Techno-economics of CCS in oil sands thermal bitumen extraction: comparison of CO2 capture integration options

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Abstract

Canada's oil industry is a growing energy source, with proven reserves exceeding 174 billion barrels. The majority of the production is attributable to oil sands. Thermal bitumen extraction is the predominant production method, and is poised to grow at an annual rate of 23% to 2025. This has important long-term GHG emissions implications. To date, CO_2 emissions mitigation efforts have overwhelmingly focused on implementing CCS in bitumen upgrading operations, rather than in thermal bitumen extraction processes. The paper covers the application of CO_2 capture to the main thermal bitumen extraction process: SAGD (Steam-assisted gravity drainage).

The paper presents four SAGD-oxy-fuel integration configurations and compares their techno-economics to a SAGD process featuring natural gas-fired co-generation without CO_2 capture (reference case). Configuration one is a natural-gas fired co-generation boiler retrofitted for oxy-fuel operation. Configuration two is an oxy-fuel fluidized boiler using bitumen as fuel. The third configuration features a natural gas oxy-fuel boiler integrated with a cryogenic Air Separation Unit (ASU). The pressurized "waste" N_2 is expanded in a turbine with additional heat integration. The fourth configuration features natural gas oxy-combustion with O_2 from an Oxygen Transport Membrane (OTM) unit. Other integration concepts, including Chemical Looping combustion (CLC) are introduced. Because these concepts are in an earlier stage of development, the discussion covers their qualitative aspects and potential benefits over the previously mentioned cases.

Keywords: Oil sands; Oxy-fuel; Integration; Techno-economics; bitumen; SAGD; Canada;

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1. Introduction

In 2011, Canada ranked as the sixth largest oil-producing country in the world, totalling 3.02 million barrels per day (bpd). Over half of this production was derived from oil sands. The growth outlook for the sector is fairly robust, increasing from 1.6 million bpd in 2011 to 3.1 million bpd in 2020 and anticipated to reach 4.2 million bpd by 2025, representing an annualised growth rate of 19% (CAPP, 2012). Bitumen can be extracted from oil sands either by mining (surface) or thermal extraction (underground) techniques. The former involves excavating surface deposits, followed by hot water processing to separate bitumen from the sand. Thermal bitumen extraction (also known as in-situ) via steam-assisted gravity drainage (SAGD) is the other method. In SAGD, two horizontal wells are drilled into the underground oil sands reservoir. Steam is injected through the upper well, heating up the bitumen via condensation and thus lowering its viscosity. The bitumen flows by gravity to the lower well, where it is collected and pumped with the condensate to the surface for further processing.

Although currently, bitumen production from both methods is roughly equal, production from SAGD is forecasted to substantially ramp-up, surpassing mining production by a wide margin. Between 2010 and 2025, SAGD production is expected to rise at an annual rate of 23%, compared to 15% for mining and 12% for bitumen upgrading (CAPP, 2012). Due to the large fossil energy intensity of oil sands operations, this situation has important GHG emissions implications.

Figure 1 shows the breakdown of estimated CO_2 emissions associated with forecasted oil sands operations, to the year 2025. The estimates are based on current practices for bitumen mining, SAGD, and upgrading operations in Alberta, Canada, and largely follow the methodology of previous studies on the subject (Ordorica-Garcia et.al, 2010, Ordorica-Garcia, 2007). In a business-as-usual scenario, CO_2 production associated with oil sands operations would increase by a factor of 2.5 within 15 years, from 2010 levels. By 2025, total CO_2 emissions could reach 250 kilotonnes a day, or 91.2 megatonnes a year.

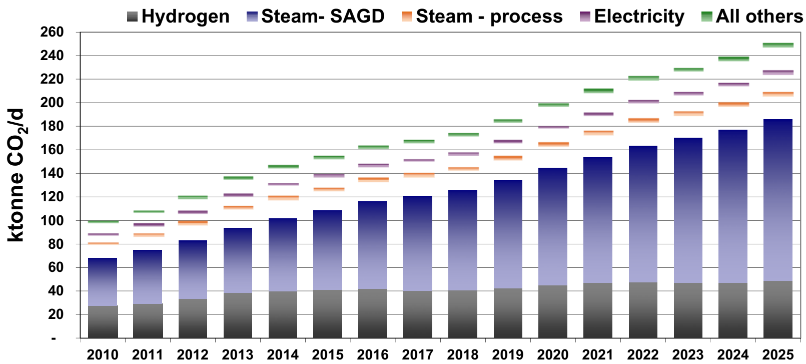

Figure 1. Oil sands CO2 emissions by source 2010-2025

In the absence of major technological breakthroughs, the majority of the CO_2 emissions from oil sands are expected to come from steam generation processes for thermal bitumen extraction via SAGD. In the forecast presented in Figure 1, steam production for use in SAGD accounts for 55% of the total CO_2 emissions, followed by hydrogen production for bitumen upgrading at 19%.

Presently, commercial SAGD operations typically produce “wet” steam in gas-fired once-through steam generators. The steam required per barrel of bitumen is given by the steam-to-oil ratio (SOR), usually ranging from 2 to 5. A conservative SOR of 2.5 was used in this study. The higher the SOR, the higher the CO_2 emissions per barrel of bitumen produced.

To date, most CCS initiatives within the oil sands sector have focused on bitumen upgrading operations. This work proposes that GHG mitigation efforts for SAGD processes should assume greater importance, as the latter are likely to be the leading source of CO_2 in the foreseeable future. Also, CCS implementation in SAGD operations presents a number of unique challenges. First, most SAGD producers are relatively small, compared to upgrading operations. Second, they are often geographically dispersed, whereas upgraders exist predominantly in only two locations. Third, they generate flue gas with a lower CO_2 concentration than that of hydrogen plants, the main source of CO_2 in upgrading operations. Hence, the optimal options for capturing CO_2 from upgrading operations are likely to be sub-optimal for SAGD processes, which demand a different approach.

In a previous study [1] the authors evaluated several CO_2 capture implementation options for oil sands operations. The study concluded that oxy-fuel combustion is the most suitable option for integrating CO_2 capture in SAGD in the short term. Oxy-fuel combustion is fed with pure O_2, instead of air to the combustion process. O_2 is diluted with recycled flue gas (RFG) for controlling the operation temperature. Flue gas will contain mostly CO_2, and water vapour. The resulting exhaust gas stream after drying is a highly concentrated CO_2 flow, for the later treatment, compression and storage.

Oxy-fuel combustion can be feasibly applied to steam boilers, which are the chief source of GHG emissions in SAGD operations. Existing boilers could be retrofitted or replaced by new oxy-boilers. Adding post-combustion capture downstream of the boiler is another option. This is less attractive than oxy-fuel because it would require large quantities of low-grade steam for solvent regeneration, in addition to the high-quality steam required for SAGD. For retrofits, an existing once-through boiler would be unlikely to have extra-steam capacity, while bleeding off high quality steam to make low-grade steam. Thus, supplemental steam generation facilities would be required, in addition to the capture plant.

Pre-combustion technology is not a good fit for SAGD operations because it would involve separating the combustion and capture processes. This would mean that, after CO_2 recovery downstream of a gasification process, extra CO_2 would be generated in the boiler due to syngas combustion at atmospheric pressure, requiring more capture downstream of the boiler. The latter would largely negate the advantage of capturing CO_2 upstream of the boiler at high pressure and concentration.

The aim of the study is to provide a preliminary techno-economic evaluation of four options for integrating oxy-fuel combustion into SAGD operations. The proposed approaches are compared in terms of CO_2 mitigation, energy penalties and cost of CO_2 capture. Additionally, novel approaches which are potential longer-term options for economically capturing CO_2 from thermal bitumen extraction operations are discussed.

2. Integration options

2.1. Methodology

Due to its abundance in the region, natural gas is used to produce steam for the SAGD process. This process generates approximately 0.04 tonnes of equivalent CO_2 per barrel of bitumen. The SAGD process also has electricity demands. Since power transport infrastructure is somewhat limited at most SAGD sites, co-generation was assumed in the study. An air-fired SAGD operation is schematized in Figure 2. This represents a baseline case without capture (i.e., business-as-usual), which is compared against all of the proposed concepts.

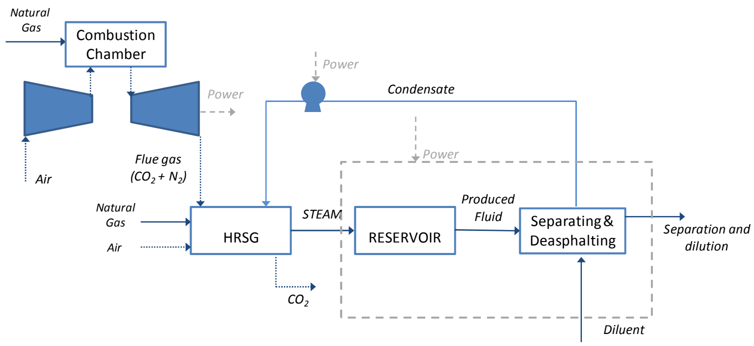

Figure 2. Baseline Case: Air-fired SAGD without CO2 capture

In the study, CO_2 generated by the SAGD process is captured applying oxy-fuel combustion technology. Four different configurations are modeled by means of first-principle mass and energy balances to estimate their emissions, energy and economics. The key assumptions, common for all cases are summarized in Table 1.

Table 1. Key study assumptions and parameters

Parameter	Units	Value
SAGD bitumen extraction capacity	bbl/day	100,000
Steam-to-oil ratio (SOR)	-	2.5
SAGD steam conditions	kPa/ºC	8,000/300
SAGD electricity consumption	kWh/bbl	3.4
ASU electricity consumption	kWh/t O_2	220
Compression train electricity consumption	kWh/t CO_2	100
O_2 concentration at combustor inlet	%	30
Natural gas LHV	kJ/m^3	35,000
Bitumen LHV	kJ/kg	40,335
Bitumen carbon content	%	83.5
Steam boiler efficiency	%	90
Steam cycle efficiency	%	40
Gas turbine efficiency	%	33

The bitumen extraction rate is set up as the initial input from which the required steam production is estimated. The energy required for steam generation is then calculated along with the electricity demands of the process. The fuel is natural gas in all cases but one, which uses indigenous fuel (i.e., bitumen). Bitumen is difficult to burn in conventional boilers, so fluidized bed technology was modeled instead.
All concepts need extra electricity to separate oxygen from air and to compress CO_2 for transport and storage. At the time of writing, it was generally acknowledged that cryogenic Air Separation Units (ASU) were the only commercial means of producing the large amounts of O_2 required for oxy-fuel. The value of 220 kWh/t is recommended by the IPCC [2] as a realistic ASU consumption. New approaches for O_2 separation, such as membrane-based ones, aim to reduce the capture energy penalty by replacing the cryogenic ASU. The former option is also assessed in this study.

2.2. Case 1: Natural gas oxy-fuel boiler

In Case 1, the SAGD process is retrofitted with oxy-fuel capture technology. Electricity is generated in a natural gas turbine fired with oxygen and recycled flue gas (RFG), which is mostly CO_2. The sensible heat from the gas turbine exhaust gas is recovered in a heat recovery steam generator (HRSG). As shown in Figure 3, the HRSG is oxy-fired to produce the balance of the steam needed for the SAGD process. Oxygen is produced in a cryogenic ASU and diluted with RFG. Electric power requirements are represented with discontinuous line in Figure 3. The CO_2 is compressed to increase its density and to be ready for transport and/or storage.

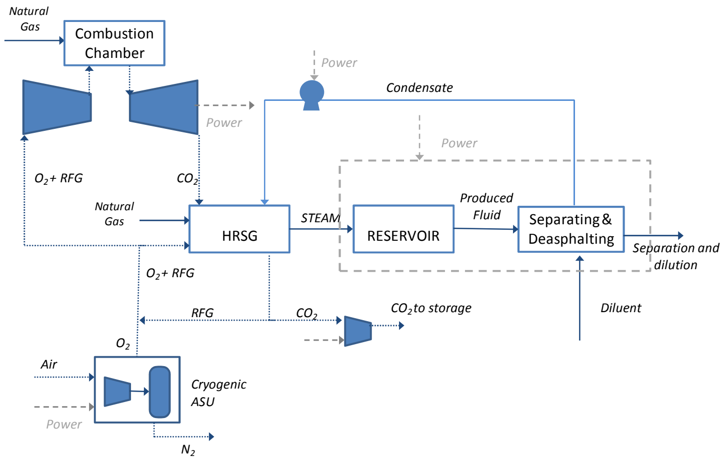

Figure 3. Case 1: SAGD with Oxy-fuel natural gas boiler integration

2.3. Case 2: Oxy-fuel fluidized bed boiler with indigenous fuel (bitumen)

The fuel used for steam generation is a significant component of the operating costs of the SAGD process. Although currently, natural gas prices are low, this has not always been the case; prices are anticipated to rise to historical averages, eventually. This is the motivation behind Case 2: the use of on-site bitumen, an indigenous fuel, instead of natural gas. The representative flow-sheet is presented in Figure 4. In this concept, the boiler needs to be capable of burning high-viscosity liquid bitumen. The fluidized bed boiler technology can handle several fuels. Liquid fuels combustion in fluidized beds has been demonstrated by different researchers. Fuel cracking, bed agglomeration and the blocking of the injectors are the main operational challenges currently under investigation [3-4]. Bitumen could also be blended with local biomass resources in the form of pellets, lowering further the net CO_2 emissions of the process [5].
Case 2 is a greenfield plant featuring a bitumen fluidized bed boiler, fired with O_2 from a cryogenic ASU and RFG. The boiler generates steam at 12,000 kPa and 540ºC. After expansion in a HP turbine, part of this steam is sent to the SAGD process, and the rest is expanded in a secondary steam turbine for additional power generation. This arrangement allows the possibility of generating all the power needed for the SAGD process and for the ASU and CO_2 compression train.

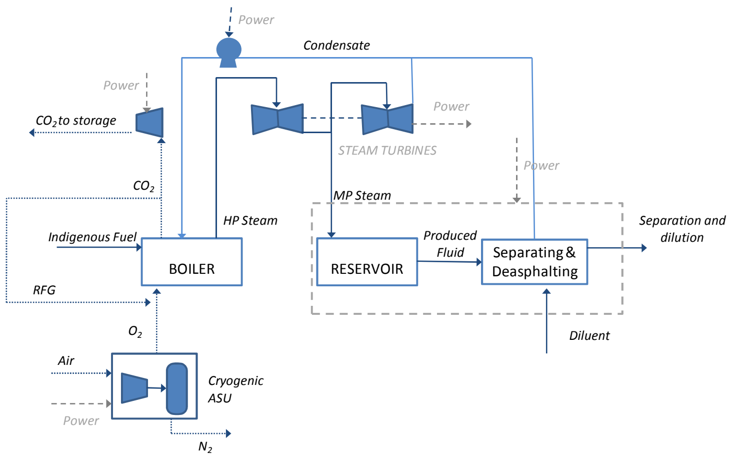

Figure 4. Case 2: SAGD with bitumen-fired oxy-fuel fluidized bed boiler integration

2.4. Case 3: Integration of the waste N_2 from the ASU

This concept is based on the oxy-fuel integration scheme proposed by Tranier et al. [6]. It is largely the same as Case 1, except that in Case 3, the pressure of waste nitrogen from an advanced ASU is 500 kPa. The N_2 temperature is further increased to 650ºC in the oxy-fuel boiler, the gas is expanded in a turbine, generating electricity and thus, offsetting the energy penalty of the ASU. This scheme is represented in Figure 5. Case 3 features extensive heat integration, which includes cooling the nitrogen from outlet of the nitrogen turbine by producing extra steam for the SAGD process, lowering the natural gas demand.
Due to the complexity involved with modifying boiler internals to enable the required heat transfer, this concept is assumed to be limited to new SAGD builds, as opposed to retrofit applications.

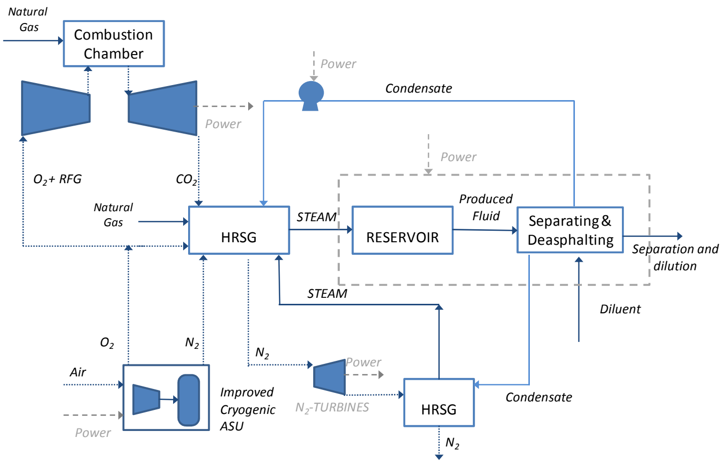

Figure 5. Case 3: SAGD with oxy-fuel natural gas boiler with ASU integration

2.5. Case 4: Integration of an oxygen transport membrane

Cryogenic air separation is currently the only feasible technique for producing oxygen industrially, at the scale required for oxy-fuel combustion. However, other novel membrane-based technologies offer strong potential benefits when integrating oxy-fuel and SAGD. Case 4 uses a configuration based on Oxygen Transport Membrane (OTM) technology, as shown in Figure 6. OTM is based on dopped Zirconia and it claims energy consumption as low as 75% of that of a cryogenic ASU [7]. Case 4 is based on the oxy-fuel proposal by Bredesen et al. [8]. In their scheme, the combustion takes place in a pressurized OTM, so that flue gas can be expanded in a gas turbine and further cooled down in a HRSG. If applied to SAGD, this concept would produce surplus electricity. The transmission infrastructure to take advantage of excess generation is limited in the oil sands region. Hence, the concept proposed here produces steam at high pressure and temperature, which is expanded in a steam turbine, bleeding the required steam to the SAGD process and thus minimizing excess electricity production.

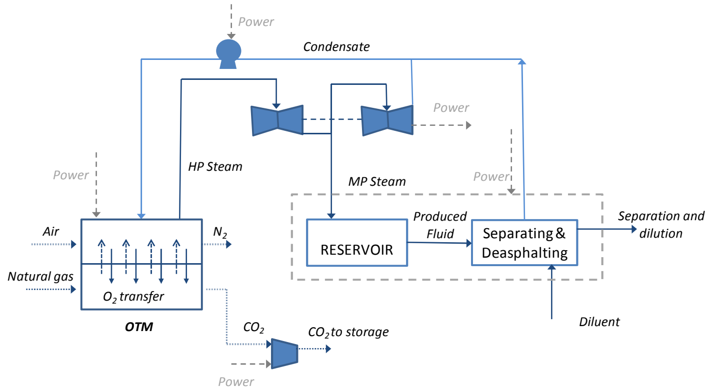

Figure 6. Case 4: SAGD with oxy-fuel OTM integration

3. Results and discussion

In this section the four configurations are examined, comparing three main features of CCS systems integration: the CO_2 emissions, the energy requirements and the economics. The initial parameter for drawing up the following results is the production of 100 000 barrels of bitumen (Table 1). Hence, the results can easily be extrapolated to specific units.

3.1. CO_2 emissions comparison

Table 2 summarizes the estimated CO_2 emissions for all cases. The first column shows total CO_2 production. Case 2 CO_2 production is remarkably higher than the rest. The cause is twofold: the lower thermal efficiency of the steam cycle for power generation and the carbon intensity of bitumen-fuel. The former occurs in the OTM configuration (Case 4). A portion of the CO_2 is linked to the energy demands of the capture process, which is represented in the second column of Table 2, as a percentage of total CO_2 production. The CO_2 emissions associated with O_2 production by means of OTM are around 65% less than ASU case.

Table 2. CO_2 emissions comparison

Case ID	Configuration	CO_2 emitted (kg/s)	CO_2 attributable to capture process (%)
Baseline	No CO_2 capture	3.95	0
1	Natural gas oxy-fuel	0.39	20.9%
2	Bitumen oxy-fuel	0..73	25.3%
3	N_2 integration	0.41	22.31
4	OTM integration	0.51	16.2%

CO_2 avoided assumed 90% of CO_2 separation efficiency. When divided per unit of fuel, the higher emissions of some process are compensated by the higher combustion energy, like in the case of burning indigenous fuel.

3.2. Energy demands comparison

Energy penalty is one of the main drawbacks of all CO_2 capture techniques integrated into power generation systems. However, system energy efficiency, understood as electricity generation per fuel input, is not a practical parameter in the current study, since electricity is not the final product. Instead, the energy efficiency is defined here as:

$$\eta\ (\%) = \frac{Product}{Input} = \frac{Energy\ in\ steam\ to\ SAGD\ [MW]]}{Fuel\ [MW]} \tag{1}$$

The results of the energy balances of the different systems are shown in Table 3. Electricity generation corresponds to the system demands.

Table 3. Comparison of energy requirements

Case ID	Configuration	Fuel input (MW_{th})	Electricity generation (MW_e)	Electricity for capture & compression (MW_e)	η (%)
Baseline	No CO_2 capture	76.44	14.17	0	45.5%
1	Natural gas oxy-fuel	77.24	17.90	3.74	45.0%
2	Bitumen oxy-fuel	95.64	18.96	4.8	36.4%
3	N_2 integration	78.38	17.01	3.79	44.4%
4	OTM integration	90.00	16.86	2.69	38.6%

The two cases involving steam turbine power generation (Cases 2 and 4) require higher fuel input rates, due to their lower overall steam generation efficiencies. The integration of N_2 from ASU (Case 3) do not offer gains when electricity generation is not the product, as in the original concept. The reason is the "use" of thermal energy required for process steam, on heating up the N_2 for its expansion.

The energy penalties, observed from last column, are not comparables with the energy penalties in power plants. In general, the efficiency penalty of oxy-fuel capture in a coal power plant, is estimated around 10%. In our case though, the penalties calculated with (1) associated to CO_2 capture, exhibit no great significance.

3.3. Economics comparison

An common method for estimating the cost of CO_2 avoidance in power generation calculates the ratio between the increment of the cost per kWh due to capture and the decrease of CO_2 emitted per kWh [9]. In this study, we adapt the method by measuring the changes on a per-barrel of bitumen basis. The calculation of the avoided CO_2 cost then becomes:

$$CO_2\ avoidance\ cost = \frac{SAGD\ energy\ cost_{w/capture} - SAGD\ energy\ cost_{w/o\ capture}\left[\frac{\$}{bbl}\right]}{CO_2 emissions_{w/o\ capture} - CO_2 emissions_{w/\ capture}\left[\frac{tonne}{bbl}\right]} \quad (2)$$

The energy costs include the annual capital and O&M costs to supply all the steam and electricity required by the SAGD process with and without capture. Capital costs cover only the equipment required to produce steam and electricity and capture and compress CO_2. The capital associated with the SAGD process itself (wells, separation, dilution, etc.) is excluded, as it is common to all the cases. Capital costs are considered overnight costs only, and thus they exclude land costs, insurance, taxes, etc. Operating costs include labour, maintenance and fuel consumption. The main economic assumptions used in the analysis are listed bellow [9-12]:

- capital cost of conventional ASU: 500 $/kW
- cost of electricity production with gas turbine: 4.8 c$/kWh
- cost of electricity production with steam turbine: 6 c$/kWh
- cost of oxygen production membrane: 350 $/kW
- existing process is retrofitted and it is considered paid off
- 20 year project life with zero salvage value at the end of the project.
- no taxation or depreciation calculations are included
- hours of operation: 8000 h/year.
- maintenance costs: 2.2% of the fixed capital investment
- natural gas price: 4.8 $/GJ
- indigenous fuel price: $1.5/GJ

Table 4 summarises the estimated costs for all cases. CO_2 avoidance costs are calculated using Eq. 1. Our estimated availability of the technology concepts is also given as near- medium- or long-term. This is an important qualifier because some of the approaches presented here have not been proven at a commercial scale yet. Finally, a list of the key extra units required by each of the configurations is given in Table 4.

There are two notable techno-economic uncertainties influencing the results. On the one hand, the cost of large-scale O_2 production by membranes is difficult to predict. In our estimates, a cost reduction of 35% with respect to a cryogenic unit has been assumed [13]. On the other hand, establishing the cost of indigenous fuels is not straightforward. Our calculations assumed a value roughly one-third that of natural gas price, or $1.5/GJ. This value is particularly relevant. If bituminous fuel, such as asphaltenes could be considered cost-free because availability reasons, the cost of CO_2 avoided would drop to only $14/tonne. Although currently few SAGD operators separate asphaltenes from bitumen prior to shipping it, once removed, it is stockpiled because there is no practical use for it.

The integration of the N2 turbine does not offer also an economical advantage, because certain increase on capital cost with respect to the Case 1 results.

Table 4. Cost comparisons

Case ID	Configuration	Capital cost ($/bbl)	O&M cost ($/bbl)	CO_2 avoidance cost ($/tonne CO_2)	Expected availability	Additional equipment*
Baseline	No CO_2 capture	-	0.261		Current	N/A
1	Natural gas oxy-fuel	0.177	0.302	71	Near	ASU
2	Bitumen oxy-fuel	0.234	0.170	51	Near	ASU + SC
3	N_2 integration	0.180	0.306	73	Medium	ASU + GT_{N2} + $HRSG_{N2}$
4	OTM integration	0.188	0.347	92	Long	OTM + ST

* ASU: Air separation unit, GT: gas turbine, HRSG: heat recovery steam generator, SC: steam cycle, ST: steam turbine

Novel approaches for capturing CO2 with reduced energy penalty are currently under development. One of these technologies is chemical-looping combustion (CLC). In this process, a metal oxide transfers the oxygen from the combustion air to the fuel, with no need of additional Air Separation Unit. Integration of CLC in SAGD operations appears to be advantageous as it could offer important cost reductions and is well-suited for steam generation (Ordorica-Garcia et al., 2012). Key techno-economic uncertainties for this outlook include the oxygen carrier costs and longevity, as well as successfully demonstrating the technology with gaseous fuel.

Carbonation-calcination looping process is based on interconnected fluidized bed reactors, similarly to CLC. The former takes advantage of the carbonation of a low sorbent, such as calcined limestone. The formed calcium-carbonated is calcined in the second reactor. Calcination requires high temperature, and this energy can be obtained by means of in-situ oxy-fuel combustion [14]. Extra-steam could be thus produced for SAGD or even for a new steam turbine for electricity generation.

4. Conclusions

In this paper, the integration of oxy-fuel combustion with the SAGD process has been explored. Four concepts have been modeled, to provide an initial estimate of their techno-economic performance.

There is not a unique optimum configuration scheme, since the different criteria must be taken into account. Unlike the power generation plants with CCS, the SAGD process is a high electricity-demand process. This allows the additional power requirements from ASU and compression not being so decisive on the overall energy balance of plant. Attending to the three main criteria of CO_2 emissions per fuel, energy requirements and cost of tone CO_2, the configuration the simplest configuration with oxy-fuel gas turbine with steam co-generation is the most convenient, regarding capital costs and efficiency penalties. The oxygen production membranes are an interesting option for energy savings and probably the cost will be reduced in the following years. The OTM integration option evaluated in this study is arranged using steam turbine. Energy savings are then far from compensating the extra cost of tone CO_2. Optimum configurations involving membranes are integrated with gas turbines cycles and so, energy parameters show more favorable numbers. In the case of SAGD, however, a great gas turbine is not an option, since electricity lines for transport are unavailable. The fuel prices uncertainties gives an open door to a considerable reduction of CO_2 capture per barrel, for using low cost bitumen-derived fuels.

Novel approaches based on interconnected reactors will be interesting options in the following years if they reach the commercial scale deployment.

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