Greenhouse Gas Abatement Costs of Hydrogen Production from Underground Coal Gasification (UCG)

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Highlights

- Estimation of GHG abatement costs for UCG and SMR with and without CCS
- UCG-CCS has the lowest GHG abatement costs
- UCG-CCS has the highest GHG abatement potential
- Life cycle GHG emissions in SMR-CCS are higher than in UCG-CCS

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Abstract

The demand for hydrogen is likely to increase in the next decade to satisfy the projected growth of the bitumen upgrading industry in western Canada. This paper presents greenhouse gas (GHG) abatement costs and the GHG abatement potential in producing hydrogen from underground coal gasification (UCG) along with carbon capture and sequestration (CCS). Seven hydrogen production scenarios are considered to assess the competitiveness of implementing UCG compared to steam methane reforming (SMR). The analysis is completed through a life cycle assessment (LCA) of large-scale hydrogen production from UCG and SMR with and without CCS. Considering SMR technology without CCS as the base case, the GHG abatement costs of implementing the UCG-CCS technology is calculated to be in the range of 41-109 $CAD/tonne-CO2-eq depending on the transportation distance to the CCS site from the UCG-H2 production plant. Life cycle GHG emissions are higher in UCG than in SMR. The GHG abatement costs for SMR-CCS-based scenarios are higher than for UCG-CCS-based scenarios; they range from 87-158 $CAD/tonne-CO2-eq in a similar manner to UCG-CCS. Consideration of revenues for selling the CO2 captured for enhanced oil recovery (EOR) reduces the GHG abatement costs. An opportunity for revenue generation is realized in the UCG-CCS case.

Keywords

Carbon capture and sequestration (CCS); underground coal gasification (UCG); hydrogen (H_2) production; GHG abatement costs; life cycle GHG emissions

Nomenclature

1. Introduction

Bitumen, a highly viscous fluid, must be chemically and physically processed to decrease its viscosity, density, sulphur, carbon, and metal concentrations [1, 2]. This process is called bitumen upgrading, and the product obtained is known as synthetic crude oil (SCO) [1]. Bitumen is upgraded for the following reasons. First, upgraded bitumen can be fed to refineries that are designed to process conventional crude oils [3]. Second, upgraded bitumen does not require a solvent in transportation to refineries [1, 3]. Third, the market price of the bitumen increases when upgraded [1, 3].

SCO production from the Canadian oil sands is expected to increase from 51.1 million m^3 per annum in 2012 to 73.3 million m^3 per annum in 2022 [4]. Due to the greater contribution of Alberta's oil sands industry to the province's total greenhouse gas (GHG) emissions (around 23%) compared to other sectors like electricity generation, heat generation, transportation, etc., there is a growing need for the oil sands industry to adopt cleaner ways of energy production to mitigate GHG emissions [5]. More specifically, bitumen upgrading for SCO production, which requires around 21 kg H_2 per m^3 bitumen, relies mainly on natural gas for H_2 production and has a significant GHG footprint [6, 7]. For instance, the life cycle GHG emissions in H_2 production from SMR are reported to be in the range of 9-14.5 kg-CO_2-eq/kg-H_2 [6, 8-12]. Unarguably, the GHG footprint associated with H_2 production alone, for bitumen upgrading, is significant and alternate fossil-fuel based H_2 production pathways like underground coal gasification need to be explored.

Around 54% of the Alberta's total coal reserves of 1.8-2.7 trillion tonnes, deemed unrecoverable through conventional mining methods, can be recovered through novel technologies like underground coal gasification (UCG) [13]. UCG has several economic and environmental benefits over conventional coal gasification – low ash residues and fugitive emissions, zero coal transport cost and emissions, zero coal handling and coal gasifier costs, etc. [14-17]. In addition, Alberta has the potential to store up to three giga tonnes of CO_2, apart from storing up to 450 mega tonnes (Mt) of CO_2 in enhanced oil recovery (EOR) operations [18, 19]. More specifically, UCG in combination with carbon capture and sequestration (CCS) has the potential to address the current environmental issues of energy production in the Canadian oil sands industry and can also be tied to the Government of Alberta's plan to reduce 139 mega tonnes of GHG emissions through CCS in 2050 compared to GHG emissions level in 2005 [5, 7]. With regard to CCS, over CAD $ 3 billion worth of investments have been made by various provincial governments and Canada's federal government in various CCS demonstration projects [19]. For instance, the Government of Alberta has recently approved a large-scale carbon dioxide (CO_2) pipeline project called the Alberta Carbon Trunk Line (ACTL), which will transport up to 10,000 tonnes per day of CO_2 captured from a refinery and a fertilizer plant located in Fort Saskatchewan to an EOR site in Clive, Alberta [20]. In another large-scale CCS project – Shell Canada's Energy Quest Project – about one million tonnes of CO_2 per annum, captured from a bitumen upgrading facility located in Fort Saskatchewan, Alberta, will be transported and sequestered in a nearby geological site [21].

Arguably, UCG-CCS is a potential candidate for clean carbon conversion and H_2 production, which will aid in the sustainable development of the Canadian oil sands industry. While CCS significantly reduces GHG emissions, there are energy and cost penalties associated with it [19, 22]. The competitiveness of UCG over SMR can be evaluated from both environmental and economic perspectives. Although the UCG and CCS technologies are in the development stages in western Canada, it is important to quantify the environmental footprint and the economic assessment in order to provide key insights for decision making for the government and industry regarding such technologies. GHG abatement cost is one such policy tool used to evaluate GHG mitigation and the economics of an energy system [23, 24]. This metric is useful in determining which technologies have superior GHG abatement potential or greater economic competency [24].

There are many studies in the literature that estimate the GHG abatement potential and GHG abatement costs of energy efficiency technologies and CCS in various industry sectors [22, 24-36]. Saygin et al. [22] concluded that energy efficiency technologies and CCS can help reduce the Netherland’s 1990 industrial GHG emissions by 47%by 2040. In a study by Xiao et al. [24], the authors concluded that 34 energy saving technologies can be implemented at an calculated average GHG abatement costs of US$19.50 (for the year 2010) per tonne-CO_2 in China’s building sector. Garg et al. [26] created marginal abatement cost curves for electricity and CO_2 emissions for Gujarat, India. In a study applicable in South Africa by Telsnig et al. [27], a coal-based integrated gasification combined cycle (IGCC)-CCS plant was found to have the greatest potential for GHG mitigation and the lowest GHG abatement costs among synthetic fuel coal-to-liquid (CTL)-CCS, gas-to-liquid (GTL)-CCS and coal fired ultra-supercritical (USC)-CCS plants.

Levihn et al. [31] developed marginal abatement cost curves for Stockholm district heating system by utilizing a systems approach integrated with a feedback loop to overcome option redundancy.In another study by Zhang et al. [35], the authors estimated energy savings potential of around 5.7 exajoule in 2030 by implementing 56 energy efficiency measures in the Chinese iron and steel industry in China. With a focus to reduce emissions from natural gas flaring in Brazil, Branco et al. [28] calculated GHG abatement costs of installing and operating an offshore GTL plant. Kamel et al. [30] implemented the International Energy Agency Energy Technologies Perspectives model and concluded that CCS can contribute significantly (around 19% of global emissions) in achieving a 50% global emissions reduction target (compared to 2009 level) in 2050. In a recent study by Rootzén et al. [36], the authors analyzed GHG abatement options for petroleum refining, integrated iron and steel production, and cement manufacturing industries in Nordic countries of Denmark, Finland, Norway and Sweden. They concluded that, though an extensive CCS deployment will help achieve the emissions reduction target in 2050, there is likely to be a trade-off in terms of energy use and associated costs. Granovskii et al. [29] evaluated the economic implications of adopting wind and solar technologies for hydrogen production for use in fuel-cell vehicles in Canada. They estimated the GHG abatement costs to be around $US (2007) 0.4 and 1.4 per kg-CO_2 for producing hydrogen from wind and solar energies, respectively. Furthermore, the authors in [33] evaluated the environmental and economic feasibility of hydrogen production from geothermal energy-based electricity in Algeria; the geothermal thermal power plant utilized CO_2 as a heat transmission fluid.

While all the aforementioned studies were not implemented for specific UCG-based H_2 production scenarios in Canada, there is reason to assess the GHG reduction potential and GHG abatement costs of UCG technology along with the consideration of CCS. In other words, none of the studies in the literature have considered UCG-based large-scale H_2 production systems in the oil production sector where there is considerable interest to reduce the overall GHG footprint. The results of this study will help in increased participation of industrial and government stakeholders in formulating policy and making investment decisions for large-scale development of UCG technology. In addition, this study will help in exploring avenues for efficiency improvements in H_2 production processes to minimize the overall GHG emissions and costs of GHG abatement.

The principal objective of this paper is to estimate the GHG abatement costs of H_2 production from fossil-fuel based pathways – SMR and UCG – for a variety of feasible scenarios applicable in western Canada. Of the seven scenarios assessed in this study, five scenarios include the consideration of CCS with the distinctions of (1) type of CO_2 sequestration method, (2) transportation distance or location of CO_2 sequestration from the H_2 production plant, and (3) sale of CO_2 to an EOR operator. The goal of the study is not only to evaluate the GHG emissions reduction potential of novel H_2 production technologies – UCG-CCS and SMR-CCS – but also to provide key insights and strategies to formulate energy policies for reducing the carbon footprint of the bitumen upgrading industry.

This paper uses the results of the techno-economic model developed in an earlier study [7] to estimate the GHG abatement costs for the seven scenarios. The GHG emissions for various scenarios are evaluated using a life cycle assessment (LCA) method. The life cycle GHG emissions for UCG-based H_2 production scenarios are evaluated using the LCA model discussed in [37]. The life cycle GHG emissions for SMR-based scenarios are calculated by using (1) the energy and material inputs of an LCA model as developed earlier in the literature [12] and (2) the earlier developed process model for the SMR process [38]. The key contribution is in development of the emission factors for material and energy use, and data inputs in the SMR-LCA model to represent western Canadian conditions[2]. In addition, the authors estimated the life cycle GHG emissions in H_2 production from SMR along with CCS. Moreover, a sensitivity analysis was completed to identify key input parameters that can substantially change the GHG abatement costs. The GHG abatement costs are in 2014 Canadian dollars. The following section gives a brief description of the H_2 production scenarios developed in this study.

[2] For instance, Spath et al.[12] considered an electricity emissions factor based on the mid-continental United States electricity generation mix, which is not applicable to western Canada, especially Alberta. Ultimately, the GHG emissions associated with electricity use or export will vary. Moreover, existing studies in the literature [8, 10-12] did not evaluate or oversimplify the assumptions while calculating life cycle GHG emissions in H_2 production along with CCS.

1.1 Western Canadian H_2 production scenarios

Table 1 shows the seven H_2 production scenarios that can be implemented in western Canada and are likely to be considered by the bitumen upgrading industry [7]. Figure 1 provides a geographical representation of these seven scenarios and a high-level system boundary. These scenarios are similar to those considered earlier [7] in a techno-economic evaluation of UCG- and SMR-based H_2 production with and without CCS developed for western Canada. Scenarios 1-3 represent SMR-based H_2 production pathways; scenarios 1 and 2 have CCS with the different locations of sequestration (see Table 1). In scenarios 1-3, the H_2 production site is the same as the bitumen upgrading site and is located at Fort Saskatchewan, Alberta. Scenarios 4-7 represent UCG-based H_2 production pathways; scenario 6 is without CCS and the others are with CCS. Again, the discerning feature in the scenarios with CCS is the location of the CO_2 sequestration; in scenario 7, the captured CO_2 is sold to an EOR well operator located in close proximity to the UCG plant at a price of \$47/tonne-CO_2 [7]. The revenues for the sale of CO_2 are calculated based on the incremental flow of CO_2 in the UCG-CCS over the SMR-CCS case [7].

Table 1

Fig. 1

2. Method

2.1. Scope of study

The purpose of this analysis is to estimate the GHG abatement costs in different scenarios of H_2 production in western Canada (see Table 1). The characteristics of the bitumen upgrading plant, UCG-CCS plant, and SMR-CCS plant are listed in Table 2. The GHG abatement costs ($CAD/tonne-$CO_2$-eq) are evaluated using Eq. 1; the value of 'i' indicates the scenario number for which the abatement costs are being calculated, 'ref' is the reference scenario number, the costs of H_2 production are in $CAD/kg-$H_2$, and the life cycle GHG emissions are in kg-CO_2-eq/kg-H_2; the functional unit selected in the LCA is 1 kg of H_2. The choice of the reference scenario has a considerable impact on the GHG abatement costs. The GHG abatement costs are calculated by comparing scenarios with the two H_2 production technologies, i.e., UCG and SMR with and without CCS; the reference technology for calculating the GHG abatement costs for all scenarios is SMR (scenario 3). The system boundaries considered for the H_2 production technologies (UCG, UCG-CCS, SMR, and SMR-CCS) are described in the following section.

Table 2

$$(\text{GHG abatement cost})_i = \left(\frac{(\text{Levelised cost of } H_2 \text{ production})_i - (\text{Levelised cost of } H_2 \text{ production})_{ref}}{(\text{Life cycle GHG emissions})_{ref} - (\text{Life cycle GHG emissions})_i}\right) * 1000 \quad (1)$$

2.2. Economic analysis model: H_2 production from UCG and SMR with and without CCS

H_2 production costs were calculated by developing a data-intensive discounted cash flow model for each scenario. Table 3 shows the key input data and assumptions for H_2 production costs estimation in different scenarios for the discounted cash flow model. The economic data for the UCG-based H_2 production plant was based on the costs specified for an above surface coal gasification plant in [47]. Since the plant infrastructure required for the UCG-based H_2 production plant is similar to the above surface coal gasification plant, this enables to reasonably estimate the plant capital costs associated with the former case. On the other hand, the SMR-based H_2 production plant capital costs were based on a Foster Wheeler plant developed for the International Energy Agency [41]. Since the UCG-based scenarios are characterized with transport of H_2 via pipeline to the bitumen upgrading facility, appropriate sizing and costing of the pipeline infrastructure were completed based on Panhandle B equation and a model in literature by [48], respectively. The capital costs associated with CO_2 compression (upto 150 bar) and pipeline transport were estimated based on the method discussed by authors in [49].

Table 3

2.3.System boundaries and life cycle assessment model

There are different environmental indicators to evaluate the environmental impact of a product or energy production pathway over its life cycle. In this study, global warming potential (GWP) – represented by kg-CO_2-eq/ kg-H_2–is the only impact category of interest. The GWP of other greenhouse gases than CO_2 i.e., CH_4 and nitrous oxide have been considered and converted to the CO_2-eq. There are other environmental issues and challenges (land subsidence, ground water contamination, process control and operational reliability) associated with UCG; however, a holistic evaluation of the environmental externalities associated with this pathway is beyond the mandate of the paper. The research addresses the increased uncertainty and challenges associated with UCG by assigning a risk premium relative to SMR. The differential in the IRR required for both options is reflective of the elevated risk that pertains to UCG (see Table 3). Furthermore, it is important to quantify the economic merits of implementing UCG (along with CCS) as a means to mitigate GHG emissions in the Albertan bitumen upgrading industry. To put in perspective, CCS implementation in large-scale fossil fuel energy systems is the central point of Government of Alberta's strategy to reduce GHG emissions by 200 million tonnes in 2050 compared to emissions level in 2005 [5]. Therefore, the GWP impact is the only category of interest in the present study. The life cycle GHG footprint is, therefore, evaluated for the seven H_2 production scenarios using an LCA approach. The emission factors for material and energy use in different unit operations of the H_2 production pathway are listed in Table 4.

Table 4

2.3.1. H_2 production from SMR with and without CCS (scenarios 1-3)

The life cycle GHG emissions in the SMR process (scenarios 1-3) are evaluated for the system boundary shown in Fig. 2. The boundary start point is the natural gas (NG) input to the hydrogenation and sulphur removal section. It is important to note that the upstream emissions and losses associated with NG production are considered in the analysis. Moreover, NG is used both as a feedstock (for H_2 production) and fuel (SMR fuel burner). High-pressure steam is imported for use in SMR reactor and a series of water-gas shift reactors to produce CO2 and H2 rich gas. Selexol technology is used for CO_2 capture which is compressed upto a pressure of 150 bar before its transport to a sequestration site via a pipeline. A heat exchanger network in the NG-to-H_2 conversion section recovers heat that can be used to produce either steam or electricity. The H_2 produced in the pressure swing adsorption unit (14 bar) is captive in nature, and is stored at a pressure of 70 bar [7] for use in the in-house bitumen upgrading facility. This is the boundary end point.

The key energy and material inputs in SMR-based H_2 production plant operations (see Fig. 2) are derived from the LCA study from literature [12] and the results of an earlier developed process model [38]. In SMR-based H_2 production scenarios with CCS (scenarios 1 and 2), the CO_2 pipeline design for transportation and injection well design for sequestration are derived from the method developed by Ogden [52]. The emissions related to pipeline construction and sequestration (the use of steel in pipelines and diesel in trenching and well drilling) are then evaluated using the method and assumptions incorporated in the LCA model – FUNNEL-GHG-H2-UCG (**FUN**damental E**N**gineering Princip**lE**s-based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in hydrogen (**H2**) production from **U**nderground **C**oal **G**asification) – discussed in [37]. The electricity requirement for H_2 compression from 14 bar to 70 bar is estimated using Panhandle B equation [52].

An SMR-based H_2 production pathway can be self-sufficient in terms of electricity or steam use depending on the final use of the heat recovered by the heat exchangers in the NG-to-H_2 conversion section (see Fig. 2); the ”electricity co-production” scenario represents the former case and “steam co-production” scenario represents the latter. Appropriate credits are given for the export of electricity and steam. In "electricity co-production" scenario, the total electricity production is calculated based on electricity produced by a natural gas turbine with a thermal efficiency of 36.1% [53]; the NG input is calculated based on equivalent amount of NG required to produce steam (here, refers to the excess steam produced in H2 production) in a boiler with an efficiency of 75% [12]. In case there is additional electricity production (after considering the electricity requirements of various unit operations, and a transmission loss of 6.5% in export of electricity to the grid [6]), a credit of 0.65 kg-CO_2-eq/kWh (applicable for Alberta, see Table 4) is awarded. On the other hand, in "steam co-production" scenario, the emissions credit is estimated based on offsetting use of equivalent amount of NG (i.e., emissions associated with NG use, recovery, processing, transmission and distribution, see Table 4) for excess steam production (after considering the steam requirements in various unit operations) in a boiler with an efficiency of 75% [12].

2.3.2. H_2 production from UCG with and without CCS (scenarios 4-7)

The life cycle GHG emissions in UCG-based H_2 production scenarios (scenarios 4-7) are evaluated using the assumptions and inputs to the FUNNEL-GHG-H2-UCG [37]; the system boundary for UCG-based H_2 production scenarios is depicted in Fig. 3. FUNNEL-GHG-H2-UCG uses a process modelling approach to estimate the operation emissions in H_2 production from UCG with and without CCS [37]. The boundary start point is the injection of gasifying agents (O_2 and H_2O), The syngas is collected from the UCG production wells and fed to a surface syngas-to-H_2 production plant; this plant is assumed to be located near the UCG wells and any energy inputs in transporting or storing syngas are neglected. The produced syngas is converted to H_2 using conventional technologies utilized in above surface coal gasification-based H_2 production pathways. Selexol technology is used for CO_2 capture. Furthermore, pipeline is used to transport H_2 from the UCG site to the bitumen upgrader, which is the boundary terminating point. It is important to mention that a combined cycle configuration was modelled to utilize the purge gas (produced in the H_2 separation process in the pressure swing adsorption unit) for electricity and steam production. Importantly, the electricity requirement in different unit operations (see Fig. 3) is offset by electricity production in the on-site co-generation plant, and a syngas expander placed after UCG. Any additional electricity produced is exported to the grid outside the system boundary, and appropriate emissions credit is awarded (around 0.65 kg-CO_2-eq/kWh, see Table 4). Moreover, this pathway is self-sufficient in terms of steam use.

It is worth noting that the key differentiating feature in the FUNNEL-GHG-H2-UCG discussed in [37] and the present study is the scale of the H_2 production. The former study considered small scale H2 production of around 118 tonnes/day, whereas this study evaluates the GHG foot-print of a large scale UCG-based H_2 production (828.2 tonnes/day). This is done by making appropriate changes with regards to sizing of the equipments like multiple UCG well pairs, CO_2 compressors, pipeline transport and sequestration, and H_2 pipeline transport. Base case assumptions of an H_2O-to-O_2 injection ratio of 2, steam-to-carbon ratio of 3 and a ground water influx of 0.4 m^3/tonne-coal are considered in this paper [37].

Fig. 2

Fig. 3

3. Results and Discussion

The GHG abatement costs are a function of the life cycle GHG emissions for a given scenario (see Eq. 1). Therefore, it is important to quantify the life cycle GHG emissions for energy and material inputs in different unit operations over the life cycle of the operation. As mentioned earlier, the life cycle GHG emissions are reported in kg-CO_2eq/kg-H_2.

3.1. Life cycle GHG emissions in SMR-based H_2 production scenarios

Table 5 lists the life cycle GHG emissions from scenarios 1, 2, and 3 for the system boundary presented in Fig. 2. It is important to reiterate that the H_2 production capacity in these scenarios is 607 tonnes per day (see Table 2). Moreover, for each of these scenarios, there are two sub-scenarios or plant schemes considered in this analysis – steam co-production and electricity co-production (see Fig. 2). In both plant schemes, the emissions associated with all energy and material uses are the same, except electricity use, steam use, electricity export, and steam export. While there are no emissions associated with the electricity use and there is no emissions credit for the steam export from the plant scheme with electricity co-production, these emissions are considered in the plant scheme with steam co-production. However, the emissions associated with the steam use and the electricity export in the steam co-production plant scheme are considered.

The advantage of electricity co-production over steam co-production in the SMR-based H_2 production pathway is clearly evident in terms of the total life cycle GHG emissions (see Table 5); in the former scenario, the excess steam produced from the heat recovered in the syngas-to-H_2 conversion section is used to produce electricity from a steam turbine. This is mainly because producing electricity from the excess steam not only offsets the grid electricity use, but also results in electricity export to the grid. This advantage is complemented by the fact that the emission factor for electricity use (244.4 gm-CO_2-eq/MJ-electricity [51])[3] and the emissions credit for electricity export to the grid (180.6 gm-CO_2-eq/MJ-electricity [51]) in Alberta is greater than NG use (61.3 gm-CO_2-eq/MJ-NG [6]). Moreover, replacing coal with other, cleaner fuels like natural gas or even renewable energy production methods like hydro, wind, etc., for electricity production would result in lower GHG emissions.

It is also evident from Table 5 that the CCS technology results in a significant reduction in the amount of GHG emissions in scenarios 1 and 2 compared to 3. The total life cycle GHG emissions in scenario 2 are slightly greater than in scenario 1. This is mainly due to the lower contribution of CO_2 construction emissions (steel and diesel use in pipeline construction and trenching, respectively) in the total life cycle GHG emissions. It is interesting to note that in spite

[3] A relatively high electricity emission factor is attributed to the use of coal for electricity production in Alberta, Canada.

of a 91.6% CO_2 capture (see Table 2) using Selexol solvent in a pre-combustion plant configuration, the total life cycle GHG emissions decrease only by around 44% (see Table 5). This is mainly because there is an energy penalty in terms of increased electricity use to deploy CCS in this H_2 production pathway. Moreover, the GHG emissions associated with this increased use of electricity partially offset the advantage of CO_2 capture in the total life cycle GHG emissions calculation. In addition, post CO_2 capture, the purge gas contains significant amounts of CH_4 (around 33.6% by mol) [38], which results in GHG emissions on combustion in the burner (see Fig. 2).

Table 5

3.2. Life cycle GHG emissions in UCG-based H_2 production scenarios

The life cycle GHG emissions for scenarios 4, 5, 6, and 7 are listed in Table 6. As mentioned earlier, the results for the respective scenarios are based on the FUNNEL-GHG-H2-UCG [37], with the difference being the scale of H_2 production considered in the present analysis. Moreover, the H_2 production capacity in these scenarios is 660 tonnes per day as compared to a H_2 production capacity of 607 tonnes per day in SMR-based H_2 production scenarios (see Table 2). Because the H_2 production scales in the two pathways (SMR and UCG) are similar, the scenarios can be reasonably compared with each other. It is important to mention that the life cycle GHG emissions in the present analysis are slightly greater than the results presented in [37], mainly due to the increased scale of H_2 pipeline transport from the UCG plant to the bitumen upgrading facility. A larger scale of H_2 pipeline operation results in more electricity consumption at the inlet pump station compared to a lower scale of pipeline operation; electricity consumption increases to account for increased friction losses in the pipeline. . This rise in electricity consumption lowers the emissions credit for electricity export to the grid and ultimately the total life cycle GHG emissions increase.

Table 6

3.3. GHG abatement costs in H_2 production scenarios

The GHG abatement costs for the seven scenarios listed in Table 1 are estimated using Eq. 1, and include the additional cost of using a technology per unit savings in the life cycle GHG emissions. Table 7 lists the GHG abatement costs calculated for various H_2 production scenarios. The reference scenario chosen for the analysis is scenario 3, which uses an SMR-based H_2 production technology without CCS. As mentioned in section 2.2, two plant configurations – electricity co-production and steam co-production – are chosen for the analysis of SMR-based scenarios. The GHG abatement costs are negative and hence lowest for scenario 7; they range from -$ 12.91 CAD to -$ 13.27 CAD per tonne-CO_2-eq. This observation can be explained by the lower costs of H_2 production in scenario 7 than in scenario 3. It is important to reiterate that the sale of captured CO_2 to an EOR operator (at $47/tonne-$CO_2$) not only negates the additional cost of CCS but also lowers the levelised cost of H_2 production in scenario 7 [7]. Another important observation is that in spite of higher levelised cost of H_2

production, the GHG abatement costs in all the UCG-CCS-based scenarios (scenarios 4, 5, and 7) are lower than those in the SMR-CCS-based scenarios (scenario 1 and 2). This is attributable to higher life cycle GHG emissions in the SMR-CCS scenarios than in the UCG-CCS scenarios[4,5].

It is important to note that despite different plant configurations and equipment, there is no significant difference in the levelised cost of H_2 production in scenarios 3 (SMR without CCS) and 6 (UCG without CCS). This is mainly because the incremental levelised cost of H_2 production due to the higher total capital costs in the UCG-based H_2 production plant than the SMR-based H_2 production plant is compensated by the negligible feedstock cost of coal in the former case versus a feedstock cost of $5/GJ-NG in the latter case. That being said, the costs of GHG emissions mitigation in SMR-CCS and UCG-CCS-based scenarios are mainly due to the capital costs of the additional infrastructure required for CCS – CO_2 capture equipment, CO_2 compressors, CO_2 pipeline, and CO_2 sequestration costs. Moreover, for a fixed H_2 production scale in SMR- and UCG-based scenarios, the GHG abatement costs are highly sensitive to the transportation distance of the captured CO_2 to the sequestration site; with an increase in

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[4] In a pre-combustion carbon capture scheme, as considered in the present LCA analysis of SMR-based H_2 production, a significant amount of natural gas that is not converted to H_2 in the reformer is burned in the burners as purge gas (see section 3.1 and Fig. 2). On the other hand, in UCG-CCS, around 90% of the carbon in coal is converted to CO_2 after UCG and syngas-to-H_2 conversion (see Fig. 3), leading to high CO_2 capture efficiency as compared in the SMR-CCS pathway.

[5] Note that the CO_2 capture rate in a UCG-CCS plant is higher than in a SMR-CCS plant (see Table 2) resulting in increased capital costs of CO_2 capture, compression and transport in the former case than in the latter. This leads to higher levelised H_2 production costs in the UCG-CCS than in the SMR-CCS (see results for scenario 2 and 5 in Table 6).

transportation distance from 84 km (scenario 1) to 225 km (scenario 2), the GHG abatement costs rise by around 71%.

Table 7

3.4. Comparison of GHG abatement costs with other studies

To the knowledge of the authors, there is no study in the literature that discusses GHG abatements for H_2 production from UCG along with the consideration of CCS. That said, some studies evaluated these costs for replacing natural gas as a feedstock for H_2 production with alternate pathways based on solar, wind, advanced coal gasification (CG) with CCS and advanced auto thermal reforming (ATR) with CCS [29, 46]. These studies were completed for the Canadian and Dutch transportation sector. While both studies evaluated the GHG abatement costs for replacing gasoline-powered vehicles with H_2-based fuel cell vehicles, the study [46] also considered various end-user markets (combined heat and power, residential and steel industry) for H_2 production from SMR and coal gasification along with CCS. Table 8 summarizes the key differences in the H_2 production costs estimates, GHG emissions and GHG abatement costs for different pathways. The GHG abatement costs are based on SMR as the reference H_2 production system, and vary in different jurisdictions, even for a similar pathway. This is mainly attributed to the fact that the assumptions for calculating H_2 production costs and GHG emissions differ in the studies.

Table 8

3.5. Sensitivity analysis

A sensitivity analysis was conducted to appreciate the effect of various input parameters on the GHG abatement costs. In order to understand their effect on the overall results, a variation of ±36% in the input parameters was completed. Figure 4 shows the sensitivity analysis completed for scenarios 1 and 4. For scenario 1, the NG price ($5/GJ as the base case value) is found to have no sensitivity towards the GHG abatement costs. Though the levelised H_2 production costs increase with rise in the NG price in scenarios 1 and 3 (base case scenario), the difference in these costs remains the same. Hence, the GHG abatement costs are not affected. However, for scenario 4, the NG price has strong sensitivity towards the GHG abatement costs. The GHG abatement costs decrease from $CAD 42 to 10.3 per tonne-CO_2-eq abated. Quite intuitively, for both scenarios, the H_2 plant capital costs and IRR have high sensitivity towards the GHG abatement costs; GHG abatement costs surge with a increase in the values of these input parameters, and vice versa. That said, for scenarios 4, the GHG abatement costs become zero for an IRR of around 11.5% and 7.6% in scenarios 4 and 1, respectively; the H2 production costs for scenarios 4 and 3 become equivalent. With regards to the impact of installation factor (base value of 1.65), it is moderate and low for scenarios 1 and 4, respectively. This is mainly due to the fact that the percentage change in the H_2 production costs in scenario 1 is greater than in scenario 4 with respect to the base scenario 3 upon equivalent change in the installation factor value.

Fig. 4

3.6. GHG mitigation potential of UCG-CCS and SMR-CCS technologies for H_2 production

Figure 5 shows the GHG mitigation potential of H_2 production scenarios with CCS in 2022. The GHG mitigation potential is estimated for SMR-CCS and UCG-CCS technologies for H_2 production in order to satisfy the projected SCO production of 73.53 million m^3 per annum in 2022 [4]. The base scenario for the analysis is scenario 3. Moreover, based on the type of SCO production pathway, i.e., upgrading of in-situ or surface-mined bitumen[6], the lower limits and the upper limits for emissions mitigation in each scenario are assessed. Based on the present analysis, the GHG abatement potential is highest for UCG-CCS-based H_2 production scenarios and varies from 8.58 to 22.55 Mt of GHG emissions per year. This abatement potential can contribute significantly to the Government of Alberta's plan to reduce GHG emissions by around 50 Mt per year in 2020 [5]. The GHG abatement potential is lower if one of the SMR-CCS-based scenarios (scenario 1 or 2) is adopted for H_2 production; the potential varies from 4.22 to 11.30

[6] The H_2 requirement in upgrading of bitumen in coking-based and hydroconversion-based configurations is estimated to be around 11.7 and 30.3 kg/m^3-bitumen, respectively [6]

Mt of GHG emissions per year. This is mainly attributable to higher life cycle GHG emissions in scenarios 1 and 2 than in scenarios 4, 5, and 7.

Fig. 5

4. Conclusions

This paper provides insight on the GHG abatement costs of replacing SMR technology with SMR-CCS and UCG-CCS technologies for H_2 production for bitumen upgrading in Alberta's oil sands. Seven scenarios were developed and assessed in this study with the distinctions of novel H_2 production technologies (UCG and SMR with and without CCS), type of CO_2 sequestration method, transportation distance or location of CO_2 sequestration from the H_2 production plant, and sale of CO_2 to an EOR operator. The GHG emissions for various scenarios were evaluated using a life cycle assessment (LCA) method and a process modelling approach based on fundamental engineering principles.

A number of valuable conclusions can be drawn from this analysis. First, the life cycle GHG emissions in a large-scale SMR-CCS-based H_2 production (6.024-6.758 kg-CO_2-eq/kg-H_2) are higher than in a large-scale UCG-CCS-based H_2 production (1.255-1.404 kg-CO_2-eq/kg-H_2). However, the life cycle GHG emissions in H_2 production without CCS from SMR (calculated as 11.237 kg-CO_2-eq/kg-H_2) are lower than in H_2 production from UCG without CCS (11.258 kg-

CO_2-eq/kg-H_2). Second, the application of the CCS technology in a UCG-based pathway is more beneficial, both with regard to GHG abatement costs and potential, than in an SMR-based pathway. The GHG abatement costs are calculated to be 40.87-42.03 and 105.86-108.90 \$CAD/tonne-CO_2-eq for UCG-CCS-based scenarios. For SMR-CCS-based scenarios the costs vary from 86.83-91.83 and 148.79-157.67 \$CAD/ tonne-CO_2-eq. However, CCS could play a major role in reducing the GHG emissions in the bitumen upgrading industry.

Third, sale of incremental flows of captured CO_2 for EOR operations in a UCG-CCS-based scenario (scenario 7) compared to the SMR-CCS alternative has the maximum advantage, and an opportunity for revenue generation is recognized. Fourth, for a fixed H_2 production scale, the GHG abatement costs are highly sensitive to the transportation distance of the captured CO_2 to a sequestration site. Finally, large-scale H_2 production from UCG-CCS for SCO production can help reduce Alberta's annual GHG emissions by 22.6 mega tonnes in 2022.

Acknowledgments

We thank the NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair Program in Energy and Environmental Systems Engineering and the Cenovus Energy Endowed Chair Program in Environmental Engineering for their financial support for the research. The authors also acknowledge Astrid Blodgett for editorial assistance in this paper.

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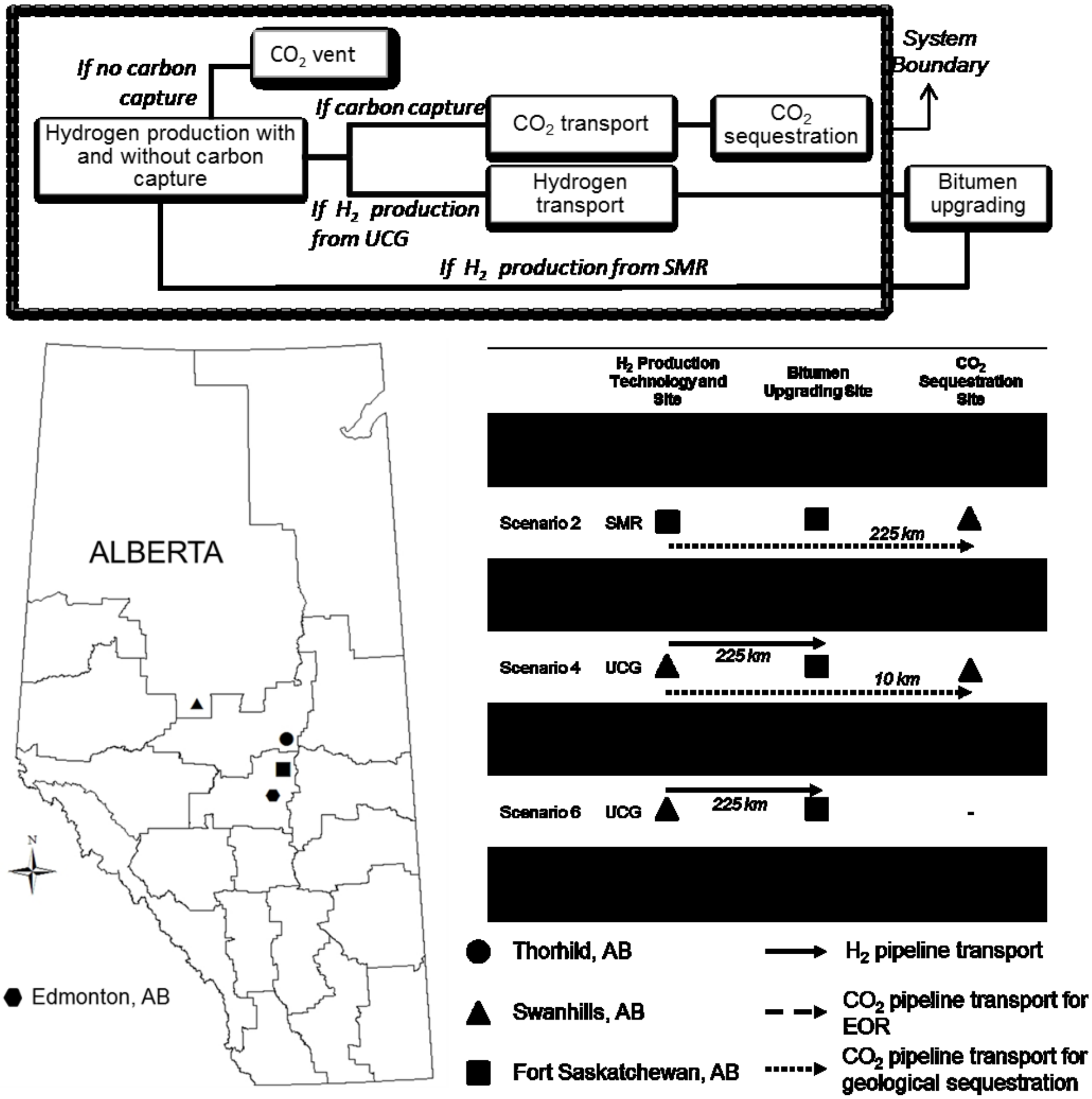


Fig. 1: Geographical representation of the H_2 production scenarios in Alberta

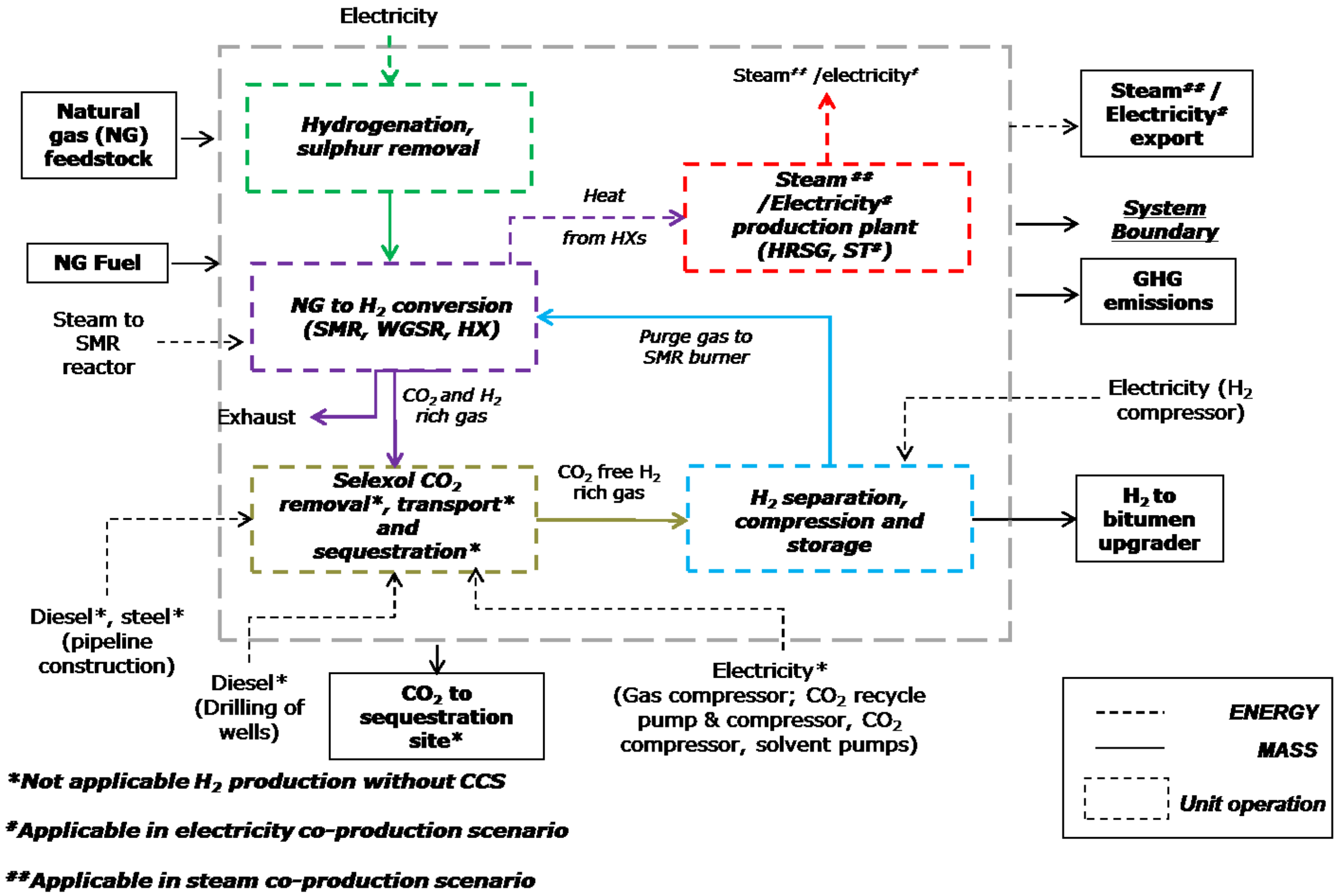


Fig. 2: System boundary for SMR based-H_2 production scenarios. Note: SMR=steam methane reforming; WGSR=water gas shift reactor; HX=heat exchanger; PSA=pressure swing adsorption; HRSG=heat recovery steam generator; ST=steam turbine.

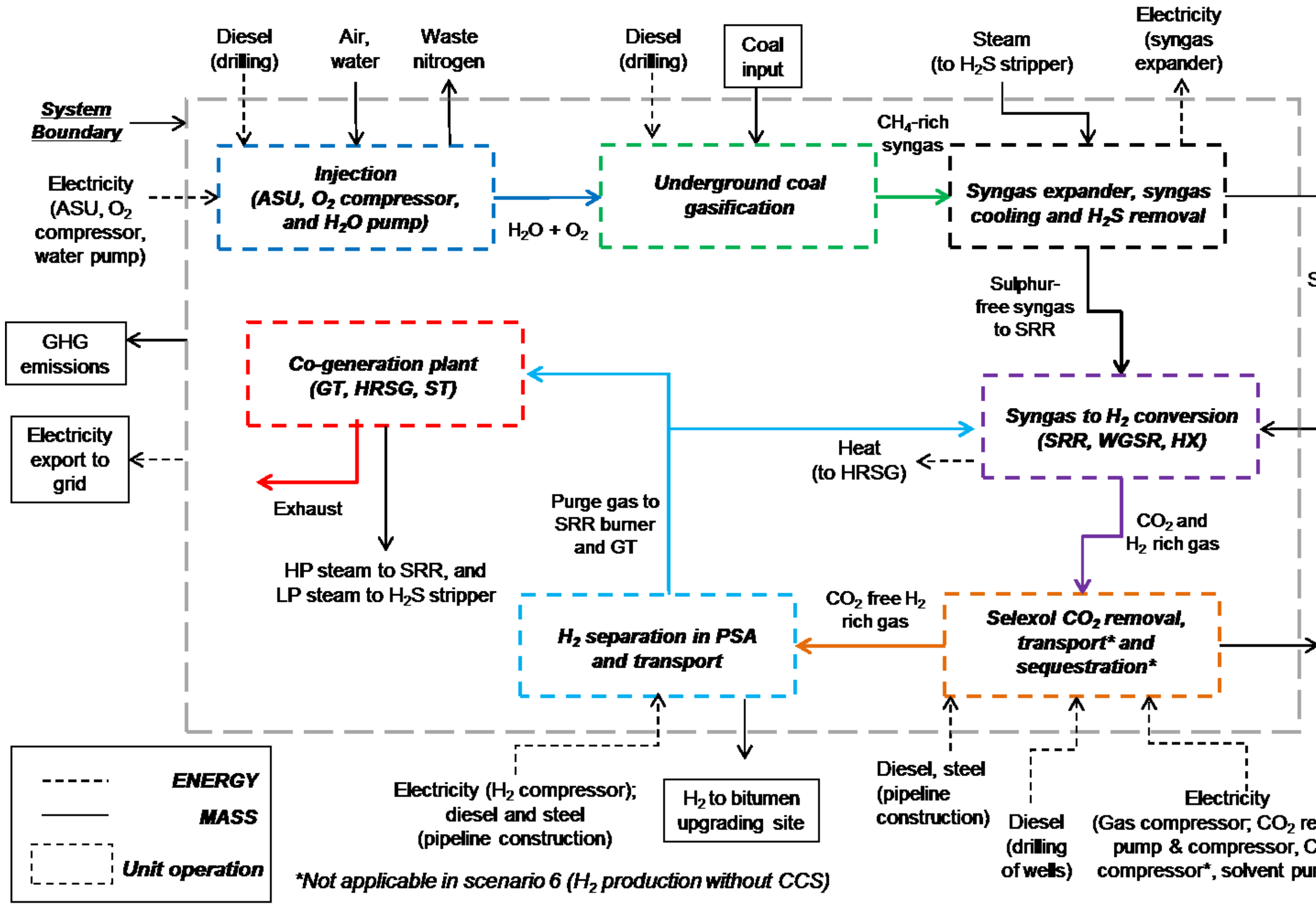
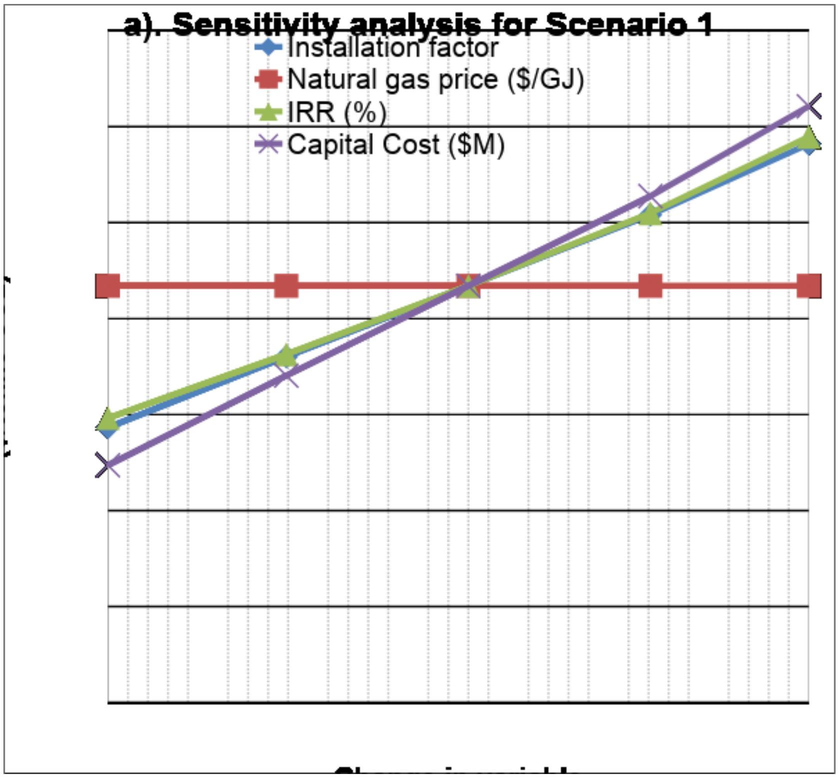


Fig. 3: System boundary for UCG based-H_2 production scenarios. Note: ASU=air separation unit; SRR=syngas reforming reactor; WGSR=water gas shift reactor; HX=heat exchanger; PSA=pressure swing adsorption; HRSG=heat recovery steam generator; ST=steam turbine; GT=gas turbine.


a). Sensitivity analysis for Scenario 1
Installation factor
Natural gas price ($/GJ)
IRR (%)
Capital Cost ($M)

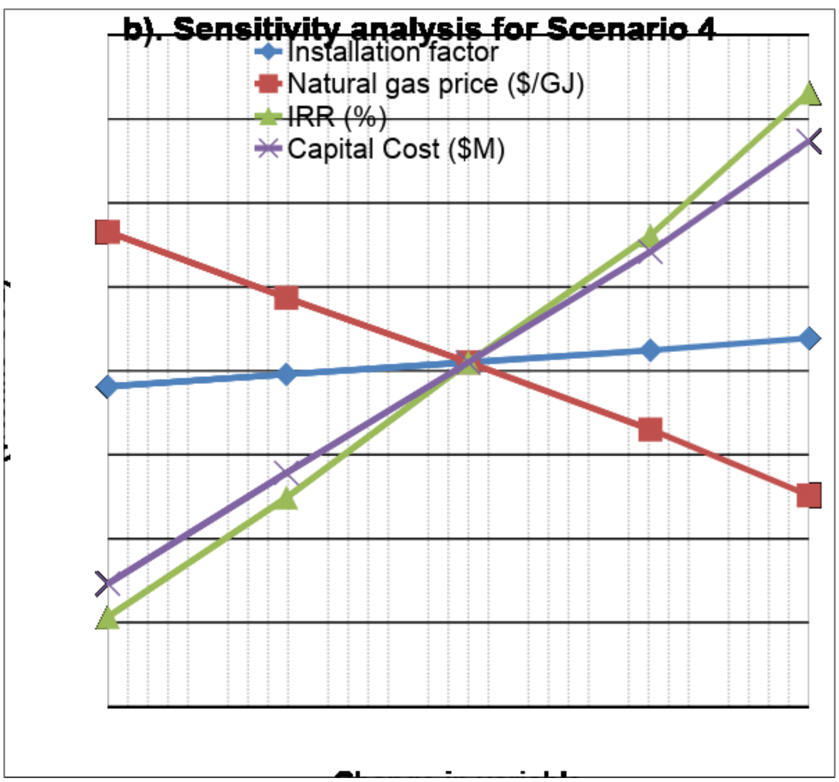

b). Sensitivity analysis for Scenario 4
Installation factor
Natural gas price ($/GJ)
IRR (%)
Capital Cost ($M)

Fig. 4: Sensitivity analysis for GHG abatement costs in scenarios 1 and 4. Note: reference scenario for GHG abatement costs calculation is scenario 3 with electricity co-production.

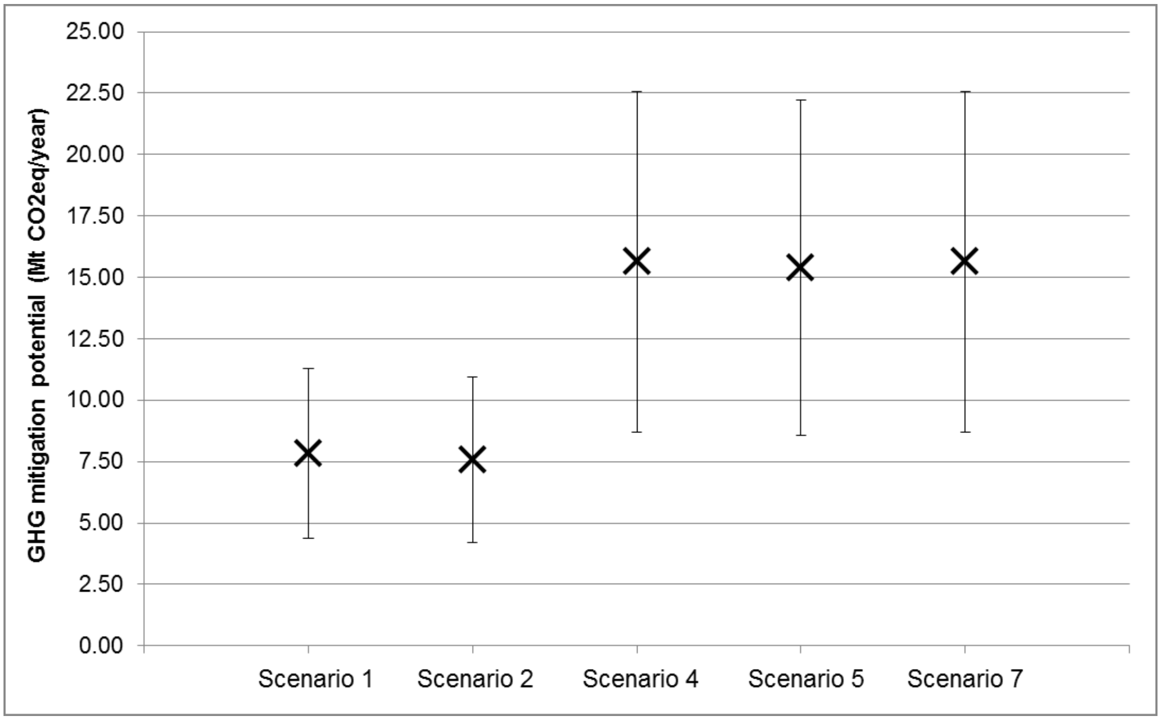


Fig. 5: GHG mitigation potential of replacing SMR technology with SMR-CCS and UCG-CCS technologies for H_2 production in bitumen upgrading in western Canada. The upper limit corresponds to 100% SCO production (projected in 2022) by employing a hydroconversion-based bitumen upgrading configuration, whereas the lower limit corresponds to SCO production in a coking-based bitumen upgrader.

Nomenclature

ACTL	Alberta Carbon Trunk Line
ASU	air separation unit
CCS	carbon capture and sequestration
CO_2-eq	carbon dioxide equivalent
CTL	coal to liquid
EOR	enhanced oil recovery
GHG	greenhouse gas
GREET	Greenhouse Gases, Regulated Emissions and Energy Use in Transportation
GT	gas turbine
GTL	gas to liquid
GWP	global warming potential
HRSG	heat recovery steam generator
HX	heat exchanger
IGCC	integrated gasification combined cycle
kWh	kilowatt hour
LCA	life cycle assessment
MDEA	methyl diethanolamine
MEA	monoethanolamine
MJ	megajoule
Mt	mega tonne
NG	natural gas
PSA	pressure swing adsorption
SCO	synthetic crude oil

SMR	steam methane reforming
SRR	syngas reforming reactor
ST	steam turbine
UCG	underground coal gasification
USC	ultra supercritical
WGSR	water gas shift reactor

Table 1: H_2 production scenarios from UCG and SMR in western Canada (Adapted from [7])

Scenario number	Pathway	H_2 supply chain			CO_2 supply chain	
		Production site	**Delivery site**	**Transportation distance and mode**	**With or Without CCS, and sequestration type**	**Delivery site**
Scenario 1	SMR	Fort Saskatchewan, Alberta	Fort Saskatchewan, Alberta	-	With CCS – geological sequestration	Shell Quest; Thorhild, Alberta
Scenario 2	SMR	Fort Saskatchewan, Alberta	Fort Saskatchewan, Alberta	-	With CCS – geological sequestration	Swan Hills, Alberta
Scenario 3	SMR	Fort Saskatchewan, Alberta	Fort Saskatchewan, Alberta	-	Without CCS	-
Scenario 4	UCG	Swan Hills, Alberta	Fort Saskatchewan, Alberta	225 km via pipeline	With CCS – geological sequestration	Swan Hills, Alberta
Scenario 5	UCG	Swan Hills, Alberta	Fort Saskatchewan, Alberta	225 km via pipeline	With CCS – geological sequestration	Shell Quest; Thorhild, Alberta
Scenario 6	UCG	Swan Hills, Alberta	Fort Saskatchewan, Alberta	225 km via pipeline	Without CCS	-
Scenario 7	UCG	Swan Hills, Alberta	Fort Saskatchewan, Alberta	225 km via pipeline	With CCS – EOR	Swan Hills, Alberta

Table 2: UCG-CCS and SMR-CCS plant specifications

ameter	Value	Sources/ comments
umen upgrader		
pacity, bitumen-barrels/day	290,000	Based on Shell Canada's planned upgrader capacity [7].
requirement in upgrading, kg/m^3-bitumen	21	Based on an average value of 11.7 kg-H_2/m^3 in coking-based bitum upgrading configuration and 30.3 kg H_2/m^3 in hydroconversion-base bitumen upgrading configuration [6]
demand, tonnes/day	828.2	[7]
G-CCS plant		
production capacity, tonnes/day	660	[7]
al consumption, tonnes/day	4784.28	Based on a coal-to-hydrogen conversion efficiency of 58.1% (LHV basis) [39] and coal calorific value of 28.5 MJ/kg [7, 40].
pacity factor	85%	[41]
mber of well pairs required	70	Based on coal thickness (7.5 m), width (80 m), and length (1400 m) a coal seam gasified in a pilot scale project by Swan Hills Synfuels Alberta; a coal utilization factor of 50% is employed [42, 43]. The co bulk density and well lifetime are assumed to be 1.205 gm/cm^3 [42] and 20 years [44], respectively.
al CO_2 captured, tonnes/day	8540.06[1]	Based on the results of FUNNEL-EGY-H2-UCG (**FUN**damental E**N**gineering Princip**lE**s-based Mode**L** for Estimation of **E**ner**GY** consumption and production in hydrogen (**H2**) productio **U**nderground **C**oal **G**asification) developed in [39]; Selexol technolo is employed for CO_2 capture [39].
R-CCS plant		
production capacity, tonnes/day	607	[41]

pacity factor	90%	[41]
ural gas (NG) consumption (fuel and dstock), tonnes/day	1762.26[2]	Based on energy consumption of NG feedstock and fuel equivalent 137 MJ/kg-H_2 and 15 MJ/kg-H_2, respectively [12]. The lower heating value (LHV) of NG and H_2 is taken as 47.14 and 120 MJ/kg, respectively [6].
al CO_2 captured, tonnes/day	3235.57[2]	Calculated based on the CO_2 content of the H_2-rich gas fed to the P unit [38] and a CO_2 capture efficiency of 91.6% achieved by using Selexol technology [39, 45, 46]. While other traditional technologies (i.e., MEA and MDEA) can be applied for CO_2 capture in H_2 product from SMR [46], the Selexol technology is purposefully chosen for benchmarking SMR-CCS with the UCG-CCS-based H_2 production technology.

[1] Capacity factor of 85% is applied to estimate this value. Around 15.22 kg-CO_2 is captured per kg of H_2 produced [39].

[2] Capacity factor of 90% is applied to estimate this value.

Table 3: Key input economic data and assumptions in H_2 production costs estimation in different scenarios

Parameter	Value				Sources and comments
	SMR	**SMR-CCS**	**UCG**	**UCG-CCS**	
Financial year	2014	2014	2014	2014	
Inflation rate	2.5%	2.5%	2.5%	2.5%	[7]
Installation factor	1.65	1.65	1.65	1.65	A higher installation factor harsh climatic conditions a in Alberta [7]
Internal rate of return (IRR)	10%	10%	15%	15%	A higher IRR is chosen for owing to technological infa risk factors (land subsidenc contamination, etc.) and re to syngas production in UC
Plant life, years	25	25	40	40	[7, 41]
Natural gas price, $CAD/GJ	5	5	-	-	[7]
Coal feedstock cost, $CAD/tonne	-	-	0	0	UCG process negates coal transportation costs of the is deemed unrecoverable b mining methods
Electricity cost, $CAD/kWh	0.07	0.07	0.07	0.07	Based on average cost of e [50]
Annual labour costs, $CAD millions/annum	1.7	1.7	1.7	1.7	Based on 8 plant operators shift of 8 hours each [7, 41]

Supervision and administration costs, $CAD millions/annum	1.3	1.3	1.3	1.3	Estimated by considering it labour costs [7, 41]
Total capital costs, $CAD millions	1173[1]	1404[2]	1542[3]	1732[4]	[7]. See foot notes below
Plant equipment operation and maintenance costs	4%	4%	4%	4%	[25]. Expressed as a perce costs

[1] Aggregate capital costs of key plant equipments (reformer, pressure swing adsorption unit, reactors, steam generators, gas turbine, catalysts, H_2 storage (70 bar) and compressors) in an SMR-based H_2 production plant. These also include project contingency costs and associated costs of instrumentation, electrics and piping.

[2] Aggregate capital costs of key equipments (listed above), and CO_2 pump and compressors, pipeline (84 km) and sequestration

[3] Aggregate capital costs of key plant equipments (drilling of UCG wells, air separation unit, O_2 compressors, reactors, pressure swing adsorption unit, gas turbine reactors, steam generators, steam turbine, sulphur recovery unit, H_2S and CO_2 absorber and strippers, H_2 pipeline) in a UCG-based H_2 production plant. These also include project contingency costs and associated costs of instrumentation, electrics and piping. These also include project contingency costs and associated costs of general facilities, balance of plant, engineering, etc..

[4] Aggregate capital costs of key equipments (listed above), and CO_2 pump and compressors, pipeline (10 km) and sequestration

Table 4: Emission factors used in this study

Parameter	Value	Sources/comments
Electricity use, kg-CO_2-eq/kWh	0.88	Applicable for Alberta [51]
Electricity export, kg-CO_2-eq/kWh	0.65	Applicable for Alberta [51]
NG use, gm-CO_2-eq/MJ-NG	56.24	[6]
NG recovery, processing, transmission and distribution, gm-CO_2-eq/MJ-NG	5.12	[6]
Steam export, gm-CO_2-eq/MJ-steam export	81.79	Calculated based on the NG use in a boiler to produce an equivalent amount of steam energy; a boiler efficiency of 75% is assumed [12].
Steel use, kg-CO_2-eq/kg-steel	4.97	[6]
Diesel use, gm-CO_2-eq/MJ-diesel	73.96	[6]

Table 5: Life cycle GHG emissions in H_2 production from SMR with and without CCS (scenarios 1, 2 and 3)

Parameter	With steam co-production ($kg-CO_2eq/kg-H_2$)			With electricity co-production ($kg-CO_2eq/kg-H_2$)		
Applicable scenarios	**1**	**2**	**3**	**1**	**2**	**3**
H_2 production						
Losses in the NG production[1]	1.129	1.129	1.129	1.129	1.129	1.129
Electricity use	1.908[3]	1.908[3]	0.990[2]	0	0	0
NG fuel use and upstream emissions	0.922	0.922	0.922	0.922	0.922	0.922
NG feedstock upstream emissions	0.700	0.700	0.700	0.700	0.700	0.700
Emissions from purge gas combustion[4]	2.981	2.981	8.904	2.981	2.981	8.904
Steam use	0	0	0	2.723	2.723	2.723
Steam export	-1.168	-1.168	-1.168	0	0	0
Electricity export[5]	0	0	0	-2.549	-2.549	-3.182
Construction and decommissioning of H_2 production plant[6]	0.041	0.041	0.041	0.041	0.041	0.041
CCS						
CO_2 pipeline infrastructure, well drilling and leakage	0.077	0.244	-	0.077	0.244	-

Total life cycle GHG emissions	6.590	6.757	11.518	6.024	6.191	11.237

[1] Assumed to be 1.4% of NG production [12]. A global warming potential (GWP) of 25 is taken for CH_4 to calculate GHG emissions [6].

[2] The H_2 is delivered at a pressure of 14 bar and compressed to 70 bar for storage [7]. The value in the table is inclusive of electricity use in compression of H_2 from 14 bar to 70 bar; the power requirement is calculated using a model developed by Ogden [52].

[3] The value includes electricity use in H_2 compression from 14 bar to 70 bar and CO_2 capture using Selexol technology and compression in a five-stage compression train up to 150 bar. Electricity use in CO_2 capture and compression is taken as 203.8 kWh/tonne-CO_2 [39].

[4] Calculated based on a purge gas composition (mol %) – CO-0.3%, CO_2-49.4%, H_2-29.7%, H_2O-1.1%, CH_4-18.4%, N_2-1.1% in scenario 3 [38]; PSA efficiency for H_2 separation is reported in a range of 82-90% [38, 54]. It is assumed to be 85%, which is also consistent with UCG-based H_2 production scenarios [39] and appropriate for benchmarking purpose.

[5] Estimated based on electricity production by a gas turbine with a thermal efficiency of 36.1% [53]; the NG input is calculated based on equivalent amount of NG required to produce steam that would otherwise be exported in a boiler with an efficiency of 75% [12]. Moreover, the value includes the electricity requirement in the H_2 plant operation and a transmission loss of 6.5% in export of electricity to the grid [6].

[6] The difference in this value is negligible for H_2 production with and without carbon capture [55]; a value of 0.041 kg-CO_2eq/kg-H_2 [12] is, therefore, used for both cases.

Table 6: Life cycle GHG emissions in H_2 production from UCG with and without CCS (scenarios 4, 5, 6 and 7)

Parameter	**Life cycle GHG emissions (kg-CO_2eq/kg-H_2)**			
Applicable scenarios	**4**	**5**	**6**	**7**
UCG well drilling	0.003	0.003	0.003	0.003
H_2 production and transport				
Purge gas combustion and venting of gases from CO_2 removal section	1.521	1.521	19.519	1.521
Steam use	0	0	0	0
Electricity use	0	0	0	0
Electricity export	-0.341	-0.458	-1.318	-0.341
H_2 pipeline construction	0.015	0.015	0.015	0.015
Construction and decommissioning of H_2 production plant	0.048	0.048	0.040	0.048
CCS				
CO_2 pipeline infrastructure, well drilling and leakage	0.010	0.275	0	0.010
Total life cycle GHG emissions	1.255	1.404	18.258	1.255

Table 7: GHG abatement costs in H_2 production scenarios. Note: the reference scenario for GHG abatement costs calculation is scenario 3

Scenario number	**H_2 production cost ($CAD/kg-$H_2$)[3]**	**Life cycle GHG emissions (kg-CO_2-eq/kg-H_2)**		**GHG abatement costs ($CAD/tonne-$CO_2$-eq)**	
		Lower limit[1]	***Upper limit[2]***	***Lower limit[1]***	***Upper limit[2]***
Scenario 1	2.36	6.024	6.590	86.83	91.83
Scenario 2	2.66	6.192	6.758	148.79	157.67
Scenario 3	1.91	11.237	11.518	-	-
Scenario 4	2.33	1.255	-	40.87	42.03
Scenario 5	2.98	1.404	-	105.86	108.90
Scenario 6[4]	1.96	18.258	-	-	-
Scenario 7	1.78	1.255	-	-12.91	-13.27

[1] Applies in SMR-based H_2 production with electricity co-production (see Table 2).

[2] Applies in SMR-based H_2 production with steam co-production (see Table 2).

[3] Derived from the techno-economic model developed for a similar H_2 production plant size by Olateju et al. [7]. The costs are corrected to 2014 Canadian dollars using an inflation rate of 2.5% [7].

[4] The GHG abatement costs are not calculated for this scenario because the life cycle GHG emissions in this scenario are greater than the life cycle GHG emissions in the reference scenario (scenario 3).

Table 8: Comparison of GHG abatement costs with other relevant studies

Relevant studies	**Damen et al. [46]**	**Damen et al. [46]**	**Granovskii et al. [29]**	**Present Study**
H_2 end use and delivery pressure	Combined heat and power, 20 bar	Transport sector, 20 bar	Fuel-cell based automobiles, 20 bar	Bitumen upgrading
Pathways considered	Advanced Auto-Thermal Reforming (ATR), advanced CG	Advanced Auto-Thermal Reforming (ATR), advanced CG	Water electrolysis run by electricity produced from solar and wind	UCG-CCS, SMR-CCS
Carbon capture technology	MDEA (for ATR), Selexol (for CG)	MDEA (for ATR), Selexol (for CG)	-	Selexol
Jurisdiction	Netherlands	Netherlands	Canada	Alberta, Canada
H_2 transportation mode	Pipeline	Pipeline	-	Pipeline
CO_2 transportation mode	Pipeline	Pipeline	-	Pipeline
H_2 transportation	20 km transmission line	200 km transmission	Not explicitly stated	No H_2 transportation

distance, km	(for CG) or 200 km transmission line (for SMR) +125 km regional transmission line + 10 km high pressure distribution line	line +125 km regional transmission line + 70 km high pressure distribution line		for SMR-based H_2, 225 km for UCG-based H_2
CO_2 transportation distance, km	10 km	10 km	-	10-225 km
H_2 production costs, \$/kg-H_2				
ATR	-	-	1.77	-
ATR-CCS	1.92	3.46	-	-
CG-CCS	2.31	3.10	-	-
SMR-CCS	-	-	-	2.36-2.66
UCG-CCS	-	-	-	1.78-2.98
SMR	-	-	-	1.91
UCG	-	-	-	1.96
Emissions factor, kg-CO_2-eq/kg-H_2				
SMR	6.840	6.840	9.084	11.237-11.518

CG	12.360	12.360	-	-
SMR-CCS, CG-CCS	Range given: 1.2-4.8	Range given: 1.2-4.8	-	6.024-6.758
UCG	-	-	-	18.258
UCG-CCS	-	-	-	1.255-1.404
Solar	-	-	2.088	-
Wind	-	-	0.846	-
GHG abatement costs, \$CAD/tonne-CO_2-eq abated (reference system: SMR-based H_2 without CCS)				
Solar	-	-	2228.79	-
Wind	-	-	668.64	-
CG-CCS	257.93	320.81	-	-
ATR-CCS	230.98	310.11	-	-
SMR-CCS	-	-	-	86.83-157.67
UCG-CCS	-	-	-	40.87-108.9