Applied Energy 111 (2013) 428–440

Contents lists available at SciVerse ScienceDirect

Applied Energy

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

Techno-economic assessment of hydrogen production from underground coal gasification (UCG) in Western Canada with carbon capture and sequestration (CCS) for upgrading bitumen from oil sands

Babatunde Olateju, Amit Kumar *

Department of Mechanical Engineering, University of Alberta, Edmonton, Alberta, Canada T6G 2G8

HIGHLIGHTS

- Development of a techno-economic model for UCG-CCS and SMR-CCS.
- Estimation of H_2 production costs with and without CCS for UCG and SMR.
- UCG is more economical for H_2 production with CCS.
- SMR is more cost efficient for H_2 production without CCS.
- Cost competiveness is highly sensitive to the IRR differential between UCG and SMR.

ARTICLE INFO

Article history:
Received 22 November 2012
Received in revised form 23 April 2013
Accepted 1 May 2013
Available online 4 June 2013

Keywords:
Techno-economic assessment
Natural gas
Coal
Underground coal gasification
Carbon capture and storage

ABSTRACT

This paper examines the techno-economic viability of hydrogen production from underground coal gasification (UCG) in Western Canada, for the servicing of the oil sands bitumen upgrading industry. Hydrogen production for bitumen upgrading is predominantly achieved via steam methane reforming (SMR); which involves significant greenhouse gas (GHG) emissions along with considerable feedstock (natural gas) cost volatility. UCG is a formidable candidate for cost-competitive environmentally sustainable hydrogen production; given its negligible feedstock cost, the enormity of deep coal reserves in Western Canada and the favourable CO_2 sequestration characteristics of potential UCG sites in the Western Canadian sedimentary basin (WCSB). Techno-economic models were developed for UCG and SMR with and without CCS, to estimate the cost of hydrogen production including delivery to a bitumen upgrader. In this paper, at base case conditions, a 5% internal rate of return (IRR) differential between UCG and SMR was considered so as to account for the increased investment risk associated with UCG. The cost of UCG hydrogen production without CCS is estimated to be \$1.78/kg of H_2. With CCS, this increases to range of \$2.11–\$2.70/kg of H_2, depending on the distance of the site for CO_2 sequestration from the UCG plant. The SMR hydrogen production cost without CCS is estimated to be \$1.73/kg of H_2. In similar fashion to UCG, this rises to a range of \$2.14 to \$2.41/kg of H_2 with the consideration of CCS. Lastly, for hydrogen production without CCS, UCG has a superior cost competitiveness in comparison to SMR for an IRR differential less than 4.6%. This competitive threshold rises to 5.4% for hydrogen production with CCS.

1. Introduction

Hydrogen is a crucial feedstock to the oil sands industry as it is needed for the upgrading of bitumen to synthetic crude oil (SCO). Hydrogen demand is anticipated to reach 3.1 million tonnes/year in the industry by the year 2023 [1]; as oil sands production (a combination of SCO[1] and non-upgraded bitumen) is expected to rise from 1.6 million bpd in 2010 to 3 million bpd in 2020 [3]. In Alberta, as is the case in much of the globe, hydrogen is predominantly produced via steam methane reforming (SMR) [4–6]; which has a significant life cycle greenhouse gas (GHG) emissions footprint of about 11,000–13,000[2] tonnes of CO_2 equivalent per tonne of hydrogen produced [7–10]. Furthermore, the feedstock (i.e., natural gas) cost volatility [2,11] and the intensity of natural gas usage in the oil sands industry as a whole (natural gas is a premium fossil fuel with a significant opportunity cost) – raise questions about the

* Corresponding author. Tel.: +1 780 492 7797; fax: +1 780 492 2200.
E-mail address: Amit.Kumar@ualberta.ca (A. Kumar).

[1] Synthetic Crude oil production in Alberta amounted to 126,400 m^3/day in 2010 [2].

[2] Value based on the higher heating value (HHV) of hydrogen (141 MJ/kg).

0306-2619/\$ - see front matter
http://dx.doi.org/10.1016/j.apenergy.2013.05.014

Nomenclature

ASU	air separation unit
BOP	balance of plant
CCS	carbon capture and sequestration
CO_2	carbon dioxide
DCF	discounted cash flow
GHG	green house gas
GOA	Government of Alberta
H_2	hydrogen
HHV	higher heating value
IRR	incremental rate of return
LHV	lower heating value
PSA	pressure swing adsorption
SCOT	Shell Claus off-gas treating
SMR	steam methane reforming
UCG	underground coal gasification
WCSB	Western-Canadian sedimentary basin

sustainability of hydrogen production via SMR especially in an increasingly competitive and carbon constrained energy market. There is a lot of interest in the production of hydrogen from conversion pathways which have low GHG footprints. As a result, research into the development of sustainable hydrogen production pathways, without compromising economic viability and maintaining a negligible GHG footprint is warranted to facilitate the sustainable growth of the bitumen upgrading oil sands industry in North America and elsewhere.

Underground coal gasification (UCG) is a technology that in recent times, has gained increased attention in the global energy mix; especially in the context of clean coal technologies and carbon neutral energy pathways [12,13]. At the end of 2005, global coal reserves stood at approximately 850 billion tonnes [12]; UCG is expected to augment this figure by as much as 600 billion tonnes, an increase of about 71% [12]. In addition, some authors have estimated an increase in coal reserves in the range of 300–400% for particular jurisdictions such as the United States [13]. From a Canadian standpoint, the province of Alberta's proven coal reserves as of 2010 amounted to 36.8 billion tonnes [2], with a considerable amount viable for UCG. The viability of UCG in Alberta is substantiated by the fact that it houses a UCG plant (still in its demonstration phase) with the deepest coal seam gasification depth in the world (1400 m below ground) [14].

UCG involves the in situ gasification of deep coal seams otherwise inaccessible by conventional coal mining methods, for the production of synthesis gas (syngas) which has a multitude of downstream industrial uses – hydrogen production, power generation, liquid fuels etc. [13,15,16]. Syngas is mainly composed of hydrogen and carbon monoxide, with other species such as methane and carbon-dioxide to a lesser extent [15,17]. UCG has a number of advantages over above ground coal gasification plants, which can potentially facilitate superior cost competitiveness. Unlike surface gasification plants, the cost of a gasifier is mitigated, as the coal seam cavity created serves as the gasification unit. Furthermore, the cost associated with the purchase of coal, its transport and handling, along with its ash disposal are also abated with UCG [13,15,18]. The aforementioned economic gains associated with UCG come at the expense of reduced process control, along with productivity and environmental risks e.g. consistency of syngas quality and composition, land subsidence and ground water contamination [13,15–17]. That being said, the aforementioned risks of ground water contamination and land subsidence are reduced with increased coal seam gasification depths as well as the management of the coal seam gasification pressure[3] [13,15–17].

[3] Maintaining the UCG gasification cavity pressure below the surrounding hydrostatic pressure will reduce the risk of contamination. However, this has to be balanced against the effect on syngas quality e.g. calorific value, and other downstream processes which favour a higher syngas evolution pressure e.g. CO_2 capture. [13,17].

UCG lends itself as a formidable candidate for sustainable hydrogen production in Western Canada. In particular, the complementary nature of UCG and carbon capture and sequestration (CCS) technology is quite compelling. CCS technology includes the capture of CO_2 from the syngas generated through the UCG process and the injection of this CO_2 in a sink (such as underground geological storage or ocean storage) [19,20] .UCG sites have been known to co-exist in close proximity to geological formations which are suitable for CO_2 sequestration [13,17,21]. A study conducted by Friedmann et al. [13] reports that greater than 75% of current, planned, and pilot stage UCG projects lay within 50 km of saline aquifers which posses the capacity for CO_2 sequestration; not to mention the added close proximity to depleted oil and gas fields which present an opportunity for CO_2 enhanced oil recovery (EOR) operations [13]. This characteristic of UCG is further verified in the Western Canadian context. The Western Canadian Sedimentary Basin (WCSB) which spans the majority of the province of Alberta is known to have favourable CO_2 sequestration properties [22,23]; furthermore, the vast coal resources of Alberta are also contained in the WCSB [24]. In complementary fashion, CCS implementation with large fossil fuel driven energy systems is the focal point of the Alberta government's strategy to reduce GHG emissions [24,25]. The Government of Alberta (GOA) aims to reduce GHG emissions by 200 million tonnes in the year 2050 with respect to 2005 GHG emission levels [24].

Thus, the synergy that can be realised from hydrogen production via UCG-CCS in the Western Canadian context deserves research attention, as the conditions that exist in terms of the geology, resource wealth and vested governmental interest, facilitate a fertile ground for its implementation. The published literature on the integration of CCS with large scale energy systems is in-depth and multi-faceted in nature; with technological, economic, environmental, and regulatory aspects being addressed exhaustively [19,26–32]. Contrastingly, in the case of UCG, much of the focus in the existing literature has been geared towards UCG process simulation and optimisation; as well as environmental impact monitoring [33–38]. While this is undoubtedly important, the appraisal of UCG-CCS from a techno-economic perspective in published literature is scarce. More often than not, the appraisal of UCG in a techno-economic context is qualitative with limited detail [13,15,17]. Admittedly, this is likely due to the infancy of the technology and the limited operational experience on a commercial large scale. The above ground (surface) gasification of coal and the subsequent processing of the syngas evolved for hydrogen production is a mature well understood technology. The process methodology for syngas-H_2 conversion is identical for both surface gasification and UCG plants. In both cases syngas is processed above ground, and the syngas composition, temperature and pressure are of similar magnitudes [13,15]. As a result, this enables the techno-economic modelling of UCG to be carried out credibly, within reason. The techno-economic modelling of UCG-CCS with the explicit consideration of its apparent

Table 1
Scenarios of hydrogen production with CCS .

Scenarios	SMR/UCG based H_2 production	With/without CCS	Description	Assumptions/comments
Scenario 1	SMR	With CCS	H_2 production at Fort Saskatchewan, Alberta; with CO_2 sequestration in Thorhild, Alberta via 84 km CO_2 pipeline	Based on CO_2 sequestration location and pipeline distance for the Shell Quest CCS project [42]
Scenario 2	SMR	With CCS	H_2 production at Fort Saskatchewan, Alberta; with CO_2 sequestration in Swan Hills, Alberta via 225 km CO_2 pipeline	Based on the premise that the CO_2 sequestration reservoir is located within a 10 km radius of the UCG coal resource in Swan Hills, Alberta. A high potential for spatial co-location of UCG coal resources and CCS reservoirs is highlighted by [13,17,21]. Driving distance used to estimate pipeline length [43]
Scenario 3	SMR	Without CCS	H_2 production at Fort Saskatchewan, Alberta	
Scenario 4	UCG	With CCS	H_2 production at Swan Hills, Alberta with H_2 delivery to Fort-Saskatchewan, Alberta via 225 km H_2 pipeline; along with CO_2 sequestration within a 10 km radius of the UCG plant	Based on high spatial coincidence between UCG coal resources and CCS reservoirs (see scenario 2 assumptions). Driving distance used to estimate pipeline length [43]
Scenario 5	UCG	With CCS	H_2 production at Swan Hills, Alberta with H_2 delivery to Fort-Saskatchewan, Alberta via 225 km H_2 pipeline; along with CO_2 sequestration in Thorhild, Alberta via 184 km CO_2 pipeline	Based on the premise that the high spatial coincidence does not hold true. Hence, CO_2 sequestration reservoir is located a relatively large distance away from the UCG plant. Driving distance used to estimate pipeline length [43]
Scenario 6	UCG	Without CCS	H_2 production at Swan Hills, Alberta with H_2 delivery (via 225 km H_2 pipeline) to Fort-Saskatchewan, Alberta	Driving distance used to estimate pipeline length [43]
Scenario 7	UCG	With CCS	H_2 production at Swan Hills, Alberta with H_2 delivery (via 225 km H_2 pipeline) to Fort-Saskatchewan, Alberta; along with the sale of CO_2 for enhanced oil recovery (EOR) operations	EOR operators are assumed to be in within a 10 km radius of the UCG plant. As of 2009, Alberta had an EOR storage capacity estimate of about 450 million tonnes [25]

cost-competitiveness and environmental risks is needed to provide a quantitative and qualitative view of its utility as a hydrogen production pathway in comparison to conventional methods such as SMR-CCS. In addition, this will also facilitate the identification of areas of cost minimisation and key sensitivities. Furthermore, the techno-economic insight gained has the potential to enhance the galvanisation of investor interest both from industry and governmental bodies.

As a result, the primary objective of this paper is the development of a data-intensive techno-economic model for UCG-CCS, which will yield a credible estimate of the cost of hydrogen production in a Western Canadian context. For comparative reasons, a SMR-CCS techno-economic model was also developed in similar fashion, to yield the cost of hydrogen production. The techno-economic models developed in this research are partly based upon existing above ground coal gasification[4] and SMR plant models provided in earlier studies [39–41]. Adjustments and refining of the model architecture used [39–41], as well as the modification of data inputs were carried out to ensure specificity to Western Canadian conditions as reasonably possible. All costs specified in this paper are in 2010 Canadian dollars.[5] Seven different hydrogen production scenarios were assessed in terms of the cost of hydrogen production. These scenarios included the cost assessment of hydrogen production with CCS and without CCS. The details on these scenarios are given below.

2. Hydrogen production with CCS – scenarios in Western Canada

A multitude of practical and viable scenarios for hydrogen production with the added feature of CCS exists in Western Canada. To account for these various options in the implementation of a SMR-CCS plant and UCG-CCS plant, seven scenarios are considered in this study (see Table 1). For all the scenarios considered, the SMR-CCS plant location is in Fort-Saskatchewan Alberta, as this is an industrial heartland of the province suitable for plants of this nature (Fig. 1 shows the location of Fort-Saskatchewan in Alberta). In similar fashion, the UCG-CCS plant is located in Swan Hills Alberta for all the scenarios considered (as shown in Fig. 1). The distinction associated with each scenario relates to the location of the CO_2 sequestration site, and consequently, the length of the CO_2 pipeline. Also, the fate of the CO_2 evolved at the plant i.e. whether captured and sequestered, released into the atmosphere, or captured and sold for revenue, is another distinction.

It is important to stress that scenarios 1 and 4 represent the baseline scenarios for SMR-CCS and UCG-CCS, respectively. As a result, all the subsequent analysis conducted in this study is based on the plant configurations in these scenarios unless otherwise specified.

3. Hydrogen production with UCG-CCS

3.1. UCG technological overview

Underground coal gasification involves the sub-surface gasification of a coal seam, with the use of oxygen/air and steam at elevated temperatures for the in situ production of synthesis gas (syngas) [15–17]. The coal seam is accessed via the drilling of an injection well, and the syngas produced is channelled up a production well as shown in Fig. 2. Advances in drilling technology have enabled the gasification of coal seams at depths previously considered as impractical and economically prohibitive. Prime examples of the advances in technology that enable access to deep coal seams and the (limited) control of the UCG process include the continuous retraction injection point (CRIP) process and the proprietary εUCG process.[6] The CRIP process was developed by Lawrence Livermore Laboratories over two decades ago [15]. The CRIP

[4] The above ground coal gasification model is comprised of a two-part study [39,40].
[5] An inflation rate of 2.5% has been used to convert all currencies into 2010 $CAD. In addition, an exchange rate of $US 0.8 = $CDN 1 has been utilized in this study.
[6] The εUCG process was developed by Ergo Exergy Inc.

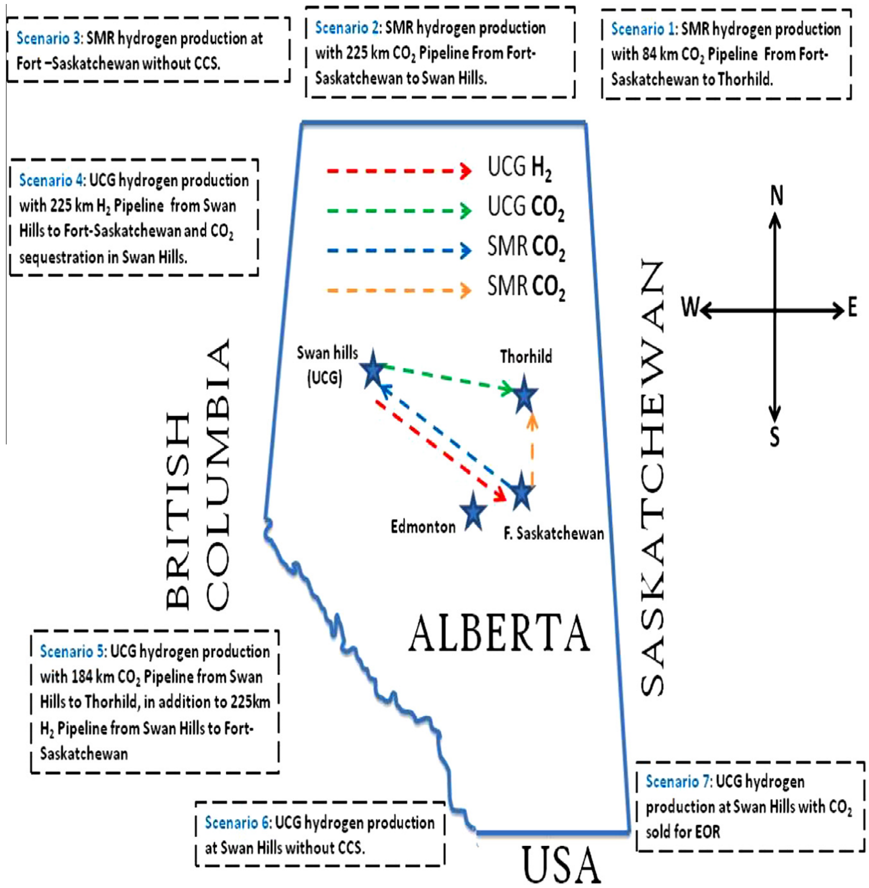

Fig. 1. Geographical depiction of hydrogen production with CCS scenarios.

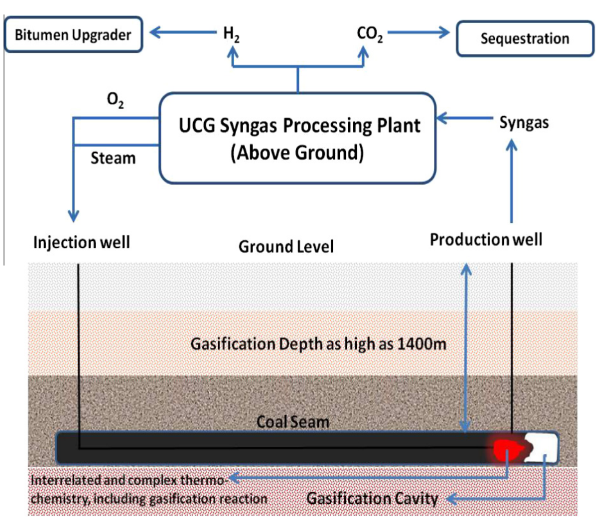

Fig. 2. Schematic diagram of UCG-CCS. *Notes*: UCG involves a multitude of intricate reactions [15]; including: (1) gasification reaction: $C + H_2O \rightarrow H_2 + CO$, (2) shift conversion: $CO + H_2O \rightarrow H_2 + CO_2$,(3) methanation: $CO + 3H_2 \rightarrow CH_4 + H_2O$, (4) hydrogenating gasification: $C + 2H_2 \rightarrow CH_4$, (5) partial oxidation: $C + 0.5O_2 \rightarrow CO$, (6) oxidation: $C + O_2 \rightarrow CO_2$, (7) boudouard reaction: $C + CO_2 \rightarrow 2CO$.

process involves the vertical drilling of a production well, and then the use of directional drilling to produce an injection well that connects to the production well [15]. Once a channel between the production and injection wells is established, a gasification cavity is created at the end of the injection well in the horizontal section of the coal seam, with the introduction of the gasification agents [15] (see Fig. 2). As the gasification process proceeds, the coal seam in the cavity initially created will eventually be exhausted. The process is given continuity by the retraction of the injection point – achieved (preferably) with the burning of a section of its liner [15]. This creates a new gasification cavity which allows the continued production of syngas until the coal seam region accessed is used up.

A few competing factors and characteristics are associated with UCG which are worth highlighting. First, the coal seam thickness is a key parameter for the viability of a given UCG project. A coal seam thickness of 2 m is considered to be the minimum threshold for economic viability [16]. The coal seam[7] (Mannville coal) to be utilised in the proposed UCG plant has been characterised with a seam thickness varying from 6 to 10 m [44]. This further demonstrates the quality of the resource that exists in Alberta.

Secondly, a balance between the amount of oxygen and steam introduced into the coal seam cavity must be maintained. Increased oxygen supply improves the concentration of CO_2 in the syngas stream, thus facilitating the ease of CO_2 capture downstream [16]. However, the increased CO_2 content decreases the calorific value of the syngas as CO_2 is inert [16]. Considering that the desired end use of the syngas in this study is hydrogen production

[7] In the techno-economic model developed, the characteristics of Illinois #6 coal in terms of its composition and calorific value have been adopted [39]. That being said, the caloric value of the coal utilized has a negligible effect on the model accuracy, as the coal feedstock cost utilized in this study is nil (see Table 3). In addition, the syngas → H_2 and CO_2 conversion pathway for Illinois #6 coal provides a suitable benchmark for estimating the anticipated cost of UCG based hydrogen from Mannville coal in Western Canada. The syngas composition of both coal types is expected to be in the same order of magnitude.

Table 2
UCG-CCS plant specification.

Plant specifications	Values	Sources/comments
UCG plant design capacity	660,000 kg H_2/day	Determined based on a plant H_2 output of 1052.4 MW_{TH} [39]. A H_2 LHV of 119.96 MJ/kg was adopted
Plant capacity factor	85%	[41]
Coal consumption	5574[a] tonnes/day	Determined using a Mannville coal calorific value of 28.5 MJ/kg [45]
Water (steam) consumption	0.5 kg/kg coal	[39]
UCG coal to H_2 efficiency	50%[b]	[48]
Hydrogen production pressure	60 bar	[39]
CO_2 flow rate	11,302 tonnes/day	Based on a CO_2 flow rate of 554 tonnes/h [40], along with the consideration of the plant capacity factor
Bitumen upgrader specification		
Shell Scotford Upgrader capacity	290,000 bpd	Shell Canada has obtained approval from the Alberta Energy and Utilities Board for expansion of its upgrader to a capacity of 290,000 bpd [49]
Synthetic crude oil (SCO) production	246,500 bpd	A bitumen to SCO volumetric conversion ratio of 0.85 is utilised [50,51]
H_2 consumption for SCO production	3.4 kg/barrel	An average of hydrogen consumption for a multitude of oil sands extraction and upgrading technologies is assumed [52]
H_2 supply required	838,100 kg H_2/day	

[a] Includes the additional coal consumption used to raise steam.
[b] Efficiency value is based on efficiency of a 300 MW_e UCG power generation plant [48].

with CCS, as opposed to power generation, there is likely to be a bias in the amount of oxygen added in practice. The addition of steam on the other hand increases the calorific value of the syngas; however, a surplus amount of steam can potentially extinguish the gasification process [16].

The permeability of the coal seam is also important as it facilitates the increased flow of the syngas produced [13,16]. Coal seams with high permeability are desirable; however, this is seldom found in practice [16]. As a result, a coal resource of low-calorific value is often seen as ideal for UCG in the context of syngas flow. This is because these low grade coal types usually shrink upon gasification as opposed to expanding, which aids syngas flow [15,16]. Mannville coal is a sub-bituminous coal with an average caloric value of 28.5 MJ/kg[8] [45].

Another influential parameter is the pressure of the coal seam, which invariably dictates the pressure of the gasification process. Apart from influencing the reactions that take place in the coal seam, the partial pressure of CO_2 is also an important parameter for capture [28]. Higher partial pressures are desired for CO_2 capture [28]; consequently, a high gasification pressure is also ideal. The coal seam pressure reported by Swan Hills Synfuels for their Mannville coal seam is about 13 MPa [46].

4. UCG-CCS plant model

An above surface coal gasification plant model developed in earlier studies [39,40] is utilised in this paper as an approximation of the UCG-CCS process. The model was modified wherever required to replicate conditions specific to UCG.

The plant proposed in earlier studies [39,40] has a number of configurations ranging from the production of mainly hydrogen or electricity, syngas cooling methods, and the venting or capture of the CO_2 produced. The configuration where mainly hydrogen is produced along with carbon capture is of particular relevance to this study. The plant configuration adopted from literature also involves the gasification of coal at a pressure of 120 bar in an entrained flow gasifier with 0.5 kg of warm water consumed per kilogram of coal [39]. A gasification pressure of 120 bar is a reasonable approximation, given that Mannville coal seam pressures have been reported to be in the range of 9–13 MPa [46,47]. The warm water usage is however not applicable to UCG which requires steam. In this study, it is assumed that 0.5 kg of steam at an elevated temperature of 1227 °C is required per kilogram of coal. The injection of the oxygen and steam mixture for UCG is reported to be at a temperature of 1227 °C [16]. It is assumed in this study that the heat content of this mixture is solely due to steam. The energy used to raise steam at the aforementioned temperature is assumed to be provided by Mannville coal with an efficiency of 70% and a price of $0/tonne. In reality, this additional energy will likely be provided by the syngas evolved during UCG, and would mitigate the need to utilise coal. However, due to a scarcity of data on UCG syngas properties in Alberta, this assumption was made, as its effect on production cost is likely to be non-existent. Table 2 gives a summary of the UCG-CCS plant characteristics along with the bitumen upgrader plant specification. Some of the major base case assumptions of the study and input data are shown in Table 3 below.

4.1. Cost estimation of UCG-CCS in Western Canada

4.1.1. Plant equipment capital costs

The capital costs of the plant equipment for the UCG-CCS plant in this study are primarily based on the costs specified for the above ground coal gasification plant [40]. As mentioned earlier, the high degree of similarity between UCG and above ground gasification enables the reasonable estimation of the costs associated with UCG especially considering above ground plant infrastructure. The costs associated with the CCS element of the plant are estimated based on available data in literature, CCS models, and data derived from industry. The UCG-CCS plant equipment capital costs are listed in Table 4 (all costs are rounded up to the nearest million).

4.1.2. Hydrogen storage costs

The requirement of hydrogen storage is not crucial as in the case of SMR. This is due to hydrogen production in the case of UCG is not being captive.[9] The hydrogen produced will be pipelined to the bitumen upgrader as opposed to being consumed 'in-house' as is in the case of the SMR-CCS plant. Furthermore, in a UCG plant, the syngas produced is more likely to be stored as opposed to the storage of hydrogen. As a result, this study assumes hydrogen storage cost, if

[8] The average calorific value of Mannville coal considering a range of 26.8–30.2 MJ/kg was utilized [45]. As a comparison, the calorific value of Illinois #6 coal amounts to 26.14 MJ/kg HHV [39].

[9] Captive hydrogen production means that the hydrogen is consumed in the same place where it is produced.

Table 3
UCG-CCS model principal economic data.

Parameter	Value	Sources/comments
Base case coal price	$0/tonne	Coal feedstock cost is considered to be negligible
Electricity cost	$0.07/kW h	Average cost of electricity in Alberta utilised [53]
Inflation	2.5%	
Base case internal rate of return (IRR)	15%	An increased IRR for UCG relative to SMR is reflective of the technological infancy of UCG on a large commercial scale as well as its increased environmental and production reliability risks in comparison to SMR
Plant equipment O&M factor	4% of Capital cost	[54]
Albertan installation factor	1.65	The harsh Albertan climate and labour shortage warrants increased installation costs. Installation factor adopted is 15% higher than that for a North-American large scale fossil fuel plant proposed by Ogden [54]
Number of plant operators	8	Number of plant operators required is assumed to be equivalent to the SMR-CCS plant. (see section 5)
Supervision and administration cost	$1,300,000	Estimated to be 80% of annual operator labour cost [41]
Plant lifetime	40[a] years	
Financial year	2010	

[a] The only existing commercial scale UCG plant (Linc Energy's Yerostigaz plant located in Angren, Uzbekistan) has been in operation since 1961 [55]. This plant is expected to maintain commercial operation for another 50 years [55]. However, a more conservative approach regarding plant lifetime estimation which is reflective of typical coal-fired power plants is adopted in this study.

Table 4
UCG-CCS capital costs.

Equipment	Cost ($CAD millions)	Sources/comments
Drilling of injection and production wells	68	[56][a]
Air separation unit (ASU)	142	[40][b]
O_2 compressor	29	[40][b]
Syngas quenching	231	[40][b]
WGS reactors and heat exchangers	92	[40][b]
Selexol H_2S removal and stripping	125	[40][b]
Sulphur recovery (Claus SCOT)	85	[40][b]
Selexol CO_2 absorption and stripping	88	[40][b]
PSA unit	34	[40][b]
PSA purge gas compressor	13	[40][b]
Siemens V64.3A gas turbine	47	[40][b]
Heat recovery steam generator (HRSG)	35	[40][b]
Steam turbine and condenser	84	[40][b]
CO_2 drying and compression	154	[57][c,d]
CO_2 pipeline	9	[57][c,d]
CO_2 injection and sequestration	9	[58][e]
Hydrogen pipeline	325	[59][d,f]
Total	1569	Estimate is comparable to the Swan Hills Synfuels project cost of $CAD 1.5 billion [60].

[a] Drilling cost obtained from TEXYN Inc, was provided by Williams and Heidrick [56]; with labour and installation factors for Alberta considered by the authors.
[b] Cost quoted includes installation, apportioned balance of plant (BOP) and general facilities, engineering and process/project contingencies [40]; as a result, the installation factor was not applied to these costs to avoid exaggerated estimates.
[c] Cost was estimated using models provided by McCollum and Ogden [57].
[d] Installation factor applied.
[e] Cost is assumed to be equivalent to the CO_2 pipeline capital cost [58].
[f] Estimated using hydrogen pipeline cost model provided by [59].

at all applicable, will be incurred by the bitumen upgrader in Fort-Saskatchewan.

4.1.3. Hydrogen compression costs

In the model developed for this study, hydrogen exits the pressure swing adsorption (PSA) unit at a pressure of 60 bar [39]. Thus, additional compression for pipeline transport is unwarranted. Hence, the cost of purchasing a hydrogen compressor is mitigated for the UCG-CCS plant.

4.1.4. CO_2 compressor and pump costs

The compression of CO_2 to its supercritical phase is not just favourable for sequestration but also for its pipeline transport. CO_2 in its supercritical state has a viscosity about a hundred times lower than its liquid state [61]. This reduces frictional losses, which help to reduce fluid pressure losses in the pipeline. Furthermore, in its supercritical state, it exhibits the density of a fluid and thus allows for a higher throughput (mass flow rate) than would be the case in its gaseous form [61]. CO_2 is usually compressed to a pressure of about 150 bar for its supercritical pipeline transport [57,61]; with a limitation on the maximum pressure level to ensure the structural integrity of the pipeline e.g. flanges [61].

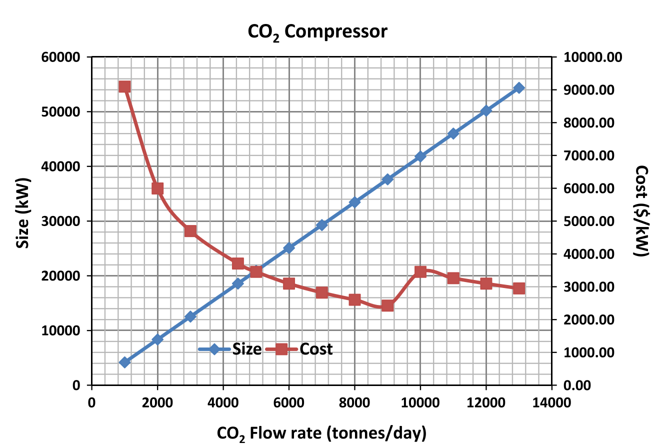

Fig. 3. CO_2 compressor capital cost.

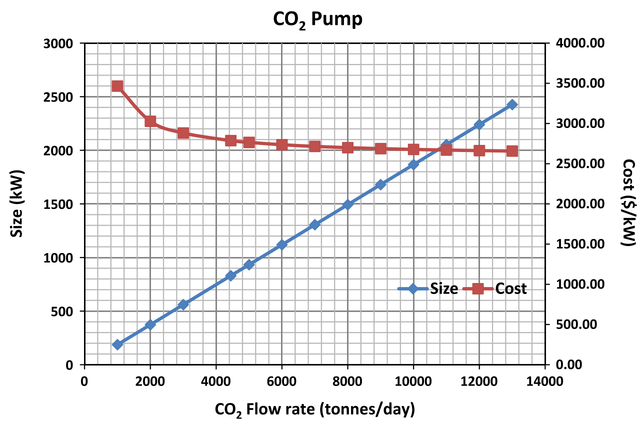

Fig. 4. CO_2 pump capital cost.

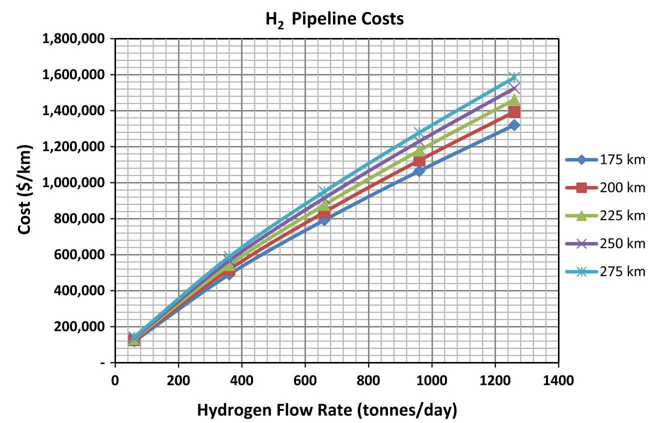

Fig. 6. H_2 pipeline capital cost.

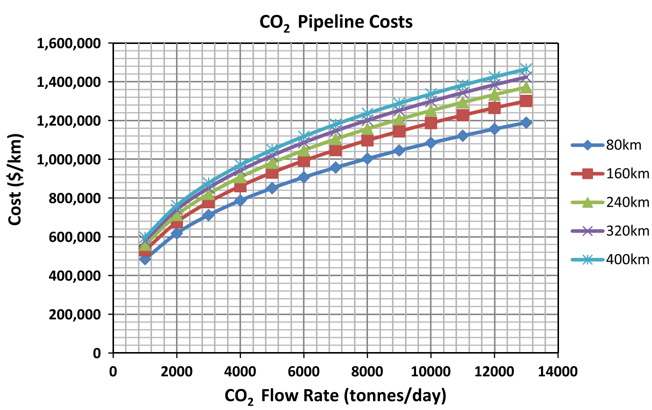

Fig. 5. CO_2 pipeline capital cost.

A compressor is required to compress the gaseous phase CO_2 captured at the plant to its critical pressure of 73.8 bar[10] [57]. Once this critical pressure is achieved, the CO_2 in its 'dense' supercritical phase is then compressed using a pump to its final pressure of 150 bar [57]. Using models developed earlier [57], the cost of CO_2 compression and pumping applicable to both UCG and SMR is illustrated in Figs. 3 and 4.

4.1.5. CO_2 pipeline characterisation and costs

For the UCG-CCS plant CO_2 flow rate of 11,302 tonnes/day [40], a pipeline diameter of 8.5 in. was determined using the iterative CO_2 pipeline model provided in an earlier study[11] [57]. Recall that this diameter was determined for a 10 km CO_2 pipeline as stipulated in scenario 4 (see Section 2). The CO_2 pipeline model adopted in this study stems from the average of seven other credible CO_2 pipeline models [54,62–67] which were compared on a consistent model input basis [57]. Thus, the model is assumed to be realistic and fit for purpose for the characterisation of the pipeline along with the estimation of costs. The pipeline diameters presented in this study are given in their actual values without rounding up/down to nominal pipeline sizes so as to illustrate their effect on estimated costs. In actuality, the pipeline diameters will be increased when necessary during manufacture, to conform to nominal pipeline standards. Fig. 5 illustrates the variation of the CO_2 pipeline cost with the pipeline flow rate and distance.

[10] CO_2 has a critical pressure and temperature of 73.8 bar and 31.1 °C.

[11] The CO_2 pipeline characterization and cost for the SMR-CCS plant was determined in identical fashion.

4.1.6. H_2 pipeline characterisation and costs

The characterisation of the hydrogen pipeline required the determination of two principal pipeline parameters i.e. the pipeline diameter and pipeline length. The diameter of the hydrogen pipeline was calculated with the use of the Panhandle – B equation [68]. This equation was solved with a reverse engineering approach to obtain the required diameter for the plant's hydrogen flow rate of 660 tonnes/day. As mentioned in preceding sections, the pipeline length was estimated with the use of the driving distance between Swan Hills and Fort-Saskatchewan [43]. The hydrogen pipeline cost model utilised in this study is based on a model provided in literature [59] (see Fig. 6). The cost estimated using this model was benchmarked against alternative hydrogen pipeline capital cost estimation models [67,69]. The difference in the pipeline capital cost between the model adopted in this paper and the models presented by Parker [67] and Johnson and Ogden [69] were 10% and 18% respectively. Similar to all pipelines, hydrogen pipeline capital costs will be highly site specific, and the consideration of the special pipeline seals required for hydrogen transport and the possible embrittlement of steel will play a significant role in determining costs [67]. In general, there is an increased risk of pipeline operation associated with hydrogen pipelines in comparison to other industrial fluids (e.g. CO_2, natural gas etc.) which has to be factored into the cost estimates for improved accuracy. It is worth pointing that in 2010, the Government of Alberta approved the construction of a hydrogen pipeline by Air Products Inc. to transport hydrogen from the company's two production facilities to bitumen upgraders, refineries and chemical processors etc. [70].

4.1.7. H_2 production cost

A data intensive discounted cash flow (DCF) spreadsheet model of the UCG-CCS plant was developed to ascertain the hydrogen production cost for each scenario considered in this study. Having completed the sizing and cost estimation of the required equipment and processes, the use of the economic data and assumptions along with the plant specification data (see Tables 2 and 3 in the case of UCG-CCS) allowed for the deduction of the production cost via a DCF model. It is worth pointing out that the production cost for the SMR-CCS plant was determined with identical methodology.

5. Hydrogen production with SMR-CCS in Western Canada

5.1. SMR technological overview

Steam methane reforming is a mature well understood technology in industry, that accounts for the majority of hydrogen production in Alberta and the globe. For detailed technological insight into SMR and its use with CCS, the reader is referred to the work

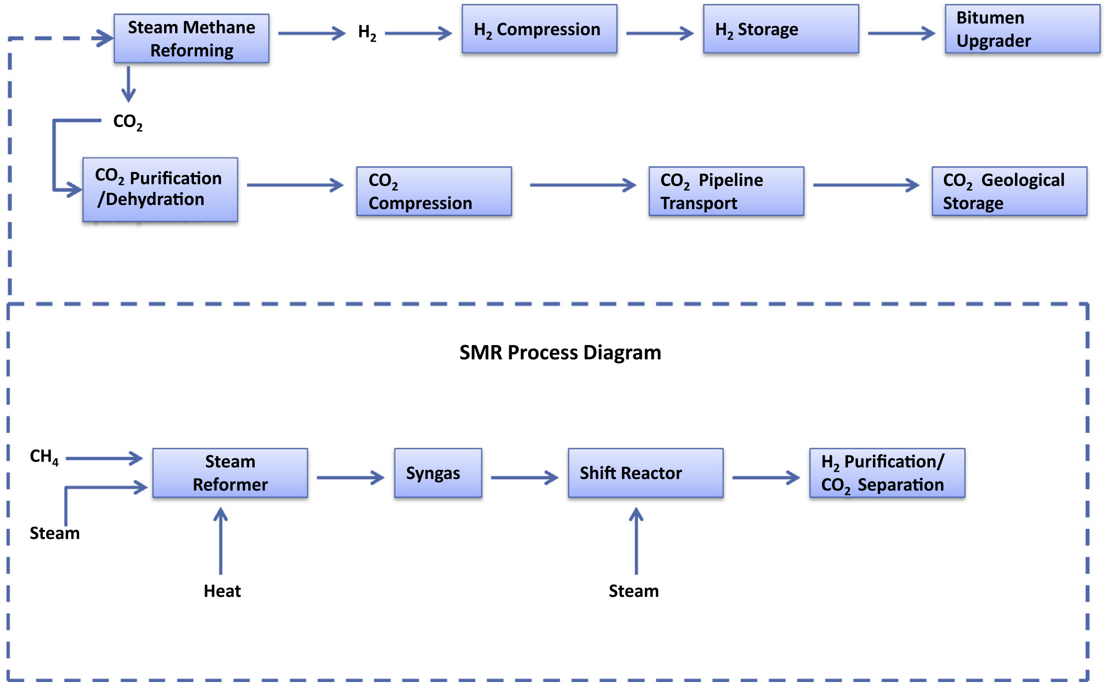

Fig. 7. SMR-CCS plant model.

Table 5
SMR-CCS plant specification.

SMR plant specification		Sources/comments
SMR plant design capacity	607,000 kg H_2/day	[41]
Plant capacity factor	90%	[41]
Hydrogen production pressure	70 bar	Hydrogen is compressed from a PSA output pressure of 14 bar to 70 bar, with the aid of a hydrogen compressor
Natural gas to H_2 conversion ratio (GJ/GJ H_2)	1.315	[41]
CO_2 flow rate	4406 tonnes/day	Based on a CO_2 flow rate of 204 tonnes/hr [41], along with the consideration of the plant capacity factor
Bitumen upgrader specification		
Shell Scotford upgrader capacity	290,000 bpd	See Table 2
Synthetic crude oil (SCO) production	246,500 bpd	See Table 2
H_2 consumption for SCO production	3.4 kg/barrel	See Table 2
H_2 supply required	838,100 kg H_2/day	See Table 2

carried out by the International Energy Agency (IEA) [41] and the literature authored by Molburg and Doctor [71].

5.2. SMR-CCS plant model

A qualitative summary of the SMR-CCS plant model is provided in Fig. 7. The plant model utilised in this study is based on a Foster Wheeler SMR-CCS plant developed for the International Energy Agency (IEA) [41]. Foster Wheeler is a leading player in the design and manufacture of industrial scale SMR plants; thus, the plant specified is assumed to be representative of the current technology. The Foster Wheeler plant considered here has a hydrogen production flow rate of 607 tonnes/day. Hence, it mitigates about 72% of the Shell Scotford Upgrader's hydrogen demand; details of the plant characteristics are provided in Table 5.

In the model developed, a number of plant equipment and downstream processes have been added to the earlier model [41] to ensure its specificity to the bitumen upgrading industry in Alberta. The costs of hydrogen storage and compression have been included in the model. In addition, the number of operators required for the SMR-CCS plant has been assumed to be eight; which is in good agreement with the 9.5[12] operators for a current CCS demonstration plant [72]. Also, remuneration of operators has been assumed to be more specific to Alberta with an operator's annual salary of $70,000. Furthermore, explicit determination of the cost of CO_2 compression and pipeline transport were not considered in earlier studies [39,41]. Hence, the determination of the required sizes of certain equipment e.g. CO_2 pump and compressor, as well as the characterisation of the CO_2 pipeline have been added to the current model developed in this study.

Some of the major base case assumptions and input data of the SMR-CCS model are given in Table 6 below.

6. Cost estimation of SMR-CCS in Western Canada

6.1. Plant equipment costs

The costs of plant equipment were derived from a number of studies and in consultation with experts. Wherever costs were

[12] A shared electrician is the reason for the fraction of operators [72].

Table 6
SMR-CCS model principal economic data.

Parameter	Value	Sources/comments
Base case natural gas cost	$5/GJ	Estimated average value of the natural gas price for the entirety of the plant lifetime
Electricity cost	$0.07/kW h	[53]
Inflation	2.5%	
Base case Internal Rate of Return (IRR)	10%	A reduced IRR for SMR relative to UCG is reflective of the technological maturity of SMR on a large commercial scale as well as its reduced environmental and production reliability risks in comparison to UCG
Plant equipment O&M factor	4% of Capital cost	[54]
Albertan installation factor	1.65	See Table 3
Plant lifetime	25 years	[41]
Number of plant operators	8	
Plant operator salary per annum	$70,000	Estimated average salary in Alberta for a plant operator. Operators are to have 3 daily 8 h shifts [41]
Supervision and administration cost	$1,300,000	Estimated to be 80% of annual operator labour cost [41]

Table 7
SMR-CCS capital costs.

Equipment	Cost ($CAD millions)	Sources/comments
Reformer	120	[41]
H2 purification	103	[41]
WGS reactor, steam generator etc.[a]	309	[41]
Catalysts and chemicals	16	[41]
Contingency cost	69	[41]
H_2 storage	407	Estimated using model provided by [54]
H_2 compressor	41	Estimated using model provided by [54]
CO_2 compressor and pump	71	Estimated using model provided by [57]
CO_2 pipeline	69	Estimated using model provided by [57]
CO_2 sequestration	69	CO_2 sequestration capital cost is assumed to be equivalent to pipeline capital cost [58]
Total	1272	

[a] This includes steam raising, power production, water gas reaction shift equipment, along with bulk materials such as piping, electrics and instrumentation.

Table 8
Hydrogen compressor characteristics.

H_2 compressor	Values	Sources/comments
Hydrogen production pressure from PSA (bar guage)	14	[41]
Required pressure for storage (bar guage)	70	[54]
Compressor efficiency	0.7	[54]
Number of compression stages	2	[54]
Compressor power requirement (MW)	19.32	[54]
Compressor capital cost ($CAD/kW)	937.5	[54]

not available these were developed based on suitable assumptions. A summary of the plant costs considered in this study is provided in Table 7 (all costs are rounded up to the nearest million).

6.2. Hydrogen storage costs

A storage capacity of 50% (i.e. 12 h of daily hydrogen production) is a reasonable estimate for the SMR-CCS plant, and is similar to that utilised in an earlier study [54]. It is important to point out that the storage capacity can vary from 12 to 24 h of production, which can have a significant impact on storage costs. As is predominantly the case in Alberta, 95% of hydrogen production in the world is captive [73]; hence, depending on specific conditions, e.g., frequency of hydrogen production lulls, the storage capacity required at a given plant will vary.

Above ground high pressure storage vessels are to serve as the storage medium for the plant. The hydrogen produced at the SMR-CCS plant leaves the PSA unit at a pressure of about 14 bar. It is then compressed to a pressure of about 70 bar to be suitable for storage in the pressure vessels. In this study, the storage specific cost amounted to $5,798/GJ H_2 [54].

6.3. Hydrogen compression costs

The compressor power required for hydrogen storage at the desired storage pressure of 70 bar was determined using a model developed in an earlier study [54]. Details of the compressor characteristics and costs are provided in Table 8.

7. Results and discussion

7.1. CO_2 compression

The need for compression is common to all scenarios involving CO_2 capture and sequestration, regardless of the hydrogen production pathway i.e. UCG or SMR. The total power rating and pressure output of the CO_2 compression equipment determined for the UCG-CCS plant were 48.1 MW and 15 MPa. For the SMR-CCS plant, these values correspond to 19.2 MW and 15 MPa. The significant difference in the power rating of the aforementioned compressors is due to the fact that the UCG-CCS plant has a CO_2 flow rate which is considerably greater than its SMR counterpart. The power rating of the compressor is particularly relevant from an economic standpoint, as it determines the capital cost incurred. In comparison to industrial standards, the CO_2 compression model utilised in this study is quite accurate. For comparative purposes, it is worth mentioning that a current CCS demonstration plant uses a 17 MW compressor with a pressure output of 14 MPa [72]. This is comparable to the SMR-CCS plant parameters; however, the demonstration plant compressor was sized for a reduced flow rate of 3300 tonnes/day. Notwithstanding, the realistic nature of the compressor model is still apparent.

As shown in Fig. 3, the cost of CO_2 compression decreases in a non-linear fashion as the CO_2 flow rate is increased. Hence, it can be inferred that CO_2 compression is more cost effective (in \$/kW) at larger scale plants relative to smaller ones; as a result of benefits from economies of scale. Fig. 3 also shows that at a CO_2 flow rate greater than 9566 tonnes/day, the compressor capital cost rises. This is as a result of two compressor trains being required for a compressor size greater or equal to 40 MW [57]. The pumping of CO_2 from its supercritical 'dense' phase to the final pressure of 150 bar entails significantly reduced capital costs compared to compression (as illustrated in Fig. 4). This difference is mainly due to the high compression ratio associated with the compressor, which is greatly reduced with the pump. However, the economies of scale that can be achieved with the pump are less significant in comparison to the compressor. Fig. 4 shows that for a CO_2 flow rate greater than 5000 tonnes/day, the cost savings (\$/kW) for the pump become relatively insignificant.

7.2. CO_2 pipeline

The pipeline cost of transporting the CO_2 evolved at the plant to the sequestration location, for different pipeline lengths, is shown in Fig. 5. The pipeline cost per unit distance increases with both an increase in distance and CO_2 mass flow rate. However, the gradient of the cost curves in Fig. 5 gradually decreases as the magnitude of the flow rate is increased. Furthermore, it can be seen that at smaller CO_2 mass flow rates, the impact of length on the cost is less significant in comparison to higher flow rates. Fig. 5 also illustrates that as the pipeline length increases, the differences in the capital cost per unit distance for each CO_2 mass flow rate considered, becomes increasingly reduced. Thus, it can be inferred that the pipeline cost becomes more economical as its scale is increased. Lastly, the cost per unit distance is shown to be more sensitive to the magnitude of the flow rate, as opposed to the pipeline distance. The diameter of the pipeline is invariably tied to the mass flow rate and thus determines how much material is required for the pipeline construction as well as manufacturing costs. This is reflected in the pipeline cost estimation model utilised in this study [57]; as the mass flow rate has a greater exponent in comparison to the pipeline length.

7.3. Hydrogen pipeline

The hydrogen pipeline cost per unit distance (as shown in Fig. 6) increases with an increase in the pipeline length and hydrogen flow rate. Intuitively, the cost per unit distance is highly sensitive to the mass flow rate and less sensitive to the pipeline length; again, this is due to the costs of materials and manufacturing being strongly linked to the pipeline diameter which is invariably tied to the mass flow rate. Furthermore, in similar fashion to the CO_2 pipeline, the sensitivity of costs to the pipeline length increases as the mass flow rate is increased.

In comparison to the CO_2 pipeline some differences exist which are worth pointing out. Fig. 6 illustrates that the hydrogen pipeline is more expensive; which can be attributed to the specialised pipeline materials and seals [67], along with the low density of compressed hydrogen in comparison to supercritical CO_2. This relatively low density results in a significantly reduced mass flow rate in the pipeline which increases the cost per unit.

7.4. UCG hydrogen production cost

At base case conditions (IRR of 15% and a coal price of \$0/tonne), the hydrogen production cost from UCG-CCS including hydrogen delivery is \$2.11/kg of H_2 and UCG (without CCS) including hydrogen delivery is \$1.78/kg of H_2. The hydrogen production cost without hydrogen delivery from UCG-CCS and

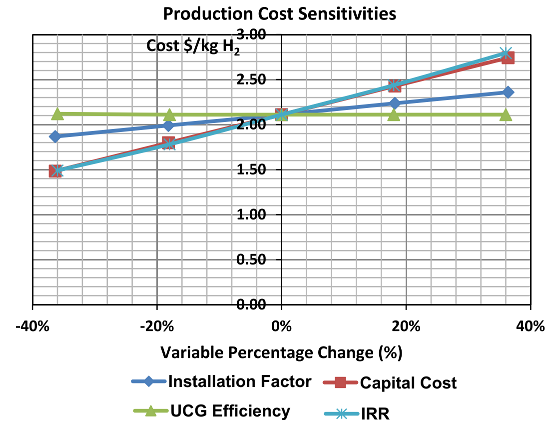

Fig. 8. UCG-CCS hydrogen production cost sensitivities.

UCG are \$1.75/kg of H_2 and \$1.42/kg of H_2 respectively. Thus, it becomes apparent that the additional cost of the hydrogen pipeline has a comparable effect on the UCG production cost as the CCS infrastructure. The sensitivities of key plant parameters on the production cost are shown in Fig. 8. As seen in Fig. 8, the installation factor, and to a greater degree, the UCG efficiency, have a relatively small effect on the price of hydrogen production. Note that the installation factor was only applied to selected plant equipment (see Table 4); hence, its effect is small. The UCG efficiency on the other hand has a relatively miniscule effect on production cost mainly due to the fact that the coal feedstock cost is zero. Thus, the only financial penalty or benefit for an increased/decreased coal to hydrogen efficiency is reflected in the water (steam) consumption of the plant. The water resource cost utilised in this study amounts to \$0.99/m^3 [50]; hence, it has a relatively insignificant effect on the hydrogen production cost. In contrast, the capital cost estimate and the incremental rate of return (IRR) have a significant impact on the cost of hydrogen. The sensitivity of the IRR in particular shows that the viability of UCG-CCS in Alberta will be determined to a great extent by the perceived risks associated with the technology. The current demonstration phase Swan Hills Synfuels plant has proven to be a successful project thus far, with no indication of environmental or other adverse impacts. This project and other similar projects around the world will play a major role in lowering perceived investment risks in the coming years. As investor confidence in the technology is increased, the minimum IRR demanded will likely decrease and hence make UCG-CCS more competitive.

7.5. SMR hydrogen production cost

As seen in Fig. 9, the hydrogen production cost at base case conditions (IRR 10% and natural gas price of \$5/GJ) amounts to \$1.73/kg of H_2 for SMR (without CCS) at Fort Saskatchewan, Alberta and \$2.14/kg of H_2 for SMR-CCS with production at Fort Saskatchewan and CO_2 sequestration at Thorhild, Alberta. At an equivalent IRR to UCG i.e. 15%, these costs amount to \$2.02/kgH_2 and \$2.57/kgH_2 for SMR and SMR-CCS, respectively. Thus, the impact of the IRR on production costs is significant. Intuitively, Fig. 9 also shows that the hydrogen production cost increases linearly as the natural gas price is increased. The sensitivities of other parameters on the hydrogen production cost are illustrated in Fig. 10. It can be seen that the plant capital cost and the IRR are the two most influential parameters on hydrogen production cost (see Fig. 10). However, among all the input parameters, the plant capital cost is the single most influential factor, which is quite intuitive. The IRR is

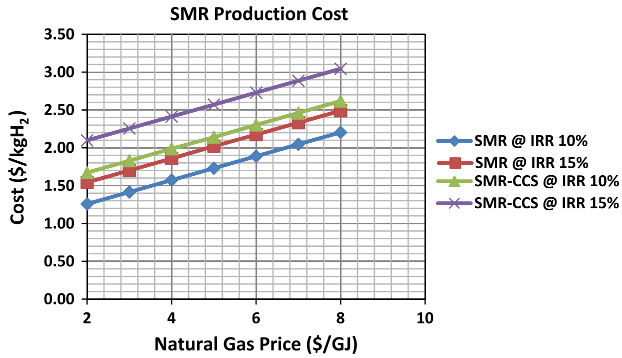

Fig. 9. SMR-CCS hydrogen production costs.

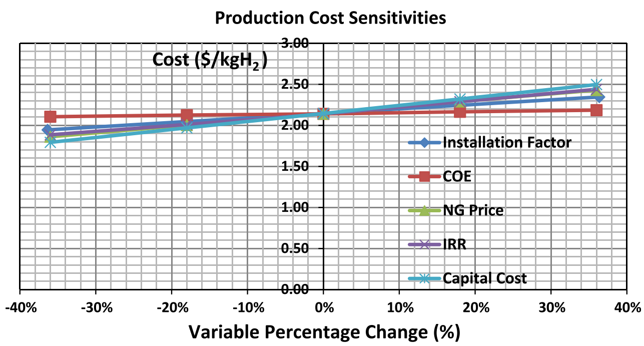

Fig. 10. SMR-CCS hydrogen production cost sensitivities.

closely followed by the natural gas price with regards to the impact on production costs, and the installation factor has an intermediate effect on the production cost compared to other parameters. Finally, the significance of the electricity cost is quite small. This is attributed to the fact that it only applies to the compressor and pump equipment.

7.6. UCG-CCS and SMR-CCS comparative analysis

7.6.1. Production cost scenario comparison

The comparison of production costs between UCG and SMR with and without CCS infrastructure is illustrated in Fig. 11. Furthermore, the seven scenarios considered in this study are also included. It is worth re-iterating that in this study, the IRR for UCG is 15%; while the corresponding value for SMR is 10%. Thus, the results presented in Fig. 11 should be viewed with full consciousness of this IRR differential. The effect of the IRR differential on the competiveness of both technologies is given greater scrutiny in Section 7.6.2

For hydrogen production without CCS, at base case conditions, SMR is the more cost-effective option in comparison to UCG. This remains true for a natural gas price below \$5.30/GJ (see Fig. 11). The reason for this advantage can be attributed to the fact that with SMR, the hydrogen production cost is highly sensitive to the natural gas price and IRR. That being said, the significant natural gas feedstock cost of SMR in comparison to the zero feedstock cost of UCG is offset by the increased investment risk for UCG, as reflected in the 5% IRR differential. Furthermore, a higher initial investment is required for UCG, mainly due to the expensive hydrogen pipeline; this helps to further offset the high feedstock cost of SMR.

However, as seen in Fig. 11, for hydrogen production with CCS, UCG is the more economic option at the base case conditions despite the 5% IRR differential. For SMR-CCS to be competitive, the natural gas price would have to fall below \$4.80/GJ. Furthermore, considering scenario 7, the inclusion of the sale of CO_2 for EOR operations reduces the base case UCG-CCS price from \$2.11 to \$1.61/kg H_2. The selling price of CO_2 utilised in this study for EOR operations is assumed to be about \$47/tonne CO_2 [73,74]. Furthermore, the incremental CO_2 flow rate of the UCG-CCS plant over the SMR-CCS alternative was utilised in the calculation of EOR revenues; so as to accommodate the possibility of EOR CO_2 sales from SMR-CCS. With the inclusion of EOR, the competitiveness of UCG-CCS over SMR-CCS is further enhanced. The natural gas price would have to fall below \$1.55/GJ for SMR-CCS to be the economically superior option. Table 9 gives the cost of hydrogen production for the seven scenarios considered.

7.6.2. Investment risk analysis

The degree of investment risk associated with UCG in comparison to SMR is pivotal in determining the competiveness of both technologies. In this study, the degree of risk of both technologies is assumed to be reflected in the minimum IRR required for investment. The impact of the IRR differential on the competitiveness of both technologies is illustrated in Fig. 12. First, it can be seen in Fig. 12 that at an equivalent IRR (0% differential), UCG with and without CCS is the more economical hydrogen production pathway by a relatively large margin. In the case of hydrogen production without CCS, UCG remains the more cost-effective option up until the IRR differential between both technologies is above 4.6%. For hydrogen production with CCS, the competitive threshold is ex-

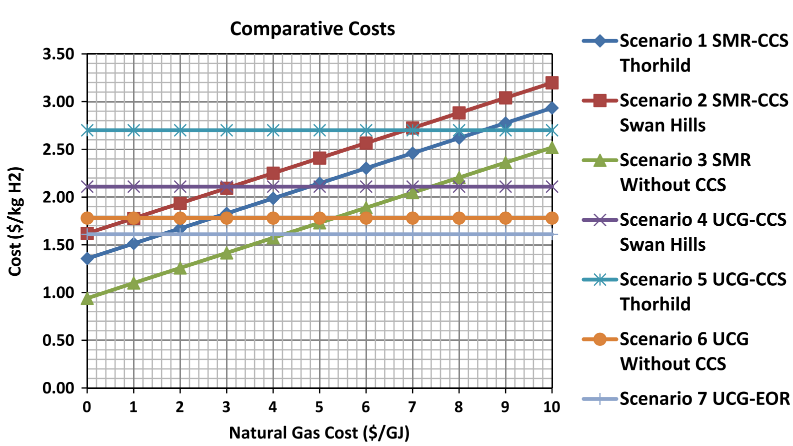

Fig. 11. Hydrogen production cost comparison for scenarios 1–7.

Table 9
Hydrogen production cost for scenarios 1–7.

Scenarios	Description	Hydrogen production cost ($/kg of H_2)
Scenario 1	SMR-based H_2 production at Fort Saskatchewan, Alberta with CO_2 sequestration in Thorhild, Alberta	2.14
Scenario 2	SMR-based H_2 production at Fort Saskatchewan, Alberta with CO_2 sequestration in Swan Hills, Alberta	2.41
Scenario 3	SMR-based H_2 production without CCS	1.73
Scenario 4	UCG-based H_2 production at Swan Hills Alberta, with H_2 delivery to Fort-Saskatchewan, Alberta and sequestration in Swan Hills, Alberta	2.11
Scenario 5	UCG-based H_2 production at Swan Hills Alberta, with H_2 delivery to Fort-Saskatchewan, Alberta and sequestration of CO_2 in Thorhild, Alberta	2.70
Scenario 6	UCG-based H_2 production at Swan Hills, Alberta with H_2 delivery to Fort-Saskatchewan, Alberta without CCS	1.78
Scenario 7	UCG-based H_2 production at Swan Hills, Alberta with H_2 delivery to Fort-Saskatchewan, Alberta and sale of CO_2 for enhanced oil recovery (EOR)	1.61

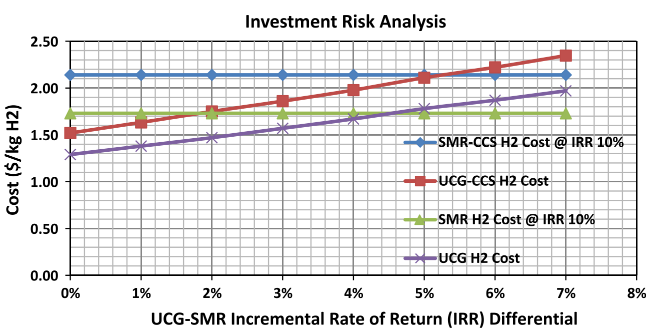

Fig. 12. Investment risk analysis.

tended to an IRR differential above 5.4%. Thus, it becomes apparent that UCG is a financially sound technology particularly for hydrogen production with CCS.

8. Conclusion

From the techno-economic assessment conducted, a number of useful conclusions can be drawn. First, the sensitivity analysis conducted demonstrates that the natural gas price has a significant effect on the competitiveness of the SMR-CCS hydrogen production cost. In the case of UCG-CCS, no fuel costs are incurred. Thus, the profitability risk of the investment with regards to the feedstock cost is non-existent for UCG, and quite significant for SMR. That being said, the feedstock cost volatility risk is counter-balanced by the fact that the technological infancy, environmental risks, and reduced reliability of UCG is greater than its SMR counterpart.

At base case conditions, for hydrogen production without CCS, SMR is the more cost competitive technology relative to UCG; however, for hydrogen production with CCS, UCG is more cost efficient. In particular, the effect of EOR on the competitiveness of UCG-CCS against SMR-CCS at base case conditions is quite significant. At base case conditions, the consideration of potential EOR revenue (scenario 7) from both technologies is the case where the competitive advantage of UCG-CCS against SMR-CCS is highest in magnitude.

The competiveness of UCG against SMR is highly sensitive to the perceived investment risk associated with UCG. If the IRR differential is less than 5.4%, UCG is the more cost effective technology for hydrogen production with CCS; if greater that 5.4%, SMR becomes the more economical pathway. For hydrogen production without CCS, the competitive margin of UCG is reduced to an IRR differential of 4.6%.

Acknowledgements

The authors are grateful to Alberta Innovates – Energy and Environmental Solutions (AI-EES) for financially supporting this research initiative. The authors would like to thank Surindar Singh (AI-EES), Dzung Nguyen (AI-EES) and Eddy Isaacs (AI-EES) for their input and discussion throughout this study. The authors are also thankful to Syrie Crouch and Adrienne lamb of Shell Canada, for their help in providing an industrial benchmark for the analysis carried out.

References

[1] Naterer GF, Fowler M, Cotton J, Gabriel K. Synergistic roles of off-peak electrolysis and thermo-chemical production of hydrogen from nuclear energy in Canada. Int J Hydrogen Energy 2008;33:6849–57.
[2] Energy Resources Conservation Board (ERCB). Alberta's energy reserves 2010 and supply/demand, outlook 2011–2020. ST98-2011; 2011.
[3] Michelse M. Alberta's oilsands: resourceful, responsible. In: Presentation to the University of Alberta Business School. Government of Alberta; 2011.
[4] Wang ZL, Naterer GF. Greenhouse gas reduction in oil sands upgrading and extraction operations with thermochemical hydrogen production. Int J Hydrogen Energy 2010;35:11816–28.
[5] Kapadia PR, Kallos MS, Gates ID. Potential for hydrogen generation from in situ combustion of Athabasca bitumen. Fuel 2011;90:2254–65.
[6] Dunbar RB. Canada's oil sands – a world scale hydrocarbon resource. Strategy West Incorporated; 2009. <http://www.strategywest.com/downloads/StratWest_OilSands.pdf>.
[7] Sarkar S, Kumar A. Biohydrogen production from forest and agricultural residues for upgrading of bitumen from oil sands. Energy 2010;35:582–91.
[8] Utgikar V, Thiesen T. Life cycle assessment of high temperature electrolysis for hydrogen production via nuclear energy. Int J Hydrogen Energy 2006;31:939–44.
[9] Koroneos C, Dompros A, Roumbas G, Moussiopoulos N. Life cycle assessment of hydrogen fuel production processes. Int J Hydrogen Energy 2004;29:1443–50.
[10] Dufour J, Serrano DP, Galvez JL, Moreno J, Garcia C. Life cycle assessment of processes for hydrogen production. Environmental feasibility and reduction of greenhouse gases emissions. Int J Hydrogen Energy 2009;34:1370–6.
[11] Landon S, Smith CE. Energy prices and Alberta government revenue volatility. C.D. Howe Institute Commentary – Fiscal and Tax Competitiveness 2010;313:1–24.
[12] World Energy Council. Survey of energy resources. ISBN: 0 946121 26 5; 2007. <http://www.worldenergy.org/documents/ser2007_final_online_version_1.pdf>.
[13] Friedmann JS, Upadhye R, Kong FM. Prospects for underground coal gasification in carbon constrained world. Energy Proc 2009;1:4551–7.
[14] SwanHills Synfuels. <http://swanhills-synfuels.com/projects/overview/> [accessed 31.10.12].
[15] Burton E, Friedmann J, Upadhye R. Best practices in underground coal gasification. Draft report. Lawrence Livermore National Laboratory, University of California; 2007.
[16] Ag Mohammed AM, Batto SF, Changmoon Y, Chien SC, Choe JI, Cole KR et al. Viability of underground coal gasification with carbon capture and storage in Indiana. Indiana University School of Public and Environmental Affairs; 2011.
[17] Stratus Consulting Inc. Potential environmental impacts of the proposed CIRI underground coal gasification project. Western Cook Inlet, Alaska; 2010. <http://www.csp2.org/reports/

CIRI%20Underground%20Coal%20Gassification%20Report%20-%20Stratus%2027Jan10.pdf>.

[18] Prabu V, Jayanti S. Underground coal-air gasification based solid oxide fuel cell system. Appl Energy 2012;94:406–14.

[19] Hammond GP, Akwe SSO, Williams S. Techno-economic appraisal of fossil-fuelled power generation systems with carbon dioxide capture and storage. Energy 2011;36:975–84.

[20] Intergovernmental Panel on Climate Change. Carbon capture and storage: special report of the Intergovernmental Panel on Climate Change. UK: Cambridge University Press; 2006. p 278–311. ISBN:9780521685511.

[21] Walter K. Fire in the hole: underground coal gasification may provide a secure energy supply and reduce greenhouse gas emissions. Lawrence Livermore National Laboratory; 2007. <https://www.llnl.gov/str/April07/pdfs/04_07.2.pdf> [accessed 17.02.12].

[22] The eco-ENERGY Carbon Capture and Storage Task Force. Canada's fossil energy future – the way forward on carbon capture and storage; 2008. <http://www.energy.alberta.ca/org/pdfs/fossil_energy_e.pdf>.

[23] Bachu S, Stewart S. Geological sequestration of anthropogenic carbon-dioxide in the Western Canada sedimentary basin: suitability analysis; 2002. <http://science.uwaterloo.ca/~mauriced/earth691-duss/CO2_General%20CO2%20Sequestration%20materilas/BachuStewartJCPTCO2.pdf>.

[24] Yee B. Environmental management in Alberta: meeting the challenges of the future. In: Presentation to the University of Alberta Business School, Alberta Environment; 2011.

[25] Alberta Carbon Capture and Development Council. Accelerating carbon capture and storage implementation in Alberta 2009. <http://www.energy.gov.ab.ca/Org/pdfs/CCS_Implementation.pdf>.

[26] Zapp P, Schreiber A, Marx J, Haines M, Hake JF, Gale J. Overall environmental impacts of CCS technologies – a life cycle approach. Int J Greenhouse Gas Control 2012;8:12–21.

[27] Beck B, Garrett J, Havercroft I, Wagner D, Zakkour P. Development and distribution of the IEA CCS model regulatory framework. Energy Proc 2011;4:5933–40.

[28] Figuera D, Fout T, Plasynki S, McIlvried H, Srivastava D. Advances in CO_2 capture technology – the U.S. Department of Energy's Carbon Sequestration Program. Int J Greenhouse Gas Control 2008;2:9–20.

[29] Burton EA, Ezzidine S, Reed J, Beyer JH. Accelerating carbon capture and sequestration projects: analysis and comparison of policy approaches. In: 10th International conference on greenhouse gas control technologies, vol. 4; 2011. p. 5778–85.

[30] Pettinau A, Ferrara F, Amorino C. Techno-economic comparison between different technologies for CCS power generation plant integrated with a sub-bituminous coal mine in Italy. Appl Energy 2012;99:32–9.

[31] Li M, Rao AD, Samuelsen GS. Performance and costs of advanced sustainable central power plants with CCS and H_2 co-production. Appl Energy 2012;91:43–50.

[32] Park SK, Ahn JH, Kim TS. Performance evaluation of integrated gasification solid oxide fuel cell/gas turbine systems including carbon dioxide capture. Appl Energy 2011;88:2976–87.

[33] Yang L, Liu S. Simulation on heat transfer in the process of underground coal gasification. Num Heat Transf Part A: Appl: Int J Comput Methodol 2003;44:537–57.

[34] Seifi M, Chen Z, Abedi J. Numerical simulation of underground coal gasification using the CRIP method. Can J Chem Eng 2011;89(6):1528–35.

[35] Nourozieh H, Kariznovi M, Abedi J. Simulation study of underground coal gasification in Alberta reservoirs: geological structure and process modelling. Energy Fuels 2010;24:3540–50.

[36] Prabu V, Jayanti S. Simulation of cavity formation in underground coal gasification using bore hole combustion experiments. Energy 2011;36(10):5854–64.

[37] Liu S, Li J, Mei M, Dong D. Groundwater pollution from underground coal gasification. J China Univ Mining Technol 2007;17(4):467–72.

[38] Kapusta K, Stanczyk K. Pollution of water during underground coal gasification of hard coal and lignite. Fuel 2011;90(5):1927–34.

[39] Chiesa P, Consonni S, Kreutz T, Williams R. Co-production of hydrogen, electricity and CO_2 from coal with commercially ready technology. Part A: performance and emissions. Int J Hydrogen Energy 2005;30:747–67.

[40] Kreutz T, Williams R, Consonni S, Chiesa P. Co-production of hydrogen, electricity and CO_2 from coal with commercially ready technology. Part B: economic analysis. Int J Hydrogen Energy 2005;30:769–84.

[41] International Energy Agency (IEA). IEA Greenhouse Gas R&D Programme: decarbonisation of fossil fuels. Report PH2/2; 1996.

[42] Shell Canada Ltd. Quest carbon capture and storage project. Directive 65: application for a CO_2 acid gas storage scheme; 2010. <http://www-static.shell.com/static/can-en/downloads/aboutshell/our_business/oil_sands/quest/d65_main_report_app_a_i.pdf>.

[43] Google Inc. Google maps driving distance estimate [accessed 21.04.12].

[44] Beaton A. Coal-bearing formations and coal bed methane potential in the Alberta plains and foothills. Alberta Energy and Utilities Board/Alberta Geological Survey; 2003.

[45] Smith GG, Cameron AR, Bustin RM. Coal resources of the western Canadian sedimentary basin (WCSB). <http://www.ags.gov.ab.ca/publications/SPE/PDF/SPE_004/chapter_33.pdf>.

[46] Swan Hills Synfuels. Presentation at the Alberta innovates energy and environment solution annual technology talk, Calgary, Alberta; November 2011.

[47] Gentzis T, Goodarzi F, Cheung FK, Laggoun-Defarge F. Coal bed methane producibility from the Mannville coals in Alberta, Canada: a comparison of two areas. Int J Coal Geol 2008;74:237–49.

[48] Blindermann MS, Friedmann JS. UCG with CCS: a pathway to a low-cost, low-carbon gas for power generation and chemical syntheses. United States National Energy Technology Laboratory (NETL) 5th annual conference on carbon capture & sequestration; May 2006. <http://www.netl.doe.gov/publications/proceedings/06/carbon-seq/Tech%20Session%20071.pdf>.

[49] Shell Canada Inc. Shell Canada upgrader public disclosure; 2007. <http://environment.alberta.ca/documents/Shell_Upgrader.pdf>.

[50] Jordaan SM. The land use footprint of energy extraction in Alberta. PhD thesis. University of Calgary; 2010.

[51] Bruce GW. Bitumen to finished products. In: Presentation to Canadian Heavy Oil Association technical luncheon, Calgary; 2005. <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BCD005017-90A8-4C01-9F3F-7081E5DF3BC4%7D&documentTitle=5639139>.

[52] Ordorica-Garcia G, Croiset E, Douglas P, Elkamel A, Gupta M. Modelling the energy demands and greenhouse gas emissions of the Canadian oil sands industry. Energy Fuels 2007;21:2098–111.

[53] Olateju B, Kumar A. Hydrogen production from wind energy for the upgrading of bitumen from oil sands. Energy 2011;36:6326–39.

[54] Ogden JM, Yang C, Johnson N, Ni J. Conceptual design of optimized fossil energy systems with capture and sequestration of carbon dioxide. United States Department of Energy (DOE) report. DOE Award No.: DE-FC26-02NT41623; 2004.

[55] Linc Energy Inc. <http://www.lincenergy.com/clean_energy_uzbekistan.php> [accessed 23.04.12].

[56] Williams E, Heidrick T. Economics of hydrogen production from an underground coal gasification (UCG) plant with carbon capture and sequestration (CCS). Alberta Energy Research Institute (AERI), report; 2009.

[57] McCollum DL, Ogden JM. Techno-economic models for carbon dioxide compression, transport and storage & correlations for estimating carbon dioxide density and viscosity. Davis: Institute of Transportation Studies, University of California; 2006.

[58] Crouch S. Personal communication. CCS Sequestration Manager for Shell Canada; December 2011.

[59] Yang C, Ogden J. Determining the lowest-cost hydrogen delivery mode. Int J Hydrogen Energy 2007;32:268–86.

[60] Swan Hills Synfuels. http://swanhills-synfuels.com/projects/iscg/ [accessed 07.11.12].

[61] World Resources Institute (WRI). CCS guidelines: guidelines for carbon dioxide capture, transport, and storage. WRI, Washington, DC; 2008. <http://pdf.wri.org/ccs_guidelines.pdf>.

[62] Heddle G, Herzog H, Klett M. The economics of CO_2 storage. Laboratory for energy and the environment. Massachusetts Institute of Technology (MIT); 2003. <http://sequestration.mit.edu/pdf/LFEE_2003-003_RP.pdf>.

[63] Hendriks N, Wildenborg T, Feron P, Graus W, Brandsma R. EC-Case: carbon dioxide sequestration; 2003-M70066.

[64] International Energy Agency (IEA). IEA Greenhouse Gas R&D programme: transmission of CO_2 and energy; 2002. Report no. PH4/6.

[65] International Energy Agency (IEA). IEA Greenhouse Gas R&D programme: building the cost curves for CO_2 storage: European sector. Report no. 2005/2; 2005.

[66] International Energy Agency (IEA). IEA Greenhouse Gas R&D programme: building the cost curves for CO_2 storage: North America. Report no. 2005/3; 2005.

[67] Parker N. Using natural gas transmission pipeline costs to estimate hydrogen pipeline costs. Davis: Institute of Transportation Studies, University of California; 2004.

[68] Schroeder DW. A tutorial on pipe flow equations. Stoner Associates, Inc; 2001. <http://www.psig.org/Papers/2000/0112.pdf>.

[69] Johnson N, Ogden JA. Spatially-explicit optimization model for long-term hydrogen pipeline planning. Int J Hydrogen Energy 2012;27(6):5421–33.

[70] Government of Alberta (GOA). Alberta oil sands industry quarterly update: December 12th 2009–March 5th 2010. <http://www.albertacanada.com/documents/AOSID_QuarterlyUpdate_Spring2010.pdf>.

[71] Molburg JC, Doctor RD. Hydrogen from steam methane reforming with CO_2 capture. In: 20th Annual international Pittsburgh coal conference; 2003.

[72] Lamb A. Personal communication. Senior communications representative for unconventional oil – exploration and production, Shell Canada; December 2011.

[73] United Stated Department of Energy (US DOE), National Energy Technology Laboratory (NETL). Storing CO_2 with enhanced oil recovery. DOE/NETL-402/1312/02-07-08; February 2008.

[74] Kuuskraa VA. Challenges of implementing large scale CO_2 enhanced oil recovery with CO_2 capture and storage. Advanced Resources International Inc.; 2010. <http://web.mit.edu/mitei/docs/reports/eor-css/kuuskraa.pdf>.