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Energy intensity, life-cycle greenhouse gas emissions, and economic assessment of liquid biofuel pipelines

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HIGHLIGHTS

- Energy use, GHG emissions, costs, and profits are modeled for biofuel pipelines.
- Design diameters are found that maximize NPV of ethanol and biodiesel pipelines.
- State-specific pipeline breakeven tariffs and GHG emission factors are presented.
- Pipeline performance is compared to alternative modes: trucks, trains, and barges.
- Pipeline competitiveness depends on location, flow rate, and economic conditions.

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ABSTRACT

Petroleum fuels are predominantly transported domestically by pipelines, whereas biofuels are almost exclusively transported by rail, barge, and truck. As biofuel production increases, new pipelines may become economically attractive. Location-specific variables impacting pipeline viability include construction costs, availability and costs of alternative transportation modes, electricity prices and emissions (if priced), throughput, and subsurface temperature.

When transporting alcohol or diesel-like fuels, pipelines have a lower direct energy intensity than rail, barge, and trucks if fluid velocity is under 1 m/s for 4-inch diameter pipelines and 2 m/s for 8-inch or larger pipelines. Across multiple hypothetical state-specific scenarios, profit-maximizing design velocities range from 1.2 to 1.9 m/s. In costs and GHG emissions, optimized pipelines outperform trucks in each state and rail and barge in most states, if projected throughput exceeds four billion liters/year. If emissions are priced, optimum design diameters typically increase to reduce pumping energy demands, increasing the cost-effectiveness of pipeline projects.

1. Introduction

1.1. Biofuel policy goals and distribution challenges

Major goals motivating pro-biofuel policies in the United States stem from perceived supply chain benefits over petroleum, and include reducing life-cycle greenhouse gas emissions from the transportation sector, improving trade balance, diversifying energy supplies, reducing energy costs to consumers, and stimulating rural development by increasing demand for agricultural products (Rajagopal and Zilberman, 2007).The Energy Independence and Security Act of 2007 created the national goal to consume 36 billion gallons per year (bgy), i.e., 136 billion liters per year (bly), of biofuels by 2022 (Rahall [D-WV3], 2007). In 2011, the United States produced 14 billion gallons (49 billion L) of ethanol and only 970 million gallons (3.7 billion L) of biodiesel (US EIA, 2013a).

Due to the rural locations of many biorefineries, biofuels must be transported long distances to reach existing fuel blending infrastructure. Additionally, gasoline blends around the Midwest have become saturated at the E10 (gasoline containing 10% ethanol v/v) blend wall over the last decade. Under this constraint, Midwestern states have been increasing the quantity and distance of interstate ethanol shipments, and the average producer-to-consumer distance has exceeded 1100 km since 2004 (Strogen et al., 2012); this average distance is expected to increase by 2020 under most cellulosic ethanol scale-up scenarios considered by Scown et al. (2012), even if gasoline can be blended with up to 20% ethanol by volume. As the typical producer-to-consumer distance is unlikely to decrease over the next decade, transporting biofuels through pipelines is likely to be economically attractive under certain conditions.

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In contrast to petroleum fuels and natural gas, which are distributed domestically by extensive pipeline networks (e.g., 283000 km of hazardous liquid pipelines), only 26 km of ethanol pipelines were registered with the Department of Transportation in 2011 (US DOT PHMSA, 2012). However, it is technically feasible and not uncommon to retrofit existing pipelines to handle new products (e.g., converting a gas line to a liquid fuel line), or to reverse the direction of flow in pipelines. Ethanol is already distributed occasionally through existing petroleum pipelines, though such conversion typically requires special precautions to ensure ethanol does not damage pipeline materials or degrade fuel quality (e.g., cleaning interior surfaces, upgrading materials, minimizing opportunities for fuel exposure to oxygen and water, and dosing fuel with corrosion inhibitors). Currently, there are few opportunities to utilize existing pipelines for biofuels, as the locations where most US biofuels are produced makes it "impossible to leverage the existing network" of petroleum infrastructure (US DOE, 2010). Even under optimistic scenarios with drop-in biofuel production increasing by 3 bly starting in 2015, new product pipelines would be required to transport biofuels from production facilities to the existing petroleum distribution system (NRC, 2013).

1.2. Economic and environmental aspects of pipelines

Current modes for transporting biofuels domestically (rail, truck, and barge) rely almost exclusively on petroleum-derived diesel or residual oil, and approximately half of petroleum products consumed in the United States are refined from imported crude oil (US EIA, 2013a). In contrast, liquid pipelines are predominantly powered by electricity, only 1% of which is generated from petroleum, as electricity is primarily generated from domestic non-petroleum resources (i.e., 42% coal, 24% natural gas, 19% nuclear, and 13% renewables in 2011 (US EIA, 2013a)). Therefore, shipping fuels by pipelines would reduce total supply chain demand for petroleum, and possibly total energy use and emissions. The relative performance superiority of one mode over another often changes under real world conditions, largely because energy intensity varies within each mode as a result of equipment technology and age, scale, geography, infrastructure quality and circuity, elevation change, congestion, operator behavior, and many other factors. Additionally, the GHG intensity of each mode depends on energy intensity of operations as well as the GHG intensity of the fuel source and supporting equipment and infrastructure.

The carbon content of petroleum fuels is a relatively consistent property, resulting in tailpipe emissions of 73–75 g CO_2-e/MJ for gasoline, diesel, and jet fuel (US DOE ANL, 2010), though tailpipe emissions typically only make up 81–85% of total fuel-cycle emissions (US DOE ANL, 2010; Dray et al., 2012). In contrast, state-average emissions per unit of generated electricity range from 1 gram CO_2-e per MJ of electricity (g CO_2-e/MJ_e) in Vermont (74% nuclear, 26% renewable) and 15 g CO_2-e/MJ_e in Idaho (80% hydro) up to 268 g CO_2-e/MJ_e in Wyoming (91% coal) and 314 g CO_2-e/MJ_e in Washington, DC (100% oil) (US EPA, 2012). As a result, if a pipeline is able to transport fluid at the identical energy intensity as a petroleum-powered vehicle, the resulting (operations only) emissions could be much less or much greater than vehicular transport.

2. Methods

2.1. Goal and scope

The economic and environmental aspects of transporting various liquid fuels by pipelines are estimated for comparison to alternative modes. A model was developed using a life-cycle framework to differentiate these impacts across various fuels and locations under plausible economic assumptions. As pipeline operating costs and emissions are tied to energy consumption, energy intensity values for pumping five different fuels are first estimated and presented for a range of pipeline design and operating configurations at the low and high temperature extremes (and therefore viscosity extremes) found in the contiguous United States.

Hypothetical pipelines are then designed, and life-cycle costs and GHG emissions estimated, for several volumetric flow rates, liquid fuels, and states. The boundary of analysis for pipelines includes initial construction, operations, and maintenance; alternative modes are assumed to already have infrastructure in place, so costs and emissions are modeled only for operations and maintenance activities. Results highlight the variability in conclusions that would be found when consideration is given to regional heterogeneity, specific fluid properties, and economies of scale in construction and operation.

2.2. Simplifying assumptions

In order to model the economic, energy, and environmental performance of a pipeline system, details must be understood about the fluid, pipeline dimensions, ambient conditions surrounding the pipeline, and the financial and resource inputs to constructing, operating, and maintaining a pipeline. For the purposes of developing a model with results that are easy to interpret and apply to specific case studies, the following simplifying assumptions and study limitations have been set.

1. The functional unit of service for evaluating freight transportation modes is the (metric) tonne-kilometer, t-km, (though transportation managers also value speed, reliability, and other considerations). Unlike pipelines, freight transport vehicles must return to their supplier; empty backhaul distance is assumed to be equivalent to delivery distance.
2. Transportation infrastructure circuity factors are ignored. That is, in comparing costs and emissions from transporting fuel 1000 km by pipeline to other modes, results are presented as if fuel would be transported 1000 km by alternative modes (though the actual distance along the best available route may be 800 or 1400 km, for example).
3. Fuel supply, fuel demand, and demand for transportation services are all assumed to be inelastic. That is, if pipelines perform better than other modes (e.g., at lower costs), there is no assumed change to the quantity, distance, or destination of fuels transported.
4. Although crude and product pipelines only operated at 73% and 57% of their design capacity in 1978 (Hooker, 1981), new biofuel pipelines are assumed to have a utilization rate (operations factor) of 90%, consistent with Pootakham and Kumar (2010). Therefore, the annual average flow rate is 90% of the flow rate found during actual operations. In reality, operation will not be as simple as "on/off" due to variations in fuel supply, fuel demand, and electricity prices. For example, operators may increase throughput during off-peak hours. As marginal electricity GHG emission factors may be 30% greater at night than at mid-day (Siler-Evans et al., 2012), such decisions may result in lower costs but greater energy and emissions intensity.
5. All fuels evaluated are assumed to be pure. In reality, fuels shipped through pipelines may contain small amounts of water, contaminants, or additives such as denaturants, drag reducing agents, corrosion inhibitors, biocides, among others. Costs and GHG emissions implications from such additives are ignored.
6. Insulation and heaters for pipelines were not considered in this analysis.

2.3. Pipeline system operations

2.3.1. Liquid fuel properties

The five liquid fuels selected for this study, in order of increasing mass density, are: ethanol (today's dominant US biofuel), methanol (an alternative fuel that can be produced from biomass or natural gas), butanol (an alcohol with greater energy density and "drop-in" capability than ethanol), soy methyl ester (SME, aka biodiesel, today's dominant US diesel-displacing biofuel), and diesel #2 (a hypothetical "drop-in" fuel, indistinguishable from petroleum diesel). The lower heating values of these fuels are assumed to be 26.952, 20.094, 34.366, 42.791, and 37.528 MJ/kg, respectively (US DOE ANL, 2010).

For trains, trucks, and barges that transport liquid commodities, fluid properties that impact energy intensity are primarily limited to material density and any properties that require special vehicle configuration for safe material handling. In contrast, the fluid's mass density, ρ, and also dynamic viscosity, μ, influence the power requirements of pipeline pump stations, and both properties vary with temperature. Table S2 in the Supplementary data (SD) provides key physical parameters and their relationships to temperature for each fuel.

2.3.2. Pumping energy intensity

Pumping energy requirements are determined by head loss, which results from viscous resistance (friction) against the pipe's interior surface. The mass-based pumping energy intensity (kJ_e/t-km) required to overcome friction losses are estimated using an approximation of the Colebrook equation, in which the Darcy friction factor, λ, is estimated using the method of Vatankhah and Kouchakzadeh (2008), and the main input parameters include fluid kinematic viscosity, ν (i.e., μ/ρ); fluid velocity, u; pipe inner diameter, ID; and pipe interior surface roughness, ε (commonly assumed to be 45 μm for steel pipes). This method was found to have a maximum error of less than 0.15% compared with the implicit Colebrook equation for a roughness-to-diameter ratio (ε/ID) range of 10^{-6} to 0.1 and Reynolds number range of 10^4–10^8 (Brkić, 2011); the operating conditions considered in the current analysis are well within these modeling limits. In this analysis, minor losses from pipe bends and fittings are ignored. Elevation changes are also ignored, though elevation gain would demand greater energy intensity for all modes considered.

Energy intensity is estimated for pipelines with an ID of 2–24 inches (5.1–61 cm), and mean fluid velocity of 1–3 m/s, for the five liquid biofuels under low and high soil temperature conditions. In order to model project life-cycle scenarios, a relationship between diameter and pipe thickness is needed. Pipe wall thickness (t) prescribed for ANSI Schedule 40 pipes is presented in Table S7, and the relationship between outer diameter (OD) and thickness is approximated with the equation (with units in inches), $t = 0.11 * \mathrm{OD}^{0.54}$, so that ID can be estimated with the equation, $\mathrm{ID} = \mathrm{OD} - 2t$. Mean fluid velocity is calculated by dividing volumetric flow rate, Q, by the interior cross-sectional area, S_i (where $S_i = 0.25 * \pi * \mathrm{ID}^2$).

Although variations in head loss due to temperature-driven viscosity changes were considered unimportant and therefore neglected in modeling total energy use in US petroleum product pipelines (Hooker, 1981), temperature is included in the current study to more comprehensively account for differences between states that impact costs and energy use. The fluid temperature inside the pipeline is assumed to be 1.67 K greater than soil temperature, consistent with the isothermal approximation of Modisette (2002). Motors and pumps are assumed to be 86% and 93% efficient, respectively (Hooker, 1981), for a total conversion efficiency of 80% from drawn grid electricity into power exerted on the fluid.

2.4. Pipeline system construction and maintenance

2.4.1. Pipeline construction and maintenance costs

A common method to normalize pipeline construction costs of different diameters is to report costs per unit diameter and length (e.g., per "inch-mile"), though the location and length of pipelines also impact unit costs. Costs vary considerably across different landscapes, with urban areas and rocky terrain requiring significant expenditures (van der Zwaan et al., 2011), and costs also vary by region due to labor, regulatory, and other conditions. Construction also benefits substantially from economies of scale, as 80-km pipelines can cost 1.7 times that of 1300-km pipelines per km (Rui et al., 2011).

Pipeline construction costs by region are estimated for 2008 using the regression model for onshore pipelines developed by Rui et al. (2011), assuming costs for biofuel pipelines are comparable to oil and gas pipelines. Since average pipeline construction costs did not consistently increase from 2008 to 2009 (Smith, 2012), modeled cost formulas (shown in section SD-3) are assumed to be applicable to the model year 2009. Rui et al.'s regression model is expected to more accurately estimate costs for long-distance pipelines than could be estimated with the limited data on biofuel pipelines that have already been constructed. Additionally, while Rui et al.'s model was developed with data limited to 8-inch and larger pipelines, costs estimated with this model for smaller diameter pipelines were found to be slightly higher than those previously estimated for 4–8 inches carbon steel pipelines (and much greater than plastic pipelines) as presented in Table S6; therefore, costs are considered overestimates.

The construction period is assumed to last two years. Once operating, annual pipeline maintenance costs are assumed equivalent to 3% of capital costs, consistent with Pootakham and Kumar (2010). The expected lifespan is 20 years, though a 40-year lifespan was assumed for a hypothetical ethanol pipeline evaluated by US DOE (2010) (and more than 30% of onshore liquid pipelines were constructed before 1960 (US DOT PHMSA, 2012)).

2.4.2. Pump station construction and maintenance costs

Pump stations are typically found every 80 km (50 miles) or so, and contain breakout and storage tanks, pumps, shut-off valves, and leak detection equipment (Strogen, 2012). Independent of the number and size of pumping stations, a fixed installed cost of \$1900/hp (\$2548/kW) was assumed for the model year 2009 (adjusting a previous approximation of \$1500/hp (Menon, 2004) with the US producer price index for "Industrial pumps, except hydraulic fluid power pump", and coinciding with the average actual installed cost per horsepower for compressor stations (Smith, 2012)). Annual maintenance costs are approximated as 3% of capital costs (Pootakham and Kumar, 2010).

2.4.3. Construction and maintenance emissions estimation

The method for estimating the embodied GHG emissions in constructing pipelines was adapted from (Strogen, 2012), in which line pipe, pumps, and right-of-way costs were translated into GHG emissions using tables from the US Economic Input–Output Life-cycle Assessment (EIO-LCA) tool (CMU GDI, 2010); details can be found in section SD-3. Embodied emissions were only estimated for material and energy intensive processes, consistent with (Strogen and Horvath, 2013), such that labor, taxes, and other "administrative" economic inputs are ignored. Given these assumptions, construction GHG emissions (t CO_2-e/km) can be estimated as a function of OD (inches), with the formula, $0.4254 * \mathrm{OD}^2 + 3.3814 * \mathrm{OD} + 8.0895$. A review of alternative methods to estimate steel mass and construction GHG emissions can be found in section SD-3. Annual maintenance emissions are approximated as 3% of initial construction emissions.

2.5. Regional construction and electricity characteristics

In order to highlight the importance of location in comparing the relative costs of pipelines to other modes of transportation, illustrative but reasonable states were selected to represent a wide variety of construction costs, soil temperatures (in winter at the assumed pipeline depth of 2 m), as well as industrial electricity prices and GHG intensity of electricity generation, as can be seen in the rankings presented in the right-most columns of Table 1.

As the scenarios present possible near-term biofuel pipeline projects, these emission factors reflect the hypothetical case that states proportionally expand current generation technologies to satisfy pumping energy demand and/or GHG emissions reporting protocol entails the use of local production emission factors. Although not a major biofuel producer or consumer, Vermont was selected to showcase potential results if pipelines are operated with extremely low-carbon electricity. (If marginal regional emission factors were employed, such as those estimated for 2007 by Siler-Evans et al. (2012), differences in emission factors between states would shrink to 70% or less; this approach would yield emission factors 192 times the modeled emission factor in Table 1 for Vermont, 2.92 times for New Jersey, 1.83 for California, 1.16 for Illinois, 1.06 for Florida, and 0.78 for Indiana.)

2.6. Alternative mode characteristics

A non-exhaustive literature review found a range of energy intensity values for transporting liquid fuels by different modes in or after the year 2000, which are listed in addition to the recommended characteristic value for long-distance transport in Table 2. Table 2 also shows the characteristic life-cycle GHG emission factors for each mode, after accounting for infrastructure and maintenance. Just as the energy and emissions intensity by mode varies under different conditions, operating and maintenance costs also vary significantly. Table 2 presents the high, low, and characteristic costs per t-km of the three major modes for comparison with pipelines. The ratio of modeled characteristic costs between modes is relatively consistent with ratio of average costs for all freight shipped by truck, rail, and barge during the years 2000–2004, i.e., 9.3:1.6:1.2 ¢/t-km (US DOT BTS, 2013).

2.7. Scenario analysis for hypothetical pipeline projects

In order to determine if pipelines are competitive with alternative modes, hypothetical conditions for pipeline construction and operation are considered. Although energy intensity is estimated for all fuels, modeling of economics and GHG emissions is limited to pipelines transporting ethanol and soy methyl ester (biodiesel), as these are the most common biofuels in the United States. For both fuels, annual mass throughput rates of 0.30, 3.0, and 9.0 million tonnes per year (MMtpy) are considered; at 293.15 K (68° F), these rates correspond to 0.380 bly (0.100 bgy), 3.80 bly (1.00 bgy), and 11.4 bly (3.01 bgy) of ethanol, and 0.339 bly (0.0896 bgy), 3.39 bly (0.896 bgy), and 10.2 bly (2.69 bgy) of SME. For each scenario, construction costs per km are estimated using 400 km as the length input to Rui et al.'s model (i.e., ignoring economies of scale beyond this length). For the 0.3 MMtpy scenarios, pipelines are arbitrarily assumed to be gathering lines that compete with trucks (e.g., due to lack of access to railroads or waterways, and/or because the higher fixed (loading/unloading) costs of rail and barge enable trucks to be cost-competitive up to this distance). For greater flow rates and longer distances, pipelines are assumed to compete with barge or rail, and rail is regarded as the most likely competitor.

Pipeline diameters were optimized to produce maximum net present value (NPV) of earnings before taxes, depreciation,

Table 1
Construction cost region, subsurface ground temperature, and electricity properties for select states in 2009 (properties of additional states can be found in Table S1).

State	Region[a]	Subsurface Temp. (K)[b]		Electricity price[c]	GHG emission factor	Electricity generation resource mix[d]				T&D efficiency (%)[e]	Price rank (of 51)	GHG rank (of 51)
		Min	Max	¢/MJ_e	g CO_2-e/ MJ_e[f]	Coal (%)	Gas (%)	Nuclear (%)	Renewables (%)			
California	Western	280	291	2.80	79	1	55	16	26	89.0	8	45
Florida	Southeast	292	299	2.59	164	25	54	13	2	92.2	12	25
Illinois	Midwest	291	280	1.90	141	6	2	49	2	95.8	20	35
Indiana	Midwest	280	289.5	1.61	274	93	3	0	2	93.9	33	5
New Jersey	Northeast	279	289	3.28	75	8	33	55	1	92.8	7	46
Vermont	Northeast	275	283.5	2.56	1	0	0	74	26	97.0	13	51

[a] Pipeline construction cost regions are characterized by Rui et al. (2011).
[b] Maximum and minimum temperatures at 2 m below ground are estimated for the period 2010–2012 by visually interpreting maps from US DOC NOAA (2012).
[c] State-specific industrial electricity prices are obtained for 2009 from US EIA (2013b).
[d] State-specific generation resource mix values were obtained from EPA's eGRID 2012 version 1.0 data files US EPA (2012), with percentage values presented for coal (STCLPR), gas (STGSPR), nuclear (STNCPR), and renewables (sum of STHYPR, STBMPR, STWIPR, STSOPR, and STGTPR). Numbers may not add to 100 due to exclusion of oil (STOLPR) and unknown/purchased fuel (STOPPR).
[e] 2009 Electricity transmission and distribution (T&D) loss rates by state are estimated with data from US EIA (2013b), by dividing "Estimated Losses" by the result of "Total Disposition minus Direct Use".
[f] State-specific GHG emission factors are estimated by dividing state annual CO_2-e emissions in tons (STCO2EQA) by state annual net generation in MWh (STNGENAN), as presented in EPA's eGRID 2012 version 1.0 data files (US EPA, 2012), converted to SI units (1 kWh = 3.6 MJ), and divided by the T&D efficiency, to yield an emissions factor (g CO_2-e /MJ_e) at the point of use.

Table 2
Cost, energy, and GHG intensities of alternative modes of transporting liquid fuels.

	Units	Truck (Tanker)	Rail (Unit Train)	Barge (Inland Tow)
Operating Energy Intensity[a]				
Low	kJ/t-km	1100	220	200
Characteristic	kJ/t-km	1200	270	320
High	kJ/t-km	2000	380	510
Life-cycle GHG Intensity of transportation service[b]				
Low	g CO_2-e /t-km	125[c]	20[c]	19
Characteristic	g CO_2-e /t-km	138	25	31
High	g CO_2-e /t-km	227	35	49
Freight Transportation Cost				
Low	$/t-km	$0.07[d]	$0.009[e]	$0.007[f]
Characteristic	$/t-km	$0.10	$0.02	$0.015
High	$/t-km	$0.15[g]	$0.05[g]	$0.09[f]

[a] Characteristic energy intensity values are obtained from Strogen et al. (2012), and the range of values are discussed by Strogen (2012).
[b] Life-cycle emissions (including fuel production, infrastructure and freight transportation vehicle maintenance) are normalized to the characteristic fuel use intensity of each vehicle as reported by Strogen and Horvath (2013).
[c] Lower life-cycle emission factors were reported for 2009 in the EU: 47 g CO_2-e/t-km for heavy trucks and 18 g CO_2-e/t-km for freight trains (Dray et al., 2012).
[d] The cost of trucking liquid biofuels has been assumed to cost as low as $0.04/t-km ($0.07/t-km if including loading/unloading costs for a 400 km trip) Pootakham and Kumar (2010).
[e] The marginal cost of transporting ethanol was reported as $0.009–$0.021/t-km in 2008 USD (Hughes, 2011), and average rates reported by the Association of American Railroads range from $0.02/t-km for coal and grains up to 0.04/t-km for chemicals, pulp and paper in 2011 USD (AAR, 2012).
[f] The highly variable marginal costs of barge transportation, including waterway maintenance (not fully incorporated into private costs), is discussed by Strogen (2012).
[g] Morrow et al. model trucking costs at $0.15/t-km and rail costs at $0.05/t-km (Morrow et al., 2006).

and amortization by discounting future cash flows (treated as annuities) in the equation, $NPV = (R_t - C_e - C_m)/r * [(1+r)^{-n_c} - (1+r)^{(-n_c + n_o)}] - C_c$, which accounts for annual tariff revenues (R_t); annual electricity costs (C_e); annual maintenance costs (C_m); the construction period, in years, between initial investment and commencement of operations (n_c); the operating lifespan in years (n_o); the weighted average cost of capital, or WACC, (r); and the initial cost of construction, which is assumed to be paid in full at time "zero" (C_C). Although pipelines are typically produced at standard diameters, this analysis highlights how design decisions would change under different conditions, and holds fixed the quantity of fuel transported. Pipelines are considered viable if the breakeven tariff is equivalent to the characteristic price of the competing mode(s), and are considered to save GHG emissions if emissions are lower than the characteristic emissions for the alternative mode(s) as reported in Table 2.

Master limited partnerships (MLP) typically have a debt/equity ratio of 1.5, and ethanol pipelines are expected to require a 15% return on equity (US DOE, 2010). Assuming an upper bound on the cost of debt of 6.7%, a WACC of 10% is assumed. A discount rate of 10% has also been used in previous analyses for bio-oil pipelines (Pootakham and Kumar, 2010) and ethanol production facilities (Giarola et al., 2012). Although most economic variables are held constant, all scenarios are evaluated under a carbon price of $0 and $50 per tonne of carbon dioxide equivalents ($t\ CO_2$-e), in order to determine how a carbon tax, offset program, or trading scheme could influence design decisions that impact emissions at the construction and operating stages. This approach resembles the methodology applied by Giarola et al. (2012), in which ethanol supply chains were optimized with and without the introduction of a carbon trading scheme. Although future costs resulting from an emissions price are discounted, no steps are taken to differentiate the climate impacts from emissions that occur at different times. While this method of using a constant (100-year GWP) characterization factor is standard in conventional LCA, other methods explicate the significance of emissions timing in assessing climate impacts for projects that span many years (Brandão et al., 2013).

3. Results and discussion

3.1. Pumping energy intensity

Pumping energy intensity was calculated at both 272 and 307 K, corresponding to the estimated fluid temperature in underground pipelines in the coldest (winter in Wyoming) and hottest (summer in Arizona) soil regions in the United States, in order to estimate energy intensity under feasible high-density high-viscosity (272 K) and low-density low-viscosity (307 K) conditions. Fig. 1a presents the energy intensity per tonne of fluid pumped through pipelines up to an inner diameter (ID) of 24 inches (61 cm) for the five fuels at three different velocities with a fluid temperature of 272 K, corresponding with a conservatively high estimate of energy intensity for the contiguous United States (unit conversions for these values can be found in Table S5).

Temperature has the largest impact on the most viscous fuels: butanol, diesel, and biodiesel. For these fuels, the mass-based energy intensity in cold areas is estimated to be 1.19–1.21 times that of hot areas for pipelines with a 2-inch (5.1-cm) ID and 1.15–1.18 for pipelines with a 24-inch (61-cm) ID. For methanol and ethanol, the 35 degree difference only results in an energy intensity difference factor of 1.04 and 1.08–1.09, respectively.

The difference in mass-based pumping energy intensity is greater between the different fuels than between the same fuel at different temperatures, and is more pronounced at cold temperatures and slow velocities. For the fuels considered, the ratio of the energy intensity for the highest viscosity fluid (SME) to that of the lowest viscosity fluid (methanol) in 2-inch ID pipelines is 1.5–1.7 at 272 K and 1.2–1.4 at 307 K, with the low end of each range associated with a velocity of 3 m/s and the high end associated with 1 m/s. For 24-inch ID pipelines, this ratio ranges from 1.4 to 1.5 at 272 K and 1.2 to 1.3 at 307 K.

While mass-based energy intensity (kJ_e/t-km) enables comparison of the energy intensity of pipelines to alternative freight modes, dividing energy intensity by the energy content (defined as lower heating value, or LHV) of the fuel enables a useful comparison between different fuels. As an example of translating mass-based to energy-normalized units, 100 kJ per t-km would

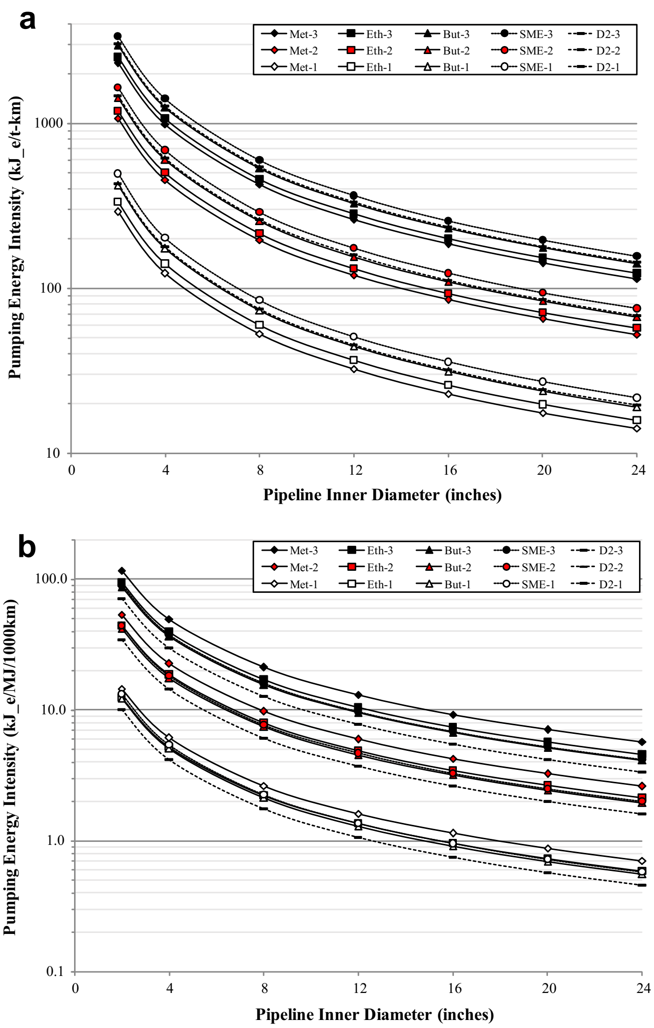

Fig. 1. Pipeline pumping energy intensity at fluid velocities of 1, 2, and 3 m/s, and fluid temperature of 272 K for five liquid fuels (Met = methanol, Eth = ethanol, But = butanol, SME = soy methyl ester biodiesel, and D2 = diesel) at interior diameters of 2–24 inches (5.1–61 cm). Energy intensity (to convert energy intensity to average national costs and emissions for 2011, the average US industrial electricity price was \$0.0189/MJ_e, and total emissions normalized to electricity sales yields an average emission factor of 178 g CO_2/MJ_e (US EIA, 2013a), though the annual non-baseload emission factor in 2009 was reported to be 196 g CO_2/MJ_e (US EPA, 2012)) is expressed per (a) unit mass of fuel transported (t-km) and (b) unit energy of fuel transported (MJ-1000 km). Legend convention: Fuel-Velocity (Pumping energy intensity values at 307 K are presented in Figs. S3 and S4.

be equivalent to 5.0 (methanol), 3.7 (ethanol), 2.9 (butanol), 2.7 (SME), and 2.3 (diesel) kJ per MJ per 1000 km. Fig. 1b presents pumping energy intensity values normalized to the energy content of the fuel. In contrast to Fig. 1a, the order of the fuels is nearly reversed as the high viscosity fuels also have high energy content (LHV) values, such that the pumping energy is equivalent to a smaller fraction of the fuels' energy content, and differences are more pronounced at higher temperatures, higher velocities, and larger diameters. For the fuels considered, the ratio of energy-normalized energy intensity for the most intensive fuel (methanol) to least intensive fuel (diesel) for 2-inch ID pipelines is 1.4–1.6 at 272 K and 1.7–1.8 at 307 K. For 24-inch ID pipelines, this ratio ranges from 1.5 to 1.7 at 272 K and from 1.7 to 1.9 at 307 K.

For the most part, results support existing advocacy for biofuel research and development efforts to target higher energy density fuels such as butanol over ethanol, which would improve the energy efficiency of fuel distribution with existing modes. However, although butanol would be more energy intensive to transport than SME biodiesel if distributed by conventional modes because it has a lower energy density than SME on a mass basis (8%) and volumetric basis (17%), it outperforms SME biodiesel on an energy-normalized basis if distributed through pipelines. Butanol is estimated to require up to 7% less energy per unit MJ if distributed through 2-inch pipelines (negligibly different at 3 m/s and 307 K), and up to 4% less in 24-inch pipelines (with an exception occurring at 3 m/s and 307 K, when butanol requires 1% more energy).

Within the fuels considered, the pipe diameter and the fluid velocity are the most critical determinants of energy intensity – far more significant than variations in viscosity between different fuels, or variations for the same fuel at different temperatures. Energy intensity varies by an order of magnitude over the three velocities considered (at a given diameter), and by more than an order of magnitude over the diameters considered (at a given fluid velocity). As shown in Table 2, the energy intensity of alternative modes is at least 1100 kJ/t-km for trucks, and at least 200 kJ/t-km for rail and barge. A comparison based strictly on energy intensity would suggest that pipelines are more energy efficient than trucks for an ID of 4 inches or greater (at a fluid velocity of 3 m/s or less), and are more energy efficient than rail and barge for an ID of 8 inches or greater (at a fluid velocity of 2 m/s or less) or for an ID of 12 inches or greater (at a fluid velocity of 3 m/s or less).

By the conventional measure of freight transportation energy intensity, the most energy intensive scenario (3400 kJ_e/t-km for SME at 3 m/s through a 2-inch pipe) is 240 times that of the least intensive scenario (14 kJ_e/t-km for methanol at 1 m/s through a 24-inch pipe). After normalizing to the fuel's energy content for a 1000 km pipeline, the most energy intensive scenario requires the electricity equivalent of 11.6% of methanol's energy content to transport it 3 m/s through a 2-inch ID pipe, which is 250 times greater than the least intensive scenario which requires the electricity equivalent of 0.05% of diesel's energy content to pump it 1 m/s through a 24-inch ID pipe. (The ratios would be 210 and 290, respectively, at 307 K.)

For reference, the national average (primary) energy used in oil pipelines was equivalent to 0.2% of the energy content of oil supplied in 1978 (Hooker, 1981), when the average total pipeline travel distance in 1980 was approximately 1,110 km (640 km for crude oil and 470 km for petroleum products) (Strogen, 2012). In a study comparing options to transport coal 1000 miles (1,609 km) by rail, by pipeline following minemouth gasification, or by 408 kV HVDC electric line following minemouth generation, energy losses were estimated at 2%, 3%, and 7% of the energy carried, respectively (Bergerson and Lave, 2005). As the environmental footprint of electricity is more heterogeneous than that of diesel, an environmental comparison requires consideration of location-specific electricity production emission factors in addition to energy intensity.

3.2. Ethanol and biodiesel pipeline scenarios

3.2.1. Pipeline design and initial cost results

For the scenarios considered, optimum pipeline (outer) diameters range from 4.5 to 4.9 inches for 0.3 MMtpy, 13.0 to 14.1 inches for 3.0 MMtpy, and 21.8 to 23.7 inches for 9.0 BGY. Operating fluid velocities range from 1.22 to 1.85 m/s (1.10–1.66 m/s annual average). Construction costs in 2009 USD (and construction GHG emissions in CO_2-e) were estimated in the range of \$101,000–\$141,000/km (40–42 t/km) for 0.3 MMtpy, \$290,000–\$403,000/km (140–154 t/km) for 3.0 MMtpy, and \$481,000–\$673,000/km (308–345 t/km) for 9.0 MMtpy. Construction costs vary due to input costs differences by region, and also because the optimum diameter is typically larger in states with high electricity costs.

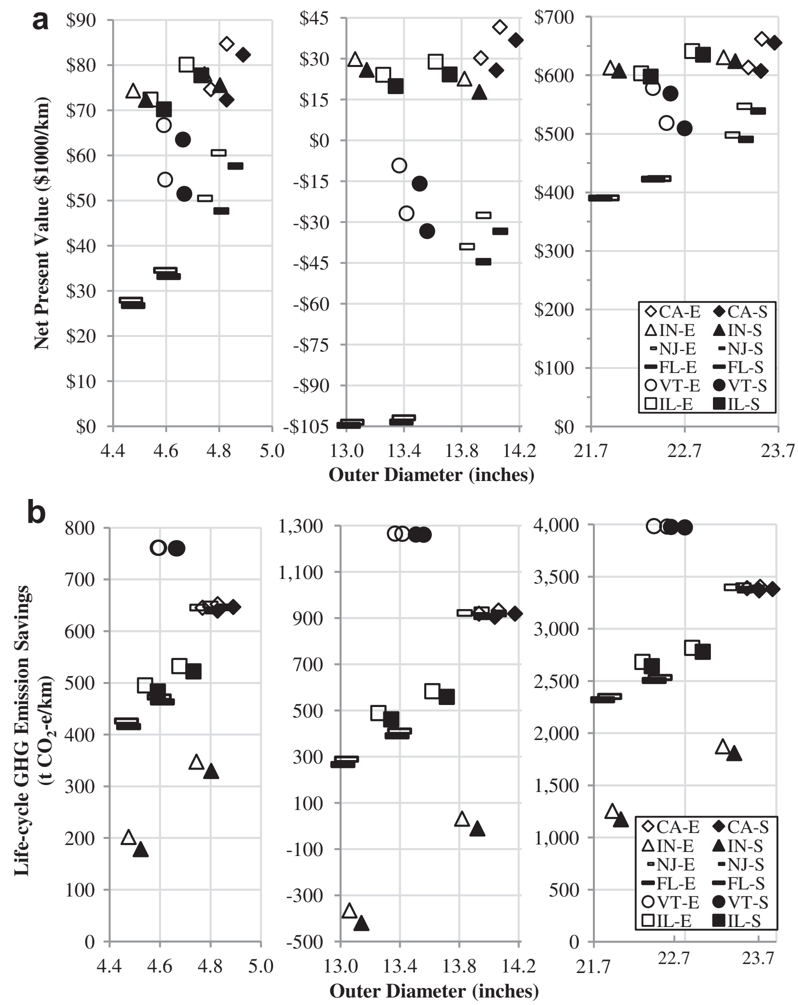

Fig. 2. Life-cycle (a) net present value and (b) GHG savings (over the assumed competing mode), presented against optimum pipe diameters, at a flow rate of 0.3 MMtpy on the left, 3.0 MMtpy in the middle, and 9.0 MMtpy on the right, for the biofuels ethanol (E) and soy methyl ester biodiesel (S) in six archetypal states. Legend convention: State-Fuel.

Pricing carbon would lead to a larger optimum pipeline diameter in all states except Vermont (where construction contributes more to life-cycle emissions than electricity), resulting in slightly greater construction emissions but lower life-cycle emissions. Although a $50/t carbon tax would have a negligible impact on pipeline design in Vermont, in carbon-intensive electricity states such as Indiana this price would result in an optimum design diameter up to 6% greater than the scenarios without a price on carbon. This design change would result in up to a 12% reduction in fluid velocity, enabling pipelines to reduce operational energy and GHG intensity by up to 26%, thereby reducing expected annual operating emissions up to 8 t CO_2-e/km for 0.3 MMtpy pipelines, 21 t CO_2-e/km for 3.0 MMtpy pipelines, and 34 t CO_2-e/km for 9.0 MMtpy pipelines.

3.2.2. Life-cycle profitability and emissions

Fig. 2 presents the life-cycle net present value (a) and GHG emissions (b) per km, presented against the optimum OD for each pipeline scenario. The net present value of pipelines (and life-cycle avoided GHG emissions in CO_2-e) is in the range of $27,000–$85,000/km (180–760 t/km) for 0.3 MMtpy, [−$105,000]–$42,000/km ([−420]–1,300 t/km) for 3.0 MMtpy, and $390,000–$662,000/km (1,200–4,000 t/km) for 9.0 MMtpy. For all scenarios and conditions evaluated, initial construction costs contribute 69–72% of total project life-cycle costs; however, initial construction emissions contribute as little as 6–10% to life-cycle GHG emissions in Indiana, 10–20% in Illinois and Florida, 22–31% in California and New Jersey, and up to 62% in Vermont. Electricity, while only contributing 7–13% to project life-cycle costs across all scenarios, contributes anywhere from 1% of life-cycle GHG emissions in Vermont up to 90% of emissions in Indiana if carbon is not priced. The existence of a $50/t price on carbon ensures that pipelines in each scenario would generate net GHG savings over their life cycle, and also increases pipeline profitability in all states. A sensitivity analysis, described in section SD-2, was performed to estimate how changes to other input variables may affect project NPV.

3.2.3. Payback period estimation

From an economic perspective, after operations begin (assumed to be two years after the investment is made), pipelines are estimated to have a payback period of 6.6–13 years for the 0.3 MMtpy scenarios (versus truck), 14 years to never for the 1 bgy scenarios and 4.8–8.0 years for the 9 MMtpy scenarios (both versus rail). For each flow rate, the shortest economic payback period would occur in California under a carbon price of $50/t, and the only scenarios in which a pipeline would never break even occur at a throughput of 3.0 MMtpy for either fuel in Florida (whether or not carbon is priced).

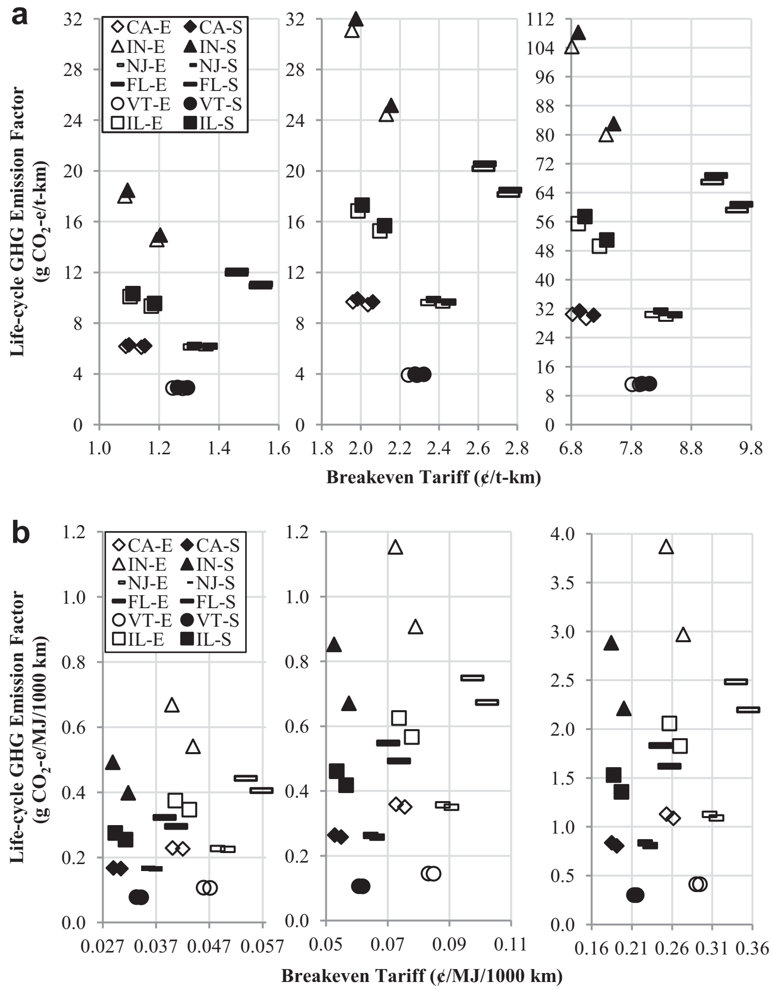

Fig. 3. Life-cycle GHG emission factors and breakeven tariff price expressed (a) per t-km and (b) per MJ-1000 km, at a flow rate of 9.0 MMtpy on the left, 3.0 MMtpy in the middle, and 0.3 MMtpy on the right, for the biofuels ethanol (E) and soy methyl ester biodiesel (S) in six archetypal states. Legend convention: State-Fuel.

From a GHG emissions perspective, the payback periods range from 1–4 years for the 0.3 MMtpy scenarios, 2 years to never for the 1 bgy scenarios, and 1.5–4.2 years for the 9 MMtpy scenarios. Vermont has the shortest GHG payback periods (negligibly shorter with a price on carbon), whereas the only scenarios in which a pipeline would never generate net GHG savings occur at a throughput of 3.0 MMtpy for either fuel in Indiana if carbon is not priced. Formulas used to estimate breakeven periods can be found in SD-3.

3.2.4. Normalizing costs and GHG emission factors

Fig. 3 presents the life-cycle emission factors normalized to mass (a) and energy (b), presented against the minimum breakeven tariff of these pipelines. This normalization of units per t-km of fuel transported enables easier comparison to alternative transportation modes. For the 0.3 MMtpy scenarios, the breakeven tariff for pipelines would be in the range of \$0.068–\$0.096/t-km, and in energy-normalized units 0.18–0.35 ¢/MJ/1000 km (which translates to 22–43 cents per gallon of gasoline equivalent of delivered fuel per 1000 km (¢/gge/1000 km)). Therefore, such small pipelines would not be competitive with long-distance rail and barge, but would be competitive with trucking (which is assumed to cost \$0.10/t-km without a carbon price and \$0.107/t-km with a carbon price of \$50/t CO_2-e). With emission factors ranging from 11 to 108 g CO_2-e/t-km, 0.3 MMtpy pipelines would generate fewer GHG emissions than trucks in all states, comparable emissions to rail and barge in California and New Jersey, and lower emissions than all three modes in Vermont.

For the 3.0 MMtpy and 9.0 MMtpy scenarios, pipelines are primarily compared to rail; rail transportation is assumed to cost \$0.020/t-km without a carbon price, and \$0.0213/t-km with a carbon price of \$50/t CO_2-e. For reference, barge transportation is assumed to cost \$0.015/t-km without a carbon price, and \$0.0165/t-km with a carbon price of \$50/t CO_2-e. Under the 3.0 MMtpy scenarios, the breakeven tariff for pipelines is \$0.019–\$0.028/t-km, and in energy-normalized units 0.05–0.10 ¢/MJ/1000 km (6–12 ¢/gge/1000 km), thus being competitive with rail for both fuels in California, Illinois, and Indiana, but not competitive for either fuel in Florida, New Jersey, or Vermont. With a GHG emission factor of 3.9–32 g CO_2-e/t-km, 3.0 MMtpy pipelines generate fewer emissions than rail or barge in all scenarios except in Indiana if carbon is not priced. For the 9.0 MMtpy scenarios, the breakeven price for pipelines is \$0.011–\$0.015/t-km, and in energy-normalized units 0.029–0.057 ¢/MJ/1000 km (3–7 ¢/gge/1000 km), thus outcompeting all three modes in all states for both fuels. With an emission factor of 2.9–18 g CO_2-e/t-km, such a large pipeline would also generate fewer emissions per unit of fuel delivered than the three alternative modes in all states for both fuels.

3.3. Shortcomings in addressing data quality and variability

Although the modeling employed in this analysis incorporates multiple techno-economic relationships, results should be considered insightful but limited. Data quality varies, as some data were selected or generated with a high degree of specificity, whereas modeled cost and GHG emissions values of many activities were estimated using older and overly aggregated data sources, and were assumed to be static over time. In modeling construction and operation of pipelines and alternative modes, many plausible decisions and sources of temporal and spatial uncertainty and variability were not explicitly addressed.

3.3.1. Uncertainty in design and economic assumptions

Although assumptions about the project discount rate (10%) and lifespan (20 years) may be considered pessimistic for petroleum pipelines, perceived risks related to the longevity of biofuel support policies (and to a lesser extent technical risks associated with biofuels) may lead investors to expect an even greater rate of return or shorter payback period.

For all scenarios considered, construction costs contribute approximately 70% to the life-cycle costs of pipelines, rendering results extremely sensitive to initial costs. Although construction costs are not expected to decrease much over time as a result of learning, due to the maturity of pipeline construction practices (van der Zwaan et al., 2011), pipeline delays and construction costs are notoriously difficult to predict, and costs have also increased since the cost model was initially developed (Smith, 2012).

3.3.2. Uncertain future conditions

The economic performance of pipelines relative to alternative modes partially depends on the future energy intensity and fuel costs for each mode. By 2030, national average electricity prices are projected to rise 9% to \$0.070/kWh (\$0.019/MJ_e) for the industrial sector, while diesel prices are expected to rise 27% to \$4.27/gallon (\$1.13/L), expressed for reference case scenarios in 2011 USD (US EIA, 2013a). However, by 2030, significant energy efficiency gains could enable energy intensity improvements of 15–30% for medium and heavy-duty trucks, 15–17% for rail, and 40% for marine transport, but only 10% for pipelines (US DOE, 2013). In terms of GHG emissions, a potential future advantage for pipelines is the projection that US electricity will decrease in carbon intensity by 6–7% by 2030 (US EIA, 2013a), while making a comparable reduction in the carbon intensity of freight transportation fuels is likely to remain a significant challenge. Pipelines would be less susceptible to local and national electricity trends if their construction involved coordinated expansion of a specific electricity generation technology.

3.3.3. Unaddressed spatial heterogeneity

Although the spatial resolution of the pipeline construction cost model is limited to multi-state regions, the economic and energy intensity factors for alternative (non-pipeline) modes were not assumed to vary by region or scale. In evaluating biofuel transportation options in future case studies, instead of using national average and characteristic values, corridor-specific energy intensity should be estimated to account for elevation changes and infrastructure circuity, in addition to case-specific implications for upgrading infrastructure or expanding energy production to accommodate increasing loads. In case studies outside of the United States, attention should be given to unique construction challenges and costs, interest rates, electricity prices, and electricity emissions.

3.4. Policy implications

For biofuels to qualify under the Renewable Fuel Standard as "advanced", they must have a life-cycle GHG footprint less than 47 g CO_2-e/MJ. If biofuels continue being transported on average over 1000 km as ethanol has been, fuel transportation will make up a growing percentage of total supply chain GHG emissions. Transporting fuel 1000 km by a characteristic truck would result in a contribution to life-cycle emissions of 5.1 g CO_2-e/MJ for ethanol and 3.7 g CO_2-e/MJ for SME, and 1000 km by rail or barge would contribute around 0.9 g CO_2-e/MJ for ethanol and 0.7 g CO_2-e/MJ for SME biodiesel. Under the most GHG-intensive scenarios, pipelines evaluated in this study could contribute up to 3.9 g CO_2-e/MJ for 0.3 MMtpy pipelines, 1.2 g CO_2-e/MJ for 3.0 MMtpy pipelines, and less than 0.7 g CO_2-e/MJ for 9.0 MMtpy pipelines per 1000 km.

As a result, pipelines cannot be categorically assumed to generate fewer GHG emissions than alternative modes. Even medium-sized pipelines (over 12 inches) will have a greater GHG emissions intensity than rail and barge if operated to maximize profits in high-carbon low-cost electricity states. For policy makers interested in reducing GHG emissions through subsidizing pipelines, constructing the pipeline is only the first step; by putting a price on carbon emissions, pipeline designers and operators are more likely to select a design velocity that results in system-wide life-cycle emission savings. Although a carbon price of \$50/t CO_2-e would increase the optimum fluid velocity (and energy intensity) in extremely low-carbon electricity states such as Vermont, it would typically reduce the optimum fluid velocity (reducing pumping energy intensity up to 26%) in high-carbon electricity states. Although generously funding infrastructure reduces long-term operating costs for many industries, pipelines are unique in that operating energy can be reduced approximately 50% by choosing a 15% larger diameter. Given the difficulty of reducing transportation sector GHG emissions over the coming decades (Dray et al., 2012), favoring wider-than-conventional diameter pipelines may be a cost effective way to reduce GHG emissions.

In addition to evaluating the economic feasibility and GHG emissions implications of pipelines, more comprehensive comparison to alternative modes would require case-specific consideration of metrics related to wildlife and biodiversity; noise, water, and air pollution; public health and safety impacts from pollution and accidents; disturbance of historically or culturally significant lands; congestion along alternative freight corridors; and assessment of indirect economic impacts.

4. Conclusion

Costs and emissions from liquid biofuel pipelines depend on location, diameter, and fluid velocity. Although fuel type and temperature matter, throughput-normalized energy intensity varies by two orders of magnitude over the diameters and velocities evaluated (2–24 inches; 1–3 m/s). Constructing pipelines may enhance societal welfare through greater cost-effectiveness and fewer GHG emissions than alternative modes; in hypothetical scenarios, 0.3 MMtpy pipelines outperform trucks, 3.0 MMtpy pipelines often outperform trains and barges, and 9.0 MMtpy pipelines outperform all three modes. Carbon pricing typically increases pipeline cost-effectiveness, decreases life-cycle GHG emissions, and (unless pumps use low-carbon power) increases optimum diameter.

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Appendix A. Supplementary data

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.biortech.2013.08.150.

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