Production of Bio-Synthetic Natural Gas in Canada

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Large-scale production of renewable synthetic natural gas from biomass (bioSNG) in Canada was assessed for its ability to mitigate energy security and climate change risks. The land area within 100 km of Canada's network of natural gas pipelines was estimated to be capable of producing 67–210 Mt of dry lignocellulosic biomass per year with minimal adverse impacts on food and fiber production. Biomass gasification and subsequent methanation and upgrading were estimated to yield 16 000–61 000 Mm^3 of pipeline-quality gas (equivalent to 16–63% of Canada's current gas use). Life-cycle greenhouse gas emissions of bioSNG-based electricity were calculated to be only 8.2–10% of the emissions from coal-fired power. Although predicted production costs ($17–21 GJ^{-1}) were much higher than current energy prices, a value for low-carbon energy would narrow the price differential. A bioSNG sector could infuse Canada's rural economy with $41–130 billion of investments and create 410 000–1 300 000 jobs while developing a nation-wide low-carbon energy system.

1. Introduction

In North America, the demand for natural gas is expected to continue to rise as a result of a growing population and fuel shifting in response to high oil prices and concerns about the carbon/greenhouse gas (GHG) intensity of coal-fired power generation (*1*, *2*). However, Canadian natural gas production is expected to peak by 2011 and then slowly decline thereafter (*2*). Although this decline may be partially or fully offset by shale gas production, especially in the US (*1*), there is interest in finding alternative Canadian sources of natural gas.

Synthetic natural gas (SNG) from either anaerobic digestion or gasification of biomass has attracted attention because it can be produced from a wide range of feedstocks while generating a low carbon footprint. Anaerobic digestion to a methane-rich biogas and upgrading can be used with wet biomass sources such as manure and organic waste. However, for most feedstocks, relatively little (<35%) of the thermal energy content of the feedstock ends up as SNG (*3*). This is especially the case for lignocellulosic biomass such as forest residues or straw that can be readily grown in Canada. For such biomass feedstocks, gasification, followed by methanation and upgrading can produce a bioSNG with 55–70% of the energy in the feedstock at large scales and more rapidly (*4–7*). For these reasons, this preliminary environmental and economic study focuses on the gasification and subsequent processing to bioSNG of a wide range of lignocellulosic biomass feedstocks that can be grown in lands near the nation's network of natural gas pipelines. A systems approach was used to assess the bioSNG production potential of lands adjacent to Canada's pipelines and track the flows of mass and energy throughout the process while assessing life-cycle energy use, GHG emissions, and economic costs using a range of assumptions.

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2. Methodology

To model bioSNG production from the field to the pipeline, a set of boundary conditions were defined as illustrated in Figure S1 of the Supporting Information.

The analysis began with an assessment of the sustainable biomass production capacity of the land adjacent to Canada's existing network of natural gas pipelines. Sustainability was defined as the ability to produce biomass in perpetuity while limiting adverse impacts on the environment (water use, biodiversity, nutrient loading, etc.) and on food and fiber production.

Biomass was then transported to processing sites along the pipeline where it was first gasified into a syngas (predominantly carbon monoxide and hydrogen), converted to methane, upgraded to natural gas quality, and compressed into the pipeline. Gasification plants were assumed to be spaced at regular intervals along the pipeline. Greater spacing required larger gasification plants and longer biomass transportation distances. The analyses determined mass and energy flows for different scales of operation from which life-cycle direct energy use, GHG emissions, and economic costs could be evaluated.

Two basic scenarios were assessed, each scenario defined by a number of "base case" or "optimistic" assumptions for parameters such as land area available, biomass productivity, and conversion efficiency. The "base case" was a best estimate of parameter values whereas the "optimistic" scenario was based on advanced technologies and policies that work to maximize bioSNG production. Throughout the paper, base case assumptions and calculated values will be presented in the flow of the text, whereas optimistic values will be shown in parentheses (i.e., {...}) if they differ from the base case.

2.1. Land Area. In Canada, most natural gas pipelines originate in western Canada (northern British Columbia, Alberta, and Saskatchewan) and extend to population and industrial centers across the country. A scaled map of Canada's pipelines (*8*) and a reference map with updated information were used to calculate Canadian land area located within 50 {100} km of one or more pipelines (see Figure S2 of the Supporting Information). Land areas were assigned to one of three categories: forest, good agricultural, or marginal based on current land use practices, soil types, and water availability (*9*, *10*). Table 1 summarizes the base case and optimistic land area estimates.

2.2. Forest Biomass Production. Forest biomass was assumed to be derived from two major sources: residues from existing forestry and whole trees. To calculate residue availability, 80% of the forest land area was assumed to be managed and harvested by clear-cutting at a rate of 0.60% {0.48%} of the managed land area per year. The base case estimate (0.60%) was based on current harvest rates (*11*), whereas the optimistic estimate (0.48%) predicted a 20% decline due to pulp and paper mill closures. Mill closures reduced residue availability from conventional harvesting

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TABLE 1. Assumed Parameters and Results for the Base Case (A) or Optimistic (B) Estimate of Land Area and Biomass Production within 50 or 100 km of Natural Gas Pipelines for Forest (FOR), Good Agriculture (GA), and Marginal (MAR) Land

land type	land area (Mha)	biomass type	accessible land area (% y^{-1})	yield (t(dry) ha^{-1})	available land area (Mha y^{-1})	biomass (Mt(dry) y^{-1})
			A. base case			
FOR	68	residues	0.48	25	0.33	8.2
		whole trees	0.15	110	0.10	11
GA	34	residues	49	0.50	16	8.2
		biomass crops	6.5	8.0	2.2	18
MAR	34	biomass crops	10	6.4	3.4	22
total	**136**				**23**	**67**
			B. optimistic			
FOR	98	residues	0.38	34	0.38	13
		whole trees	0.47	130	0.46	61
GA	49	residues	48	0.75	23	17
		biomass crops	10	12	4.9	58
MAR	49	biomass crops	15	8.5	7.4	62
total	**196**				**36**	**210**

but expanded the resource base for bioenergy applications. On the harvested land, average total production was 120 {140} t(dry) ha^{-1} where 30% of the biomass was residue of which 70% {80%} could be sustainably removed. Previous estimates vary widely for the amount of residues that need to be left at the harvest site to prevent erosion, maintain soil carbon stocks, protect emerging tree seedlings, and minimize moisture loss from the forest floor (*12*). This study assumed that, on average, 70% {80%} of residues could be sustainably removed although the actual amount depends on local site characteristics.

The biomass potential of whole trees was estimated based on harvesting the unused annual allowable cut (AAC), trees killed by fire, pests, and disease, and replanting with fast-growing species. Some of this biomass may also come from diverting resources from pulp and paper systems, which have been in decline due to changing global markets (*13*). Another possibility is to make more of Canada's forests available for harvesting since only half of potentially harvestable forests are subject to management practices (*11*). Additional resources could be procured by harvesting the unused portion of the AAC (approximately 20%) or by replanting with fast-growing species such as poplar and willow. Overall, an additional 0.15% {0.47%} of forested land could be harvested each year at 120 {140} t(dry) ha^{-1} where 91% {94%} of the biomass could be sustainably removed.

2.3. Agricultural Biomass Production. Agricultural biomass for energy was assumed to come from food/forage crop residues and dedicated biomass crops. The estimated 17 {25} Mha of good agricultural land reserved for food/feed production within 50 {100} km of pipelines was estimated to produce 1.0 {1.5} t(dry) ha^{-1} of residues (*14, 15*). However, only 50% of residues were predicted to be available (*12*).

Dedicated biomass crops such as switchgrass were assumed to be grown on 10% {15%} of the total marginal land area at a productivity of 8 {10} t(dry) ha^{-1} (*16*). These crops were also grown on diverted pasture and feed production land since it was assumed that domestic ruminant production would decline given concerns about the GHG footprint of meat production (*17*) and the effect of biomass markets on land values and animal feed costs. Biomass production was calculated on 20% {30%} of the estimated 8.5 {12} Mha of pasture land and 3% {5%} of the 17 {25} Mha of cropland at 10 {14} t(dry) ha^{-1} (*18*). Of the dedicated production, 80% {85%} of the aboveground biomass could be available for energy use.

2.4. Mass, Energy, and GHG Emissions. The material and energy flow (Figure 1) was based on 1 dry tonne each of forest and agricultural biomass while dry matter losses were estimated from the literature (*19*). A lower heating value (LHV) of 9.2 and 12.4 GJ t(wet)$^{-1}$ was calculated from a higher heating value of 20.0 and 18.5 GJ t(dry)$^{-1}$ (*16*), hydrogen content of 6.0% and 5.5% (dry basis) (*20*), and moisture content of 45% and 25% for woody and herbaceous biomass, respectively.

Biomass production required natural gas, diesel, and electricity inputs for fertilizer production, harvesting operations, and preprocessing. Energy inputs were estimated from the literature (*21*), and their associated GHG emissions were calculated using life-cycle emission factors for diesel (*22*), natural gas (*23*), and electricity (*24*). Improved production technology reduced energy inputs by 15% in the optimistic scenario (*21*).

Herbaceous crops required the application of synthetic nitrogen (N) fertilizer at a rate of 5 kg N per harvested dry tonne, which leads to GHG emissions of nitrous oxide (N_2O). As a reference, biomass crops producing 12 t(dry) ha^{-1} required 60 kg ha^{-1} of fertilizer and released 0.5 kg N_2O-N ha^{-1} of direct and indirect emissions (*25*). Emissions were calculated in proportion to this reference case. A 100-year global warming potential of 310 was used to convert N_2O emissions into CO_2-equivalents (CO_2e) (*25*).

Since thermochemical conversion processes operate more efficiently with low-moisture feedstocks, biomass was dried to 15% moisture, which increased LHV but resulted in an additional 3% loss of dry matter when combined with losses associated with storage. A previous study investigating the GHG emissions resulting from the storage of wood chips (moisture content 40−60%) over a 6-month period found that emissions ranged from 16−40 kgCO_2e GJ^{-1} (*26*). Our model predicted that woody and herbaceous biomass was dried to 15% moisture before storage, which minimized

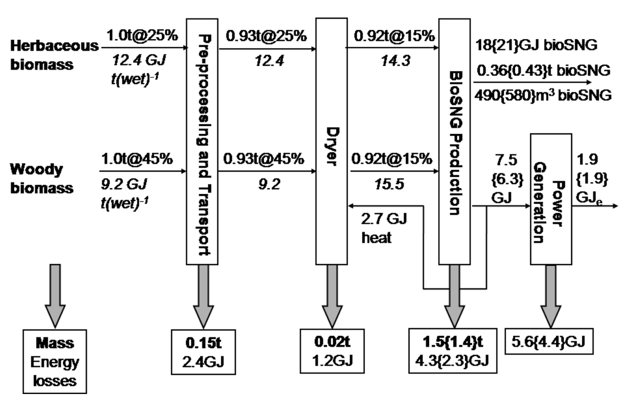

FIGURE 1. Base case {optimistic} estimates of mass and energy flow in the bioSNG production process assuming inputs of 1 tonne herbaceous biomass at 25% moisture plus 1 tonne woody biomass at 45% moisture. All weights in bold are dry tonnes while lower heating values (LHVs) are in *italics*.

methane and N_2O production. Altogether, dry matter losses prior to gasification were 8% (*19*).

Dry biomass was converted to bioSNG through gasification and subsequent methanation of the syngas. We assumed the use of a pressurized, oxygen-blown gasifier because of its good scale-up potential and ability to produce a nitrogen-free syngas (*27, 28*). The methanation system selected was based on adiabatic reactors and intermediate cooling (*29*), followed by removal of CO_2 to yield pipeline-quality gas. Attaining a tar-free syngas cleaned of impurities that could foul downstream catalytic equipment is the primary technical challenge in commercialization of biomass gasification (*30*). In comparison, methanation (*31*) and CO_2 removal (*3*) are mature technologies. Base case {optimistic} estimates of the energy conversion efficiency of biomass to bioSNG were 55% {65%}. Therefore, for every 2 dry tonnes of biomass (half forest, half agricultural), 18 {21} GJ of bioSNG was produced.

A large amount of exothermic heat was generated during bioSNG production. It was assumed that 70% {80%} of the heat was used in drying and a power generation cycle while 30% {20%} was lost to the surroundings. The dryer's heat demand was determined based on the rate of water removed from the incoming feedstock at 80% efficiency. The remaining useful heat was used in a power generation cycle at an electrical efficiency of 25% {30%} (*24*), which produced 1.9 {1.9} GJ of electricity. BioSNG production was estimated to require 330 kWh of electricity per tonne of dry biomass harvested (*32*), which was partially met by auxiliary power.

2.5. Economics. Overall production costs were calculated as the sum of delivered feedstock, capital, and operating costs. The delivered cost of biomass was broken down into the cost of producing wood chips (*33*) or straw bales (*25*) and truck transportation (*34*) to a storage facility adjacent to the plant. Although technological improvements reduced energy inputs in biomass production in the optimistic scenario, the price of biomass was not assumed to change due to higher seed and equipment costs, and greater demand for biomass.

Economies of scale decreased unit capital costs at larger plant sizes. Scale factors derived from studies on biomass gasification (*27, 28*) and methanation (*29*) were used to calculate investment and operating costs at different plant sizes. Investment costs were then amortized over a 20-year project lifetime at 10% interest and added to annual feedstock and operating costs to determine total production costs. Unless otherwise stated, all costs were calculated as 2005 USD.

3. Results and Discussion

3.1. Canadian Biomass Potential Adjacent to Natural Gas Pipelines. The land area within 50 {100} km of pipelines was estimated to be 136 {196} Mha (Table 1), equivalent to 14% {20%} of Canada's total land area (980 Mha) (*11*). However most of this land is in southern Canada, where biological resources are abundant. About 50% of the adjacent land was assessed to be forest, 25% agriculture, and 25% marginal.

Residues from Existing Forest and Agricultural Production. Using the assumptions identified in the footnotes to Table S1 (see the Supporting Information), forest and agricultural residues contributed 8.2 {13} and 8.2 {17} Mt(dry) y^{-1} of bioenergy potential, respectively.

To put these values into perspective, residues from traditional forest harvesting were estimated from 2004 values for the Canadian harvest of industrial roundwood (206 Mm^3 or 90 Mt(dry)) (*11*). Assuming roundwood represented 70% of the total harvest, with 30% as residue, the residue fraction would be 40 Mt(dry). Therefore, sustainable forest residues adjacent to pipelines would be 21% {33%} of Canada's total forest residues.

Moreover, average annual food crop residues from 2003 to 2007 were 55 Mt(dry) (*14*). Therefore, sustainable agricultural residues adjacent to pipelines would be 15% {31%} of Canada's total crop residues.

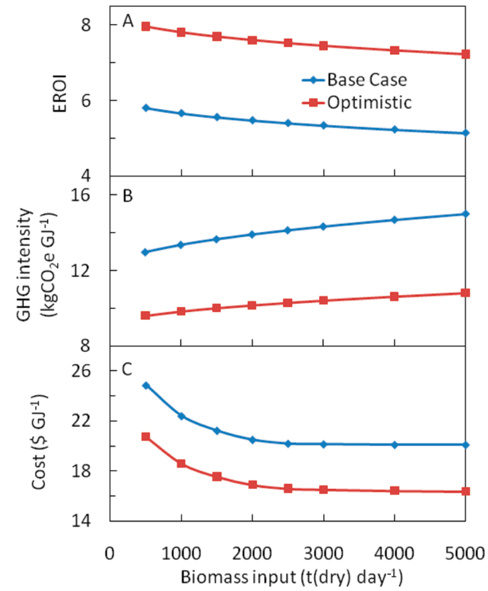

FIGURE 2. Base case and optimistic estimates of EROI (A), GHG intensity (B), and cost (C) of bioSNG at different scales of operation.

Whole Forest Harvest. Given the assumptions in Table S1, we estimated that 0.10 {0.46} Mha y^{-1} of forest land could be harvested for energy production, thereby providing 11 {61} Mt(dry) y^{-1} of biomass. The primary sources were trees having little commercial value such as dead trees, trees in unmanaged forests, and trees unused by the forestry sector. To put this into perspective, these values are equivalent to 11% {51%} of the annual forest harvest (0.9 Mha y^{-1}) and 12% {68%} of the 2004 roundwood harvest in Canada.

Biomass Crops. The potential of biomass crops was calculated from estimates of total good agricultural and marginal land area adjacent to pipelines as well as assumptions regarding accessible land area and biomass yields on the different land types. A total of 2.2 {4.1} Mha of good agricultural land (equivalent to 3.2% {6.0%} of the estimated 68 Mha of farmland in Canada (*35*)) was calculated to be available to produce 8.0 {12} t(dry) ha^{-1} when 20% {15%} of the crop was left in the field, yielding 18 {58} Mt(dry) y^{-1}. In comparison, 3.4 {7.4} Mha of marginal land (equivalent to 20% {44%} of the estimated 17 Mha of unused marginal land suitable for biomass crops in Canada (*36*)) was calculated to be available to produce 6.4 {8.5} t(dry) ha^{-1} when 20% {15%} of the crop was left in the field, yielding 22 {63} Mt(dry) y^{-1}.

The potential from residues, whole trees, and biomass crops within 50 {100} km of pipelines was combined to generate an estimate of 67 {210} Mt(dry) or 1100 {3500} PJ y^{-1} of thermal energy, a value equivalent to 8.9% {28%} of Canada's total primary energy demand in 2004 (12.3 EJ) (*2*).

3.2. Canadian BioSNG Potential. On the basis of the calculated efficiencies of mass and energy flow (Figure 1) and the estimated potential for sustainable biomass production in the corridor around natural gas pipelines (Table 1), total bioSNG production was predicted to be 16 000 {61 000} Mm^3 y^{-1}. Since Canada's gas consumption was 97 000 Mm^3 in 2004 (*2*), bioSNG could fulfill 16% {63%} of current domestic demand.

3.3. Scale Effects. The effects of the scale of biomass transportation and processing on life-cycle energy use, GHG emissions, and economic costs were calculated for plant operations ranging from 500−5000 t(dry) biomass harvested per day. The energy return on investment (EROI) was calculated as the ratio of useful energy produced to life-cycle direct energy use. Larger scales of operation were predicted to lower EROI (Figure 2A) and increase GHG intensity (Figure

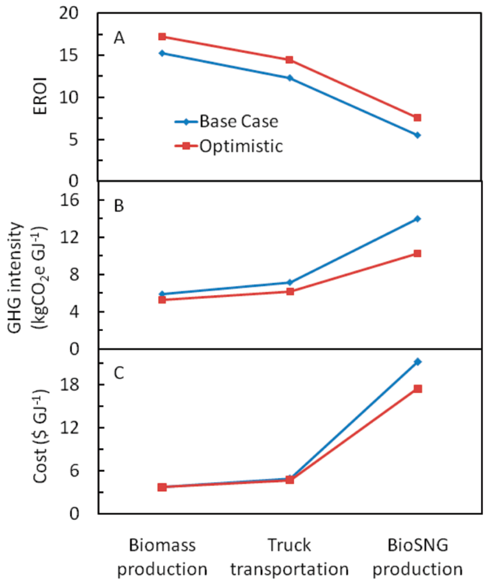

FIGURE 3. Base case and optimistic estimates of EROI (A), GHG intensity (B), and cost (C) of bioSNG at different stages in production.

2B) due to higher diesel use over longer transportation distances. The optimistic EROI estimate ranged from 7.2−8.0 (unitless), which was higher than the base case (5.1−5.8) due to fewer energy inputs in biomass production and higher energy conversion efficiencies. As a comparison, the EROI of corn-based ethanol and synthetic crude from oil sands (excludes energy involved in mining and transporting the raw oil sands) has been reported as 0.8−1.6:1 (*37*) and 5:1 (*38*), respectively. The conversion efficiency to bioSNG was assumed to be independent of scale for the type of gasifier considered (*39*).

The economy of scale was most pronounced at small plant sizes (Figure 2C). Capital cost reductions were estimated by an overall scale factor of 0.74 for plants up to 400 MW_{th} and 0.91 for larger sizes (*27*). The base case estimate ($20−25 GJ^{-1}) was about 20% higher than the optimistic estimate ($16−21 GJ^{-1}). Although larger plant sizes resulted in higher biomass transportation costs, overall production costs plateaued beyond 2500 t(dry) day^{-1} (equivalent to a thermal input slightly more than 400 MW_{th}) as economies of scale canceled out escalating transportation costs. This type of cost profile is common in biomass projects (*40, 41*).

3.4. System Components. The supply chain consisted of biomass production, transportation, and bioSNG production. Average values of EROI, GHG intensity, and cost were calculated from scales ranging from 500 to 5000 t(dry) day^{-1}. The EROI declined from 15 {17} to 5.5 {7.6} (Figure 3A) while the carbon footprint increased from 5.9 {5.2} to 14 {10} kgCO$_2$e GJ^{-1} (Figure 3B) mainly due to conversion losses during bioSNG production.

Production costs increased as biomass was transformed into more useful forms of energy (Figure 3C). Costs increased about 5-fold from $3.8 {$3.7} GJ^{-1} for virgin biomass to $21 {$17} GJ^{-1} for bioSNG. A combination of high capital costs and energy losses made bioSNG production the largest contributor to overall costs.

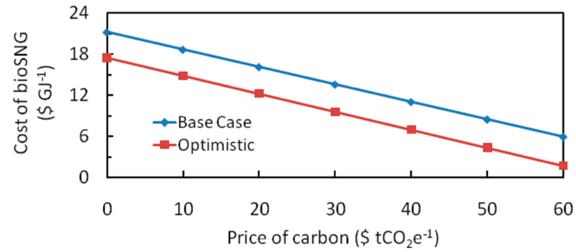

FIGURE 4. Base case and optimistic estimate of bioSNG production costs at different carbon prices when replacing coal as a feedstock for power generation.

3.5. Sensitivity Analysis. A sensitivity analysis was performed to ascertain the impact of key parameters on calculated values of EROI, GHG intensity, and cost (Table 2). The analysis was conducted by independently varying key parameters in the base case scenario such as the price of biomass, energy and economic cost of transportation, bioSNG conversion efficiency, energy recovered in bioSNG plant, and bioSNG plant electricity demand. All parameters were increased 20% above the base case.

Energy recovery and electricity demand had the most impact on EROI. Recovering a larger fraction of energy from the process increased auxiliary power generation and substantially raised the EROI while increasing electricity demand had the reverse effect. The corresponding impact on GHG intensity was not as pronounced because of the low carbon footprint of Canada's electricity sector (224 gCO$_2$e kW^{-1} h^{-1}) (*24*).

Although perturbing bioSNG conversion efficiency had widespread impact, its most profound effect was on cost. A 20% increase in bioSNG production decreased costs by 16%, but the higher conversion rate reduced energy recovery, which increased electricity demand.

Sensitivity to variations in the price of biomass and truck transportation was not as significant. The design and integration of the bioSNG production facility and the conversion efficiency were the most important parameters.

3.6. Comparison to Fossil Fuels. A low carbon footprint and high electrical conversion efficiency (45% compared with 33% for coal) could make bioSNG an effective substitute for coal as a feedstock for power generation. The calculated GHG intensity of bioSNG-based electricity was only 8.2−11% of the life-cycle emissions of coal-fired power (1030 kgCO$_2$e MW^{-1} h^{-1}) (*23*). However, production costs were higher than average coal prices ($2−3 GJ^{-1}).

BioSNG could be cost competitive by placing a value on the GHG benefits relative to coal. Figure 4 shows how the price of carbon affects the cost of bioSNG when replacing coal as a feedstock for power generation. When GHG emission reductions had zero value, the feedstock cost was simply the production cost of bioSNG ($21 {$17} GJ^{-1}). However, at $60 tCO$_2$e^{-1}, costs decreased to $6.0 {$1.7} GJ^{-1}, which makes bioSNG cost competitive with coal as a feedstock for power generation.

TABLE 2. Sensitivity of EROI, GHG Intensity, and Cost of bioSNG to Changes in Key Parameters

parameter	EROI	GHG intensity (kgCO$_2$e GJ^{-1})	cost ($ GJ^{-1})
base case	**5.5**	**14**	**21**
price of biomass (+20%)	0%	0%	+6.4%
energy and economic cost of transportation (+20%)	−2.2%	+2.8%	+1.9%
bioSNG conversion efficiency (+20%)	−12%	−3.7%	−16%
energy recovered in bioSNG plant (+20%)	+43%	−13%	−0.73%
bioSNG plant electricity demand (+20%)	−22%	+12%	+1.9%

There are additional benefits associated with a national bioSNG strategy that are harder to account for but important from a public policy perspective. For example, the industry would directly impact rural communities in need of an economic stimulus. If Canada's annual potential was 16 000 {61 000} Mm^3 and a 400 MW_{th} plant produced 230 {270} MW of bioSNG, 89 {280} such plants would be required. The cost of a 400 MW_{th} plant was estimated to be $460 million (*27–29*), leading to a total investment of $41 {$130} billion over a 20-year period. Since the bioenergy sector produced 10 jobs for every $1 million invested (*42*), rural economic development could be promoted through the creation of 410 000 {1 300 000} new jobs.

While large-scale bioSNG production could offer benefits for energy security, climate change, and rural economic development, it may also have adverse environmental and socio-economic impacts. Competition for access to productive agricultural land could increase food prices or drive deforestation in an effort to replace displaced agricultural production (*43*). If poorly managed, land use change towards biomass production could generate a "carbon debt" that could take many years to repay (*44*) and destroy biodiversity. Higher rates of fertilizer and water use to improve biomass productivity could impair water resources (*43*) and adversely impact biodiversity.

Nevertheless, properly managed and regulated, a national bioSNG strategy could support the decarbonization of Canada's energy system by providing a major new fuel to take market share from more carbon-intense energy sources like coal and petroleum. The ability of a renewable fuel to integrate into the existing supply infrastructure would be a major advantage. Although costs are prohibitive today, bioSNG would provide a hedge against volatility in natural gas markets and prepare North America for a future where high energy prices and low-carbon fuels are the standard, not the exception.

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Supporting Information Available

Figures that illustrate the model, system boundaries, and Canada's pipelines are included; more detailed information on land area and biomass resource estimation methods. This information is available free of charge via the Internet at http://pubs.acs.org/.

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