounts to 18,954 units. As discussed previously, there are also many non-reported units, especially low-capacity boilers, that are not surveyed or monitored in the Table 1 emissions databases. Combining the estimated count of non-reported boilers from our method using county-level fuel use and the reported boilers, the total number of conventional industrial boilers is estimated to be 38,537. Their distributions among manufacturing subsectors and by boiler capacity ranges is shown in Fig. 3. The total number of boilers is compared to the estimated count of industrial boilers from 2005 [13] and to the number of U.S. manufacturing establishments overtime [41] to assess the validity of our results. These and additional comparisons between our assessment and [13] are described further in the SI.

The food and chemicals subsectors have the highest estimated number of boilers with similar capacity distributions, where the majority of boilers falls into the low-capacity ranges (<10 MMBtu/hr and 10-50 MMBtu/hr). The large number of boilers in the food subsector reflects both the quantity of food manufacturing establishments – second most among all the manufacturing subsectors – and a high steam demand for a wide variety of process heating applications [42]. Its large portion of low-capacity boilers can be attributed to a high percentage of small-sized food manufacturing facilities – 80% of food manufacturing establishments have employment totals of less than 50 people [41]. According to U.S. DOE Industrial Assessment Centers (IAC) which provide technical assessments of manufacturing plants, energy usage is generally higher in plants with a larger employment size [43]. Similarly in the chemicals subsector, while commodity chemicals are produced in bulk in large-scale facilities, there are also numerous smaller and more differentiated facilities for specialty, agricultural, and consumer product chemicals that require various levels of steam demand, and thus, a high percentage of low-capacity boilers [44, 45]. The paper subsector has a considerably large number of boilers that are high-capacity (>250 MMBtu/hr) as pulp and paper mills tend to be large facilities, where nearly 50% of paper manufacturing establishments have employment totals of 50 or more people [41], with many steam-intensive processes [46].

The paper, chemicals, food, and refining subsectors have the largest overall installed capacity of industrial boilers. These four subsectors also

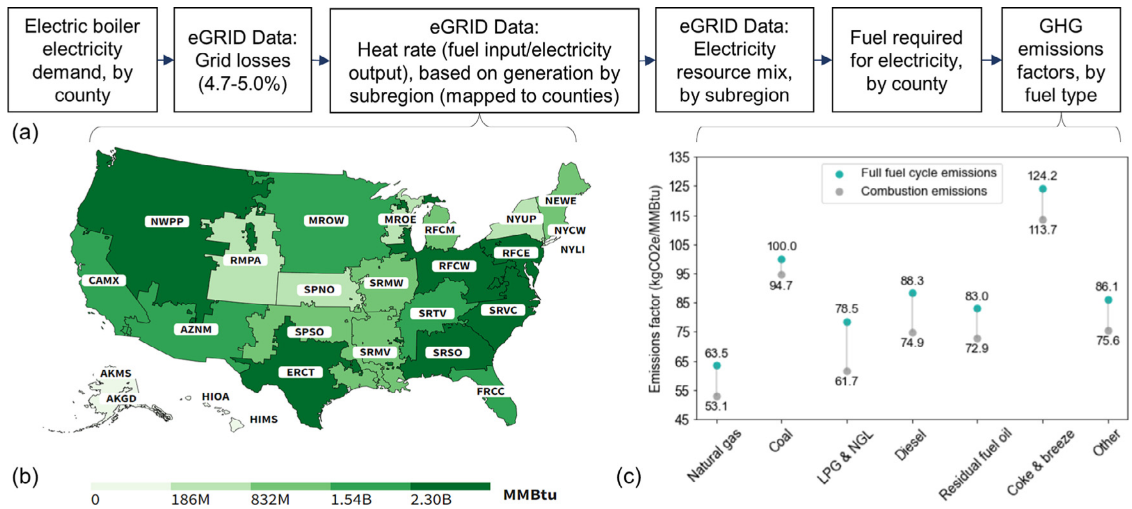

Fig. 2. (a) Flow diagram for calculating annual net change in GHG emissions of boiler electrification with **(b)** eGRID electricity heat rate data [37] and **(c)** GHG emissions factors for the full fuel cycle including emissions from combustion and upstream processing.

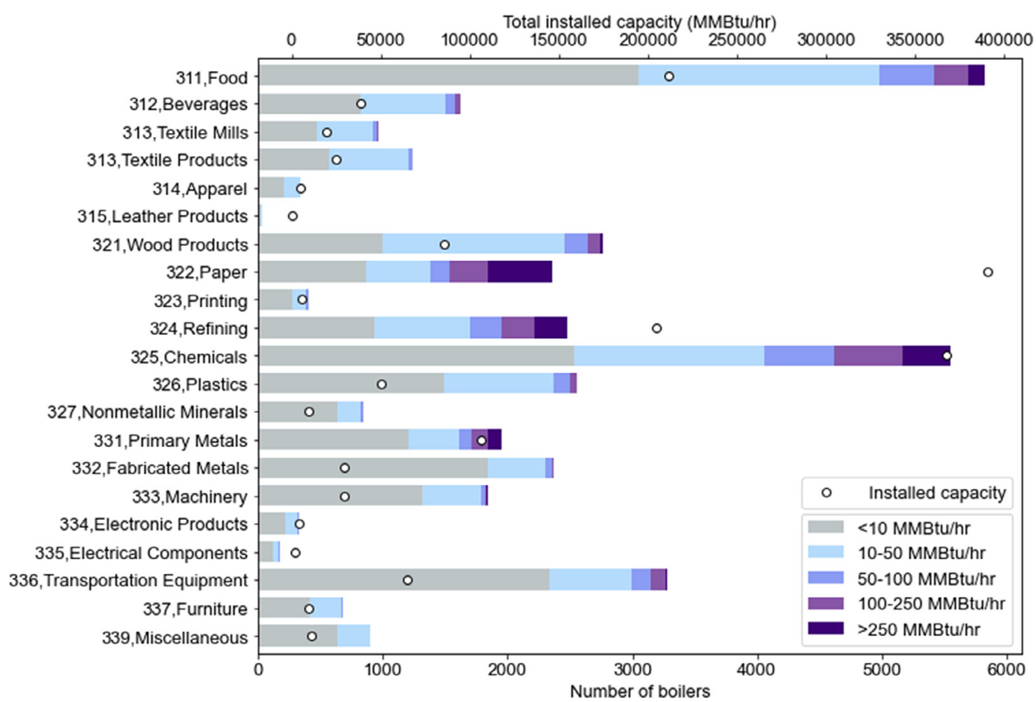

Fig. 3. Estimated distributions of industrial boilers by NAICS manufacturing subsectors and capacity range.

have the highest steam demand for process heating in U.S. manufacturing [42], as well as a large number of high-capacity boilers. However, operational parameters, such as boiler capacity utilization, which can differ by subsector and individual facilities, determine fuel consumption totals that ultimately affect potential for electrification and emissions reductions. Boiler fuel types likewise affect which boilers can be practically substituted with electric boilers as well as the net changes in emissions.

The fuels used in industrial boilers consist of natural gas, biomass, coal, oil products (fuel oil, diesel, LPG), and other fuels (still gas, waste gas, solid byproducts). The share of these fuels varies significantly among manufacturing subsectors (Fig. 4a) and depends on both regional fuel costs and the availability and utilization of byproducts from certain manufacturing processes. For example, the petroleum refining subsector uses still gas and petroleum coke as byproduct fuels for over 60% of its onsite fuel consumption [10]. Similarly, the wood and paper subsectors use black liquor, a biomass byproduct of the Kraft process for converting wood to pulp and paper [47], for 40% of its onsite fuel consumption [9]. In the iron and steel industry, blast furnace and coke oven gases make up 27% of fuel consumption [12], although fuel use for boilers and steam demand are comparatively small. The use of byproduct fuels complicates the feasibility of boiler electrification in certain subsectors because facilities would have the added cost of purchased electricity as well as selling or disposal costs for the stranded byproducts. In other sectors which use wastes as fuel, such as municipal solid waste in waste-to-energy applications, the electrification of boilers would similarly eliminate the co-benefits with waste reuse, and studies that investigate electric boilers in these sectors should account for these co-benefits.

As shown in Fig. 4b, natural gas is the predominant fuel among industrial boilers in both the total quantity of boilers and installed capacity. While the number of natural gas boilers is high, many of them are low-capacity boilers with an average installed capacity of 30 MMBtu/hr.

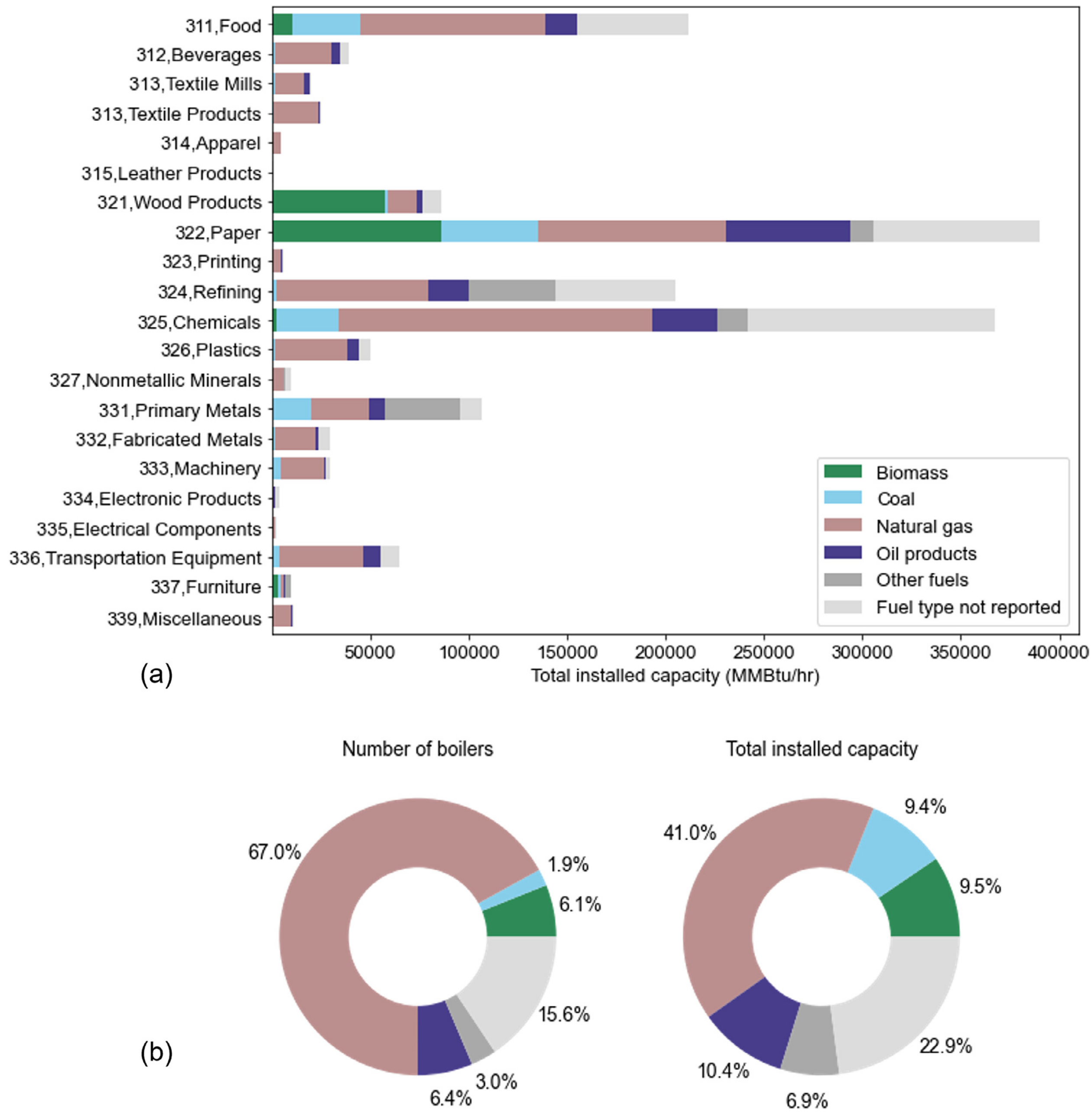

Fig. 4. (a) Estimated distributions of total boiler installed capacity by NAICS manufacturing subsectors and fuel type. “Other fuels” include still gas, waste gas, black liquor, among others listed in SI Table S1. Boilers from the EPA databases with a known installed capacity and subsector but without fuel type information are included above with “fuel type not reported.” **(b)** Percentages of number of boilers and total installed capacity by fuel type.

Conversely, the number of GHG-intensive coal boilers is relatively low, but the majority of coal boilers have capacities over 100 MMBtu/hr, and these high-capacity coal boilers are mostly used in the following subsectors: paper, food (wet corn milling, sugar, and oilseed industries), chemicals, and metals (iron and steel industry). Like coal boilers, fuel oil and diesel boilers are still used in small numbers in the paper and chemicals subsectors and could be a target for electrification due to their high emissions intensity and small number of relatively high installed capacities.

The location of industrial boilers is significant for evaluating the GHG emissions implications of boiler electrification, where renewable resource availability and emissions impacts vary greatly by region. Fig. 5 shows the estimated numbers of boiler units and total installed capacities per county.

Many conventional industrial boilers are concentrated in California, the Midwest, and the Northeast, but still are present in almost all counties across the United States. Counties in Texas, Louisiana, Indiana, Pennsylvania, and Washington have the highest total installed capacities. In counties with a large total installed capacity, there is typically a large portion of high-capacity boilers. For example, in Harris County, Texas, where there is a large presence of chemicals and refining facilities, the average installed capacity of industrial boilers is 150 MMBtu/hr. Similarly in Cowlitz County, Washington, where 28 of the 44 industrial boilers are in the paper subsector, the average installed boiler capacity is 360 MMBtu/hr. With large industrial boilers, replacement with electric boilers may require multiple electric boilers to meet capacity needs, leading to more extensive capital investments, despite the generally lower capital cost of electric boilers [48].

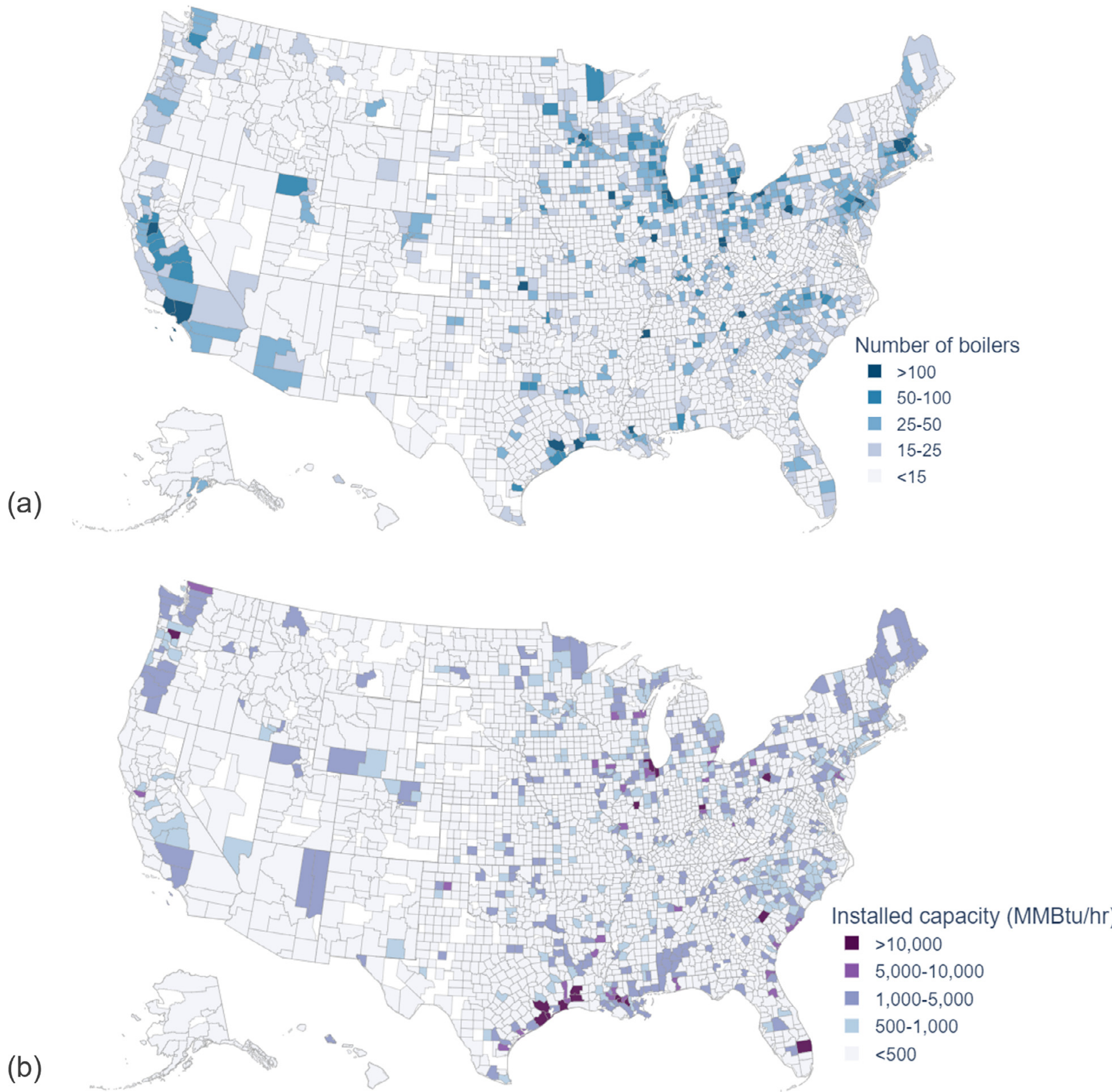

Fig. 5. U.S. county maps of **(a)** number of boilers and **(b)** total installed boiler capacity.

3.2. Electrification potential

While the characterization of industrial boilers by installed capacity, as shown in the previous section, illustrates the current stock of equipment, the electrification potential represents the energy associated with electrifying boilers. Specifically, the electrification potential depends on the boiler fuel consumption for steam demand in each subsector and county. Boiler fuel consumption, which differs from installed capacity due to differences in hours of operation and capacity utilization, is taken from the NREL manufacturing thermal energy use dataset that was used in our characterization of non-reported conventional boilers. Moreover, it should be noted that the fuel type categories in the NREL dataset and presented in this section vary slightly from those shown in Section 3.1 due to differences in fuel type classification between the Table 1 databases and MECS data (see Table S1 for more detail). Fig. 6 shows both estimated boiler fuel consumption by fuel type and the calculated electrification potential, totaled for each manufacturing subsector.

The petroleum refining, paper, chemicals, and food subsectors have the highest industrial boiler fuel use, but in refining, paper, and chemicals, a large percentage of boiler fuel consumption comes from fuels other than natural gas, coal, or oil products. In these subsectors and, to a smaller extent, in metals, food, and transportation equipment manufacturing, the use of byproduct fuels in conventional boilers is prevalent. Due to the complexity and added costs of replacing byproduct fuel use with electrification, the electrification potential is calculated for two cases: (1) all boiler fuel consumption is replaced with electrification, and (2) byproduct fuels are excluded from replacement, as marked by the light textured bars in Fig. 6. If all conventional boiler fuel use is replaced with electrification, the total electrification potential is 729,650 thousand MWh (2,490 TBtu), and if by byproduct fuels are excluded, the total electrification potential is 447,580 thousand MWh (1,527 TBtu). For reference, the total electricity demand in U.S. manufacturing in 2018 was 894,476 thousand MWh (3,052 TBtu) [49]. The electrification potential in both cases indicates a significant change to the energy mix of industrial manufacturing, nearly doubling the amount of electricity use

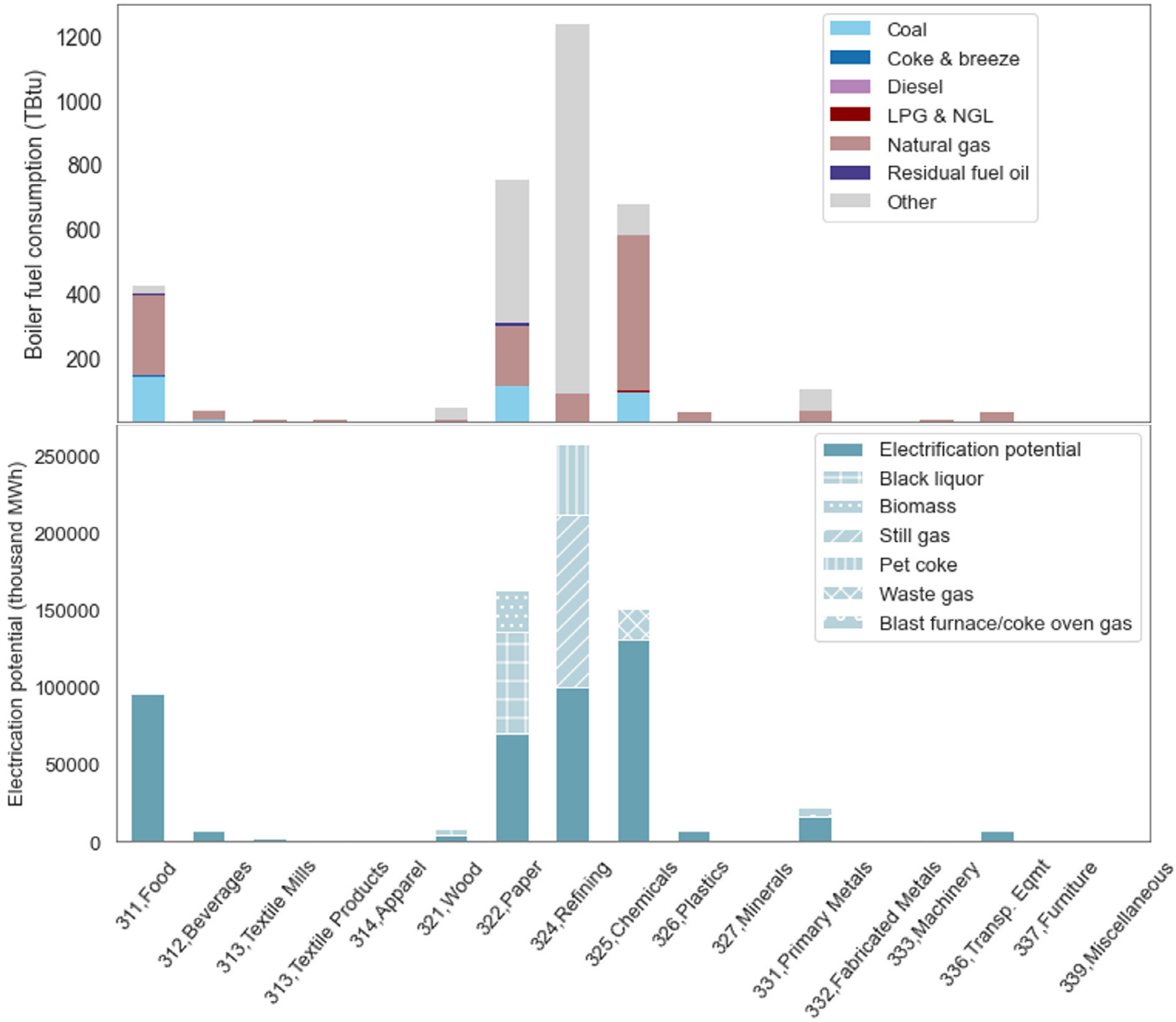

Fig. 6. Conventional boiler fuel consumption in 2014 by fuel type and NAICS manufacturing subsectors [8] (top) and electrification potential with the exclusion of specified byproduct fuels by NAICS manufacturing subsectors (bottom).

in manufacturing and increasing the amount of boiler electricity by two orders of magnitude [50].

3.3. Net changes in boiler fuel use and GHG emissions

To understand the net changes in overall fuel use associated with tapping the estimated electrification potential, we consider the resource mixes and power plant heat rates (fuel inputs per electric power output) of regional electric power grids in the U.S., according to eGRID 2019 data [51]. The fuels inputs necessary for the electricity required by electric boilers are compared to onsite fuel savings, or avoided fuels, from conventional boilers (Fig. 7). The fuel energy required to electrify boilers (4,275 TBtu) exceeds the fuel savings from replacing conventional boilers (3,337 TBtu) and leads to an increase in total national coal and natural gas consumption. This increase can be attributed to the low thermal efficiencies of coal and natural gas power plants and a sizable percentage of the electricity resource mix still met by these fossil fuels in counties with industrial boilers. Similarly, the net change in fuel use when byproduct fuels are excluded from electrification results in an additional fuel requirement of 619 TBtu and increased amounts of national coal and natural gas use. When byproduct fuels are excluded, there is an increased share of additional coal due to the location of facilities that use a large amount of byproduct fuels, especially in the Midwest, where there is a high percentage of coal in the electric grid mix.

The estimated net changes in fuel use shown above are based on the current U.S. electric grid mix, where the most recent eGRID data from 2019 details a combined U.S. grid mix of 38.4% natural gas, 23.3% coal, 19.6% nuclear, 17.6% renewables and <1% oil [51]. In the future, electricity generation from renewables is expected to increase as at least 20 U.S. states have passed either legislation or executive orders to achieve carbon-free electricity in the next 20 to 50 years [52]. To analyze the effects of electric grid makeups with a higher percentage of renewables, we evaluate two theoretical electric grid scenarios, based on the U.S. EIA Annual Energy Outlook (AEO) 2021 projections [53], and apply them to the current industrial boiler population. The first grid scenario is based on the AEO reference case in 2050, and the second grid scenario, on the low-cost renewables and low oil and gas supply cases in 2050 (see SI Section 4 for further details on electric grid scenarios and AEO projections). For each scenario, the electric grid mix by source is shown in Fig. 8a, and the percent change in electricity generation by source from current levels is shown in Fig. 8b. The high renewables scenario used in this analysis does not reflect the exact AEO 2050 grid mixes and does not reflect any specific policies.

Despite a considerable increase in renewables and a 40% decrease in coal-based electricity in the reference grid case, when applied to the current boiler population, the fuels required for electricity from boiler electrification still exceed the fuel savings from conventional boilers

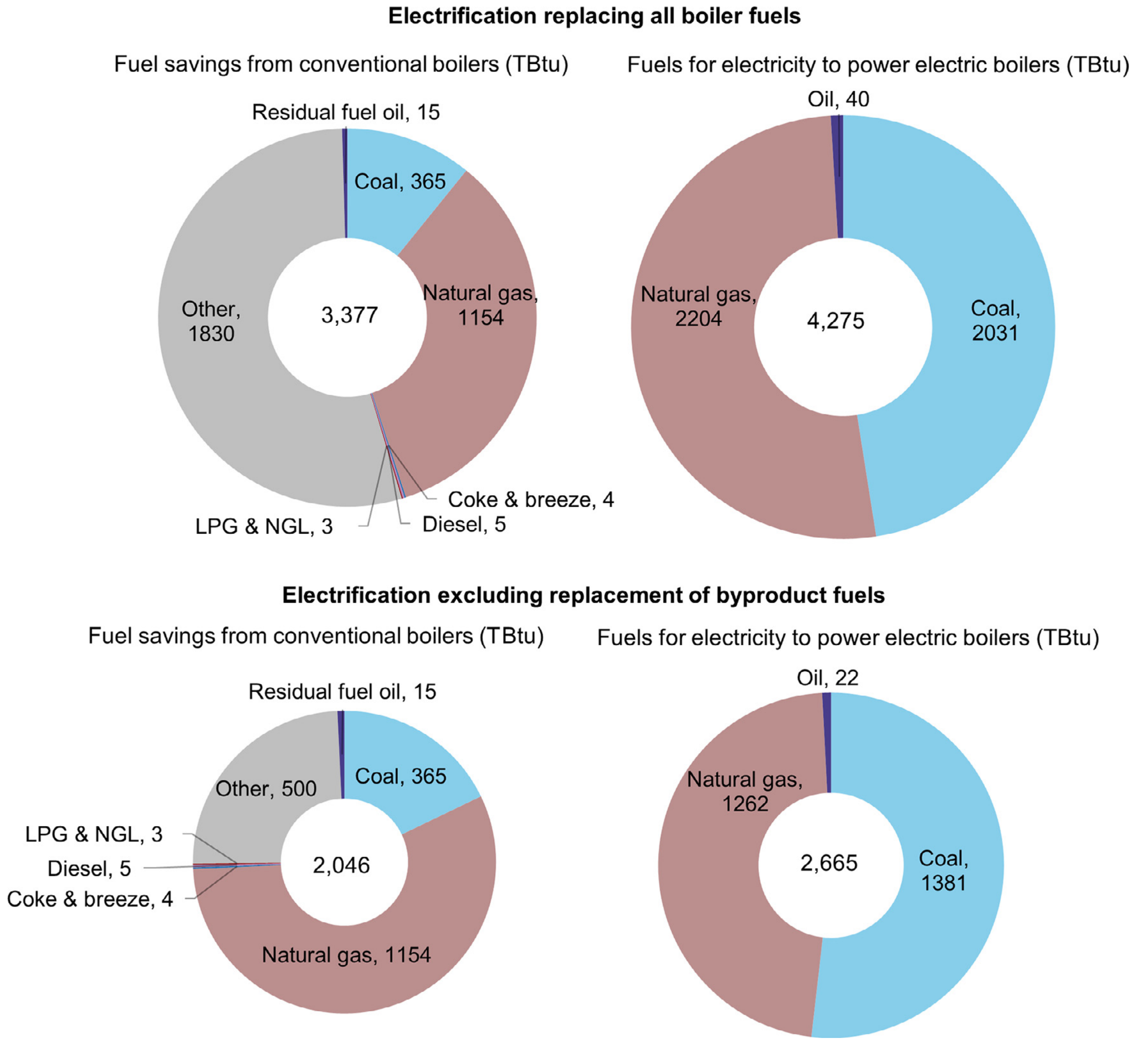

Fig. 7. Estimated changes in fuel use from boiler electrification if all boiler fuels are avoided (top) and if byproduct fuels are excluded from electrification (bottom). Based on eGRID 2019 electric power mix.

(Fig. 8b). Consequently, in this future reference case and under the current grid, there are more GHG emissions released at the nationwide level as a result of boiler electrification. GHG emissions would increase by 105 MMmtCO$_2$e under the current grid and 37 MMmtCO$_2$e under the future reference grid. The effects of increased fuel use and GHG emissions also occur under the current grid and future reference grid when boilers using byproduct fuels are excluded from electrification, although the additional required fuels and resulting GHG emissions are lower due to a portion of boiler energy demand being met by the existing byproduct fuels.

An overall reduction in fuel use and GHG emissions occurs only in the high renewables grid scenario, where electricity from coal and natural gas are reduced by 40% and 30%, respectively. In this case, GHG emissions savings are 19 MMmtCO2e, which amounts to 3% of onsite emissions from the current U.S. manufacturing sector (609 MMmtCO2e) [54]. Similarly, in the high renewables case, when byproduct fuels are excluded, there is an overall reduction in fuel use (8 TBtu) and GHG emissions (7 MMmtCO2e). The share of coal and natural gas in the electric grid mix contributes most to the disparate outcomes in GHG emissions, with the share of coal having a greater influence on GHG emissions due to its higher carbon intensity compared to natural gas.

While electrifying boilers would currently lead to an increase in GHG emissions overall under current grid assumptions, there are counties in the U.S. where the adoption of electric boilers would lead to reductions in GHG emissions today (Fig. 9). These counties are primarily in California, New York, and the Northeast, which represent the three subregions of the U.S. electric grid with the highest mix of clean electricity and lowest carbon intensity [55]. In some counties within these subregions, there are greater reductions in GHG emissions than others, which can be attributed to the level of boiler fuel use and fuel savings in the county. However, in most counties (2835 of the 3050 counties with boiler fuel use), boiler electrification would currently lead to an increase in GHG emissions. This analysis assumes average emissions factors for fuels based on regional electric power generation, but future work should consider marginal electricity generation and emissions rates and more detailed grid modeling.

In the future reference case grid, where there is a considerable decrease in electricity from coal and slight increase in electricity from natural gas, there are additional counties in the Northwest and Southeast that show reductions in GHG emissions (516 counties with GHG emissions reductions in total when electrification replaces all boiler fuels). For instance, in several counties in the Northwest and West, which rely less on natural gas and more on coal for electricity, the net GHG emissions become negative, indicating a reduction in emissions. With a reduced mix of both coal and natural gas in the high renewables case grid, more counties throughout the country are shown have GHG emissions reductions (1103 counties in total when electrification replaces all boiler fuels).

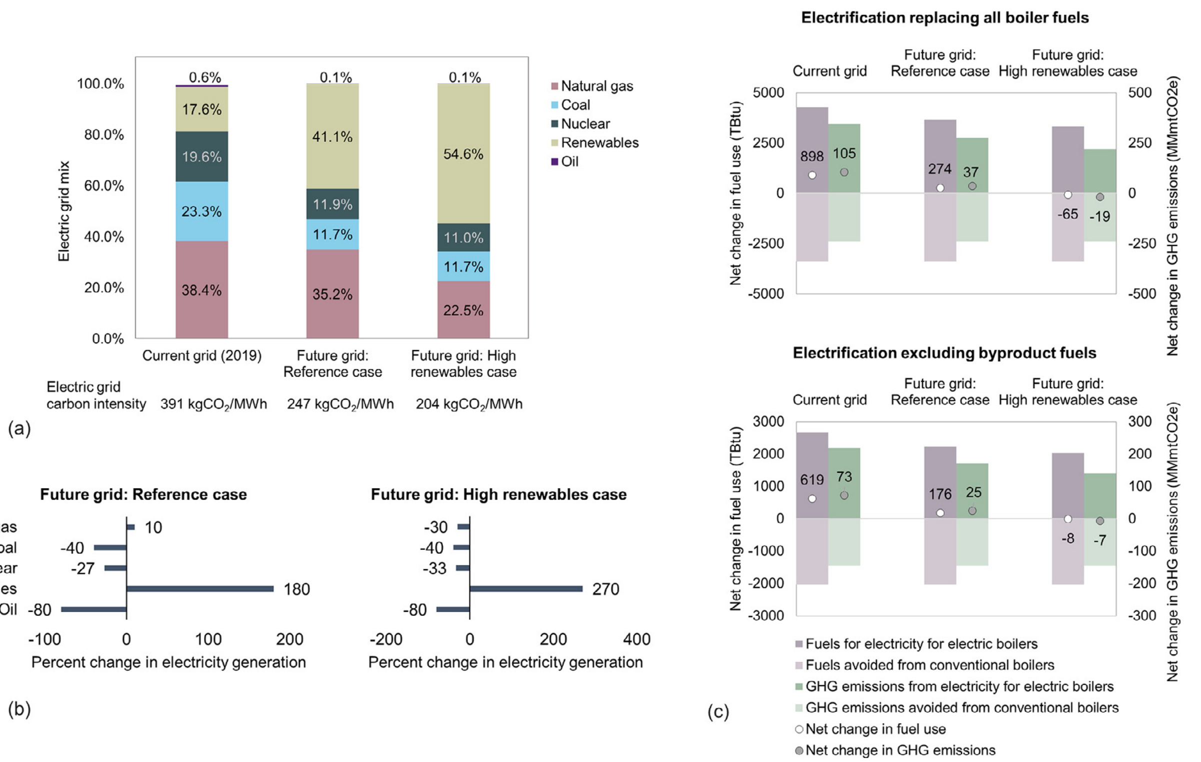

Fig. 8. **(a)** Electric grid mix (percentages) and carbon intensity ($kgCO_2/MWh$) for the current grid and future cases. **(b)** Percent change in electricity generation of two future grid scenarios: reference case and high renewables case (combination of low-cost renewables case and low oil and gas supply case). **(c)** Estimated net changes in fuel use and GHG emissions from electrifying the current boiler population under the current electric grid, reference case grid, and high renewables case grid.

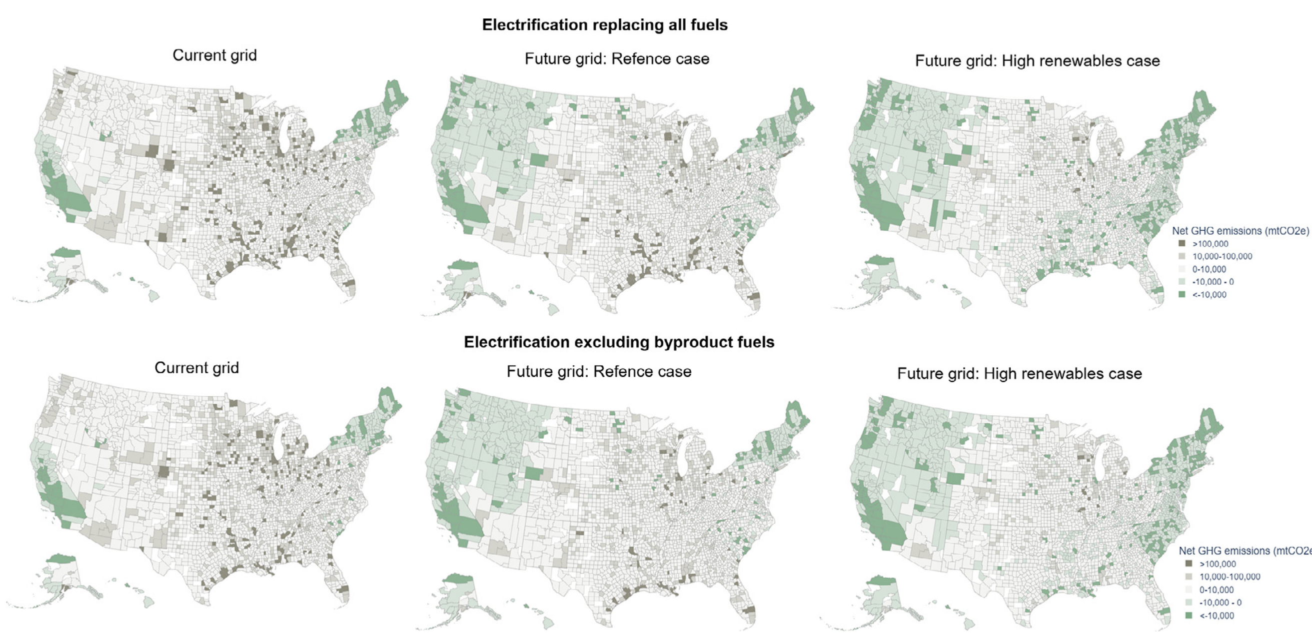

Fig. 9. U.S. county maps of net changes in GHG emissions from boiler electrification under the current electric grid, reference case grid, and high renewables case grid.

In this regard, our study is consistent with past work [19–22] but expands the focus in the U.S., considering the boiler population per county and the effects of the fuel mix in the grid on emissions. In particular, this work emphasizes the need for reducing emissions in the life cycle of electricity generation, such as upstream natural gas leakage [56], the adoption of clean generation technologies, including carbon capture and sequestration (CCS) in coal and natural gas power plants, and increasing the share of renewable and nuclear electricity generation. Furthermore, energy efficiency measures that reduce steam demand could make electrification more favorable and improve the overall investment economics considerably [57–59]. A facility-level economic analysis could incorporate the effects of efficiency gains and other non-energy benefits and expand on previous work that has demonstrated methods for calculating economic parity for electric boilers [60].

4. Conclusions

4.1. Summary of contributions

The electrification potential of industrial boilers and the GHG emissions impact of their electrification are affected significantly by the current population of boilers, county-level boiler fuel consumption, and the fuel mix of the electric grid. In this study, we developed an up-to-date industrial boiler dataset that characterizes boilers by county, manufacturing subsector, installed capacity, and fuel type. This comprehensive dataset integrates multiple national facility-level emissions databases, serves as an updated resource for the U.S. industrial boiler population, which prior to this study has not been updated in nearly twenty years, and provides characteristics of conventional boilers traced to individual units. In the second major contribution of this study, we quantified the county-level electrification potential and net changes in fuel use and GHG emissions for industrial boilers under multiple assumed national grid mixes. For these analyses, we calculated the steam demand of boilers based on conventional boiler fuel consumption and the required electrical energy for electric boilers, accounted for the use of byproduct fuels in the potential to electrify boilers, and considered the full fuel cycle GHG emissions.

Our results show that the largest electrification potential of industrial boilers is in the chemicals, refining, and paper subsectors, when electrifying all conventional boilers, and the chemicals, refining, and food subsectors, when excluding boilers using byproduct fuels from potential replacement with electrification. We find that electrifying boilers leads to an overall increase in national fuel use and GHG emissions based on the current national grid mix, but that in some U.S. counties where the regional electric grid has a low carbon intensity, boiler electrification would lead to a reduction in GHG emissions today. In the future reference grid scenario, where coal is reduced from the electric grid mix and natural gas is increased, overall fuel use and GHG emissions would still increase. In the high renewables grid scenario, where both the percentage of coal and natural gas in the electric grid mix decrease significantly, overall GHG emissions would be reduced.

This study uniquely contributes a more granular understanding of boiler electrification potential in the U.S. With consideration of county-level fuel consumption of boilers and the regional electric grid resource mixes, the GHG emissions impacts from changes in power generation can be shown by county and subsector. This detail could be used to inform policy makers who are interested in policy development that considers regional factors. Our scenario analysis demonstrated the sensitivity of results to coal and natural gas use in the electric grid and, more broadly, the importance of accelerating grid decarbonization for industrial electrification technologies to result in net GHG emissions reductions.

4.2. Future work

This research on industrial boiler technology, energy, and emissions data addressed knowledge gaps about the climate change mitigation potential of electric boilers but also revealed several areas for future research. First, future research could incorporate data from other non-standardized sources. As an example, data science methods could be employed to extract boiler unit data from state air permits. Using these data would address the limitations in national-level equipment and emissions databases. Furthermore, the inclusion of additional unit characteristics, such as year of installation, from these data sources would better predict long-term decarbonization potential. Second, future research could address the significant electricity load additions from industrial electrification and integrate grid modeling that considers both electrification load and grid generation mixes in more temporal detail (e.g., hourly) and quantifies the marginal emissions to meet electric boiler loads. Third, future work could consider heat pumps as an alternative electrified heating technology because they increase efficiency and could be enabled by the results of this study to assess the optimal deployment decisions for electric boilers and heat pumps. Finally, an economic analysis could investigate facility-level costs associated with the electrification of boilers, such as investment costs, operation and maintenance costs (e.g., regional fuel and electricity costs), and avoided mitigation costs.

Moreover, since our analysis showed that industrial boiler electrification may not lead to fuel and GHG emissions savings uniformly throughout the U.S., manufacturing facility decision makers and policy makers could consider the following points. First, for facilities and locations where fuel and emissions savings are not immediately apparent, reducing steam demand in plant processes through efficiency measures could reduce the needed replacement capacities and improve economic feasibility. Second, possible economic co-benefits of boiler electrification (e.g., reduced pollution abatement costs, smaller equipment footprints) could be accounted for, which could also improve the economics of electric boiler investments. Standardized best practice costing guidance could be provided to facility decision makers to capture these important co-benefits in investment analyses. Third, for boilers that are likely to continue using byproducts or residues as fuels, CCS could be implemented instead of stranding the byproducts, which may be combusted in another way. Industrial boiler electrification is one potential solution for a transition from fossil fuel-based technologies but is highly dependent on a decarbonized electric grid and further policy evaluation.

Author contributions

CS: Conceptualization; Data curation; Formal analysis; Funding acquisition; Investigation; Methodology; Project administration; Coding; Visualization; Writing - original draft; Writing - review & editing. **JZ**: Conceptualization; Data curation; Formal analysis; Investigation; Methodology; Project administration; Coding; Writing - original draft; Writing - review & editing. **CM**: Conceptualization; Methodology; Coding; Writing - review & editing. **JD**: Conceptualization; Methodology; Supervision; Writing - review & editing. **EM**: Conceptualization; Methodology; Supervision; Writing - review & editing.

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.

Acknowledgments

CS was supported by the National Science Foundation GRFP grant DGE-1842165.

This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Office of Strategic Programs. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

Data and code availability

The industrial boiler dataset and all code is available at the following GitHub repository: https://github.com/carriescho/Electrification-of-Boilers. The dataset is an estimated inventory of industrial boilers in the U.S. with unit-level detail of boiler capacity (MMBtu/hr), boiler fuel type, county (FIPS code), and industrial subsector (three-digit NAICS code).

Appendix: supporting information

Document available for download.

Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.adapen.2022.100089.

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