Energy Policy ∎ (∎∎∎∎) ∎∎∎–∎∎∎

Contents lists available at SciVerse ScienceDirect

Energy Policy

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

Evaluating the role of cogeneration for carbon management in Alberta

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ARTICLE INFO

Article history:
Received 15 November 2010
Accepted 24 September 2011

Keywords:
Oil sands
Cogeneration
Carbon management

ABSTRACT

Developing long-term carbon control strategies is important in energy intensive industries such as the oil sands operations in Alberta. We examine the use of cogeneration to satisfy the energy demands of oil sands operations in Alberta in the context of carbon management. This paper evaluates the role of cogeneration in meeting Provincial carbon management goals and discusses the arbitrary characteristics of facility- and product-based carbon emissions control regulations. We model an oil sands operation that operates with and without incorporated cogeneration. We compare CO_2 emissions and associated costs under different carbon emissions control regulations, including the present carbon emissions control regulation of Alberta. The results suggest that incorporating cogeneration into the growing oil sands industry could contribute in the near-term to reducing CO_2 emissions in Alberta. This analysis also shows that the different accounting methods and calculations of electricity offsets could lead to very different levels of incentives for cogeneration. Regulations that attempt to manage emissions on a product and facility basis may become arbitrary and complex as regulators attempt to approximate the effect of an economy-wide carbon price.

1. Introduction

The various carbon emissions management policies being discussed or adopted around the world create a unique set of experiments in policy, engineering and economic pricing. All else being equal, an economically efficient policy should create a single economy wide marginal carbon price signal either in direct form, such as a carbon tax, or in an implied form such as a cap and trade system. In either case the objective is to influence energy sector investment and decision-making so as to cost-effectively restrain emissions. Of course, restraining emissions is but one objective of government policy; and, there may be sensible reasons to deviate from economy-wide approaches. If, for example, there is reason to believe that imposing a relatively high carbon price will spur technical innovation in a particular sector lowering the future cost of emissions abatement so substantially as to make up for the short-term loss of economic efficiency.

Theory aside, in most cases policy makers have opted to use complex facility or product-based policy tools that reflect political pressure against enacting efficient economy-wide carbon policies. Enforcement of such policies requires emissions accounting methods that are data and management intensive. Furthermore, choice of facility- or product-based carbon accounting methods is inherently arbitrary in the sense that there are no simple general rules for producing emissions estimates which (a) produce stable results and (b) are self-consistent in the sense that the total emissions from a set of facilities are independent of the way the rules are applied. This arbitrariness can be an impediment to academic assessment of life cycle emissions, but when such emissions calculations are used as part of policy then one can expect rational profit-seeking firms to exploit the arbitrariness to reduce their burden under the emissions control policy.

In this paper we examine emissions rules for oil sands producers in the Canadian province of Alberta, as an example of a case where uncertainty in emissions accounting and the burden of administrative complexity have interacted to frustrate efficient carbon policy. These concerns are particularly relevant for a facility with multi-product outputs, such as a cogeneration facility that produces both electricity and steam for bitumen production.

Oil sands operations in Alberta are playing an increasingly important role in North American oil supplies and Canada's oil export market. Production of bitumen, the primary hydrocarbon extracted from oil sands, reached approximately 1.3 million barrels per day in Alberta in 2008, satisfying approximately 1.6% of world demand of oil (EIA, 2008; ERCB, 2009b). Bitumen

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doi:10.1016/j.enpol.2011.09.051

recovery and processing requires a significant amount of thermal energy and electricity (ERCB, 2009b). Natural gas is the main fuel currently used to satisfy the thermal energy demand of oil sands operations. In 2003, the volume of natural gas purchased from Alberta's gas market for the purposes of bitumen recovery and upgrading amounted to 5.2 billion cubic meters, roughly 5% of Canadian demand and 14% of demand in Alberta (ERCB, 2009b). The high energy intensity of oil sands operations combined with the fact that the primary energy sources used to generate heat and electricity are predominantly fossil fuels, results in relatively high greenhouse gas (GHG) emissions from this sector. It has been reported that the oil sands sector contributed approximately 5% of Canada's emissions resulting in 37.2 million tCO2 equivalent (tCO2 *eq.*) in 2008. This is a 39% growth from the oil sand sector's GHG emissions in 2000 (Environment Canada, 2010).

Cogeneration, the combined generation of electric power and thermal energy, provides an option for oil sands operations to meet both steam and electric energy demands onsite. Though various configurations are possible, oil sands operations typically use a gas turbine to generate power coupled with a heat recovery steam generator (HRSG) that captures waste heat from the gas turbine exhaust to produce steam or hot water (LeBlanc et al., 2005a). Despite higher onsite fuel use, cogeneration has a high operating efficiency, on the order of 70–80%, compared to standalone steam and electricity production. The primary requirement to justify the incorporation of a cogeneration system is the presence of a steady thermal energy demand. Due to the substantial heat requirements in oil sands operations, electricity production of a cogeneration system incorporated into an oil sands operation typically exceeds the onsite demand, which may result in electricity exports to the Alberta grid. Alberta's electricity sector, where the generation is dominated by coal and natural gas, produced 52 million tCO2 in 2008 making it the most carbon intensive power system in Canada (Environment Canada, 2010). In 2008 the combined GHG emissions of Alberta's oil sands sector and the electricity sector amounted to 37% of the province's 244 million tCO2 *eq.* emissions. The growing oil sands sector has the potential to increase its cogeneration capacity, potentially displacing higher carbon intensive electricity in the electricity sector of Alberta.

In this paper we examine the use of cogeneration for oil sands operations in the context of carbon emissions management. Our main objectives are to: (1) assess the role of cogeneration for carbon emissions reduction in Alberta; (2) investigate the effect of present GHG emissions reduction regulation in Alberta on the economics of cogeneration; (3) evaluate the efficiency of current and alternative emissions control policies; and, (4) examine the way in which uncertainties of facility or product-based carbon accounting complicates efficient carbon policy.

2. Background

2.1. Oil sands operations

The proven oil sands reserves in Alberta are estimated at 170 billion barrels of crude bitumen. In 2006, Alberta's oil sands were the source of about 62% of the province's total crude oil (and equivalent) production and about 47% of all crude oil (and equivalent) produced in Canada. Forecasts of bitumen production growth are as high as 3 million barrels per day by 2020 and up to 5 million barrels per day by 2030 (EIA, 2008).

Oil sands operations consist of extracting bitumen and in some cases upgrading that into synthetic crude oil. Both phases need a substantial amount of energy, the amount of which depends on extraction technology, among other things. Currently, the principal extraction technologies in use can be categorized as surface mining and in situ extraction techniques (ACR, 2004). The former removes the oil sands by mining and extracts the bitumen through a series of processes utilizing thermal energy and water. The latter involves drilling wells and injecting steam to reduce the viscosity of bitumen so it can be pumped to the surface. The two main thermal in situ techniques that are in commercial use are "cyclic steam stimulation (CSS)" and "steam assisted gravity drainage (SAGD)". Short to medium term bitumen production growth is forecasted to occur mainly using mining and SAGD extraction technologies (ERCB, 2009b). The energy demands for bitumen extraction and upgrading are listed in Table 1.

Table 1
Electricity and natural gas demand for bitumen extraction and upgrading (LeBlanc et al., 2005a; Moorhouse and Peachey, 2007).

Process	Natural gas (GJ/bbl bitumen)	Electricity (kW h/bbl bitumen)
Extraction:		
Mining	0.3–0.4	14–16
In situ	1–1.6	1–15
Upgrading	0.15–0.45	14–55

A reliable supply of electricity and thermal energy is critical for both bitumen extraction technologies. Currently, all mining and upgrading projects that are in commercial operation have incorporated cogeneration while only 6 out of 25 commercially operating in situ extraction projects (including both SAGD and CSS) have installed cogeneration systems. However, those six projects represent approximately 65% of the total in situ bitumen extraction (ERCB, 2009a). The installed cogeneration capacity in mining and upgrading operations amounted to 1430 MW in 2008 that generated 8567 GW h of electricity of which 76% was consumed onsite. Thermal in situ production had 760 MW of installed capacity and generated 2205 GW h in 2009, of which 43% was consumed onsite (ERCB, 2009b).

According to a recent survey, the factors that are critical in an oil sands operators' decision to invest in cogeneration include capital costs, the price of natural gas and electricity, security and reliability of electricity supply, environmental performance of the operation, present and future GHG control regulations, and cost and availability of transmission (OSDG, 2010). The same survey reports a tendency to delay the cogeneration investment and also size capacity sufficiently to satisfy only the host facilities electricity demand in light of uncertainty associated with the factors listed above.

2.2. Alberta electric power system

Alberta's electric power system had 12,142 MW of installed generation capacity in 2007, which produced 69,213 GW h of electricity. Coal-fired electricity, currently supplying primarily base load generation, represented 49% of the installed capacity and 64% of total generation in 2007. Natural gas fired electricity (from simple cycle, combined cycle and cogeneration technologies) represented 38% of installed capacity and 29% of total generation in 2007 (AESO, 2009a; ERCB, 2009b). Approximately 75% of the installed natural gas fired generation capacity is cogeneration. The majority of the remaining installed generation capacity consists of renewable generation technologies, including wind, hydro and biomass. The "deregulated" Alberta power system has opened up the generation and retail electricity sales for competition while the transmission system remains regulated. The competitive generation market environment allows cogeneration system operators to sell excess electricity in the Alberta's wholesale electricity market. The transmission links that connect the oil sands regions to the rest of the Alberta grid currently have a maximum import/export capacity of 600 MW. The Alberta

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Electric Power Systems Operator (AESO), however, is planning to expand the transmission capacity serving the oil sands region within next 5–6 years (AESO, 2009b).

Since electricity generation in Alberta is dominated by fossil fuels, particularly coal, the average grid electricity has a very high carbon intensity (approximately 0.84 tCO_2/MW h) compared to the other Canadian provinces. Electricity generation in the province produced 52 million tonnes of CO_{2e} in 2008 which is approximately 21% of Alberta emissions,[1] the largest contribution from a single economic sector in the province (Environment Canada, 2010). The magnitude of emissions, cost of emissions control, and the efficiency of regulation with central and limited ownership make the electric power sector a prime target of GHG emissions reduction targets in Alberta.

The coal generation fraction of the generation base is changing, in part due to natural attrition from planned retirements. Approximately 1100 MW of coal fired generation capacity is expected to retire between 2010 and 2020 (AESO, 2010). Retirement of these units, along with 2–3% forecasted demand growth implies a need for new generation capacity. Thirty-four billion tonnes of discovered coal reserves remain in Alberta, implying that coal could provide a significant source of electricity for many years to come (ERCB, 2009b). However, a stringent carbon control regulation may render conventional coal fired generation uneconomic.

2.3. *Current carbon management policies in Alberta*

The province has set goals to reduce the provincial CO_2 emissions relative to a growing baseline by 50 million tonnes by 2020 and by 200 million tonnes by 2050. The 2050 reduction target represents a 50% reduction below the business as usual level and 14% below 2005 level (AENV, 2008).

In 2007 the Alberta provincial legislature enacted the "Specified Gas Emitters Regulation (SGER)" to regulate GHG emissions. This regulation uses an intensity- and product-based approach. SGER requires facilities in Alberta that have direct annual GHG emissions larger than 100,000 tonnes of CO_{2e} to reduce their emissions intensity by 12% of facility's "baseline emissions intensity (BEI)" (AENV, 2009). Under SGER, the emissions intensity is defined as the GHG emissions per unit economic output of the facility.[2] Facilities that are regulated by SGER can comply by making improvements to their operations; by purchasing Alberta based "offset credits"; by using or purchasing "emissions performance credits (EPC)"; by contributing to the "Climate Change and Emissions Management Fund (CCEMF)" at the rate of C\$15/tCO_{2e}. Facilities that have reduced their emissions intensity by more than the mandatory 12% reduction target are said to have generated EPCs and these credits can be banked for future use or be sold to other facilities. The CCEMF is to be used for projects and new technologies aimed at reducing GHG emissions that originate in Alberta. It should be noted that the SGER implicitly caps the price of carbon in the province at C\$15/tCO_{2e} by allowing compliance through contributions to CCEMF at that rate. The SGER has special provisions for facilities with cogeneration; such facilities are only required to reduce emissions associated with thermal energy production and the emissions attributed to electricity are exempted from SGER compliance target. To calculate this, first the BEI for the facility is set based on the thermal load average over the baseline time period, and then reference baseline emissions are derived by assuming heat was supplied by a hypothetical 80% efficient boiler.[3] The "net emissions intensity (NEI)" of the facility, in a year where the facility has to comply with SGER, is calculated considering only the emissions associated with thermal energy by subtracting an amount called "deemed emissions attributed to electricity" from the total emissions associated with onsite energy production. Deemed emissions attributed to electricity is calculated by multiplying the amount of onsite cogenerated electricity by the emissions intensity of a natural gas fired CCGT unit, which the SGER guidelines considers to be 0.418 tCO_{2e}/MW h (AENV, 2007, 2009).[4]

3. Model description

In order to assess the potential for CO_2 emissions reductions of cogeneration and the effects of different GHG emissions management policies on the economics of cogeneration, we develop a model based on mass and energy balances of two options that satisfy the steam and electricity demands of a SAGD bitumen extraction operation with a production capacity of 30,000 bbl/day. SAGD extraction is used for this illustrative example for two reasons. First, the steam demand of in situ extraction methods such as SAGD is higher than mining extraction while the electricity demand is lower. Due to the need for a continuous steam supply and the moderate electricity demand, in situ extraction plants have a higher potential to use cogeneration and export electricity to the grid. Second, about 80% of the established crude bitumen reserves are considered to be buried too deep to mine, thus we assume that in situ techniques will be used to extract a larger fraction of the reserves. Of all commercially proven in situ extraction techniques, presently SAGD has the highest growth rate (ERCB, 2009b).

In the first option, electricity demand is satisfied through grid electricity imports, and steam demand is satisfied through an onsite natural gas fired boiler with an 85% higher heating value efficiency (henceforth referred to as *baseline option*; see Fig. 1a). In the second option a cogeneration system is used to produce both electricity and steam (henceforth referred to as *cogeneration option*; see Fig. 1b). It is assumed that the cogeneration system produces excess electricity, which will be sold to the grid and onsite steam demand is satisfied through a combination of the cogeneration system and a supplementary boiler. The cogeneration system consists of a gas turbine and a heat recovery steam generator (HRSG). The HRSG has supplemental firing (also known as duct firing); it can directly fire fuel in addition to recovering heat from gas turbine exhaust to produce steam (Jacobs and Schneider, 2009). The fuel used in both the baseline option and the cogeneration option is natural gas. The parameters assumed for the model are listed in Table 2. Parameters specific to the boilers and the cogeneration system were obtained from the specifications and the test results published by the manufacturers and oil sands industry expert correspondence (MEG Energy, personal communication; Jacobs and Schneider, 2009). Capacities of boilers and cogeneration system were selected to be representative of the typical sizes and conditions that are in use in oil sands operations (MEG Energy, personal communicationLeBlanc et al., 2005b). In order to perform this analysis, we assume that sufficient transmission access is available to export cogenerated electricity to the Alberta electric system. The transmission system

[1] This is approximately 7% of total Canadian emissions.

[2] For example, for a crude oil production facility, GHG emissions intensity is the total GHG emissions per one barrel (or 1 m^3) of oil produced.

[3] The SGER guidelines do not specify whether this is based on a lower or higher heating value (HHV). In our analysis we assumed the baseline boiler efficiency to be 80% in HHV.

[4] Facilities with cogeneration are classified as "stand-alone facilities" and "integrated facilities" and different guidelines are set under SGER to calculate the emissions intensities. A facility is considered as a stand-alone facility if the cogeneration system is the only thermal energy source of the facility and a facility with other thermal energy sources in addition to the cogeneration system is considered as an integrated facility. See AENV (2007) for full details.

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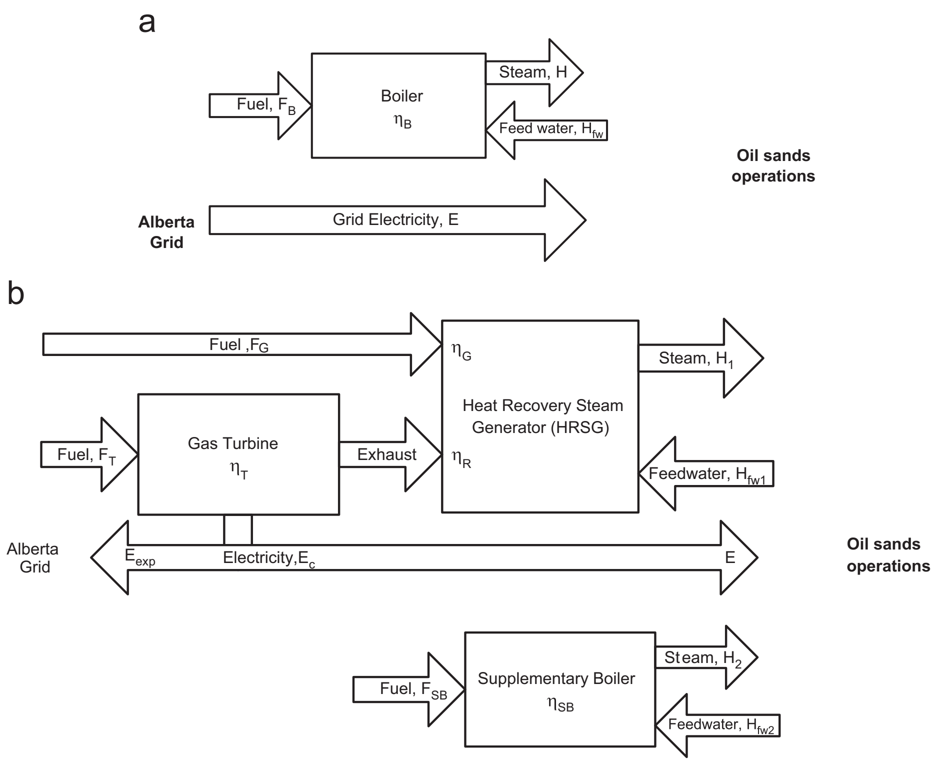

Fig. 1. (a) Baseline option and (b) cogeneration option.

Table 2
Parameters used for the energy and CO_2 emissions calculations.

Parameter	Value
Bitumen production capacity	30,000 bbl/day
Steam demand of bitumen extraction	1.3 GJ/bbl
Electricity demand of bitumen extraction	12 kW h/bbl
Electricity production capacity (cogeneration system)	85 MWe
Maximum steam production capacity:	
Baseline option boiler	1600 GJ/h
Supplementary boiler	500 GJ/h
HRSG (cogeneration system)	1200 GJ/h
Energy conversion efficiencies (HHV basis)[a]:	
Boiler/supplementary boiler, η_B	85%
Gas turbine electricity generation, η_T	30%
HRSG heat recovery, η_R	50%
HRSG supplemental firing, η_G	95%
Fuel carbon intensities (HHV basis):	
Natural gas, I_{cng}	0.05 tCO_2/GJ
Coal, I_{ccoal}	0.1 tCO_2/GJ

[a] A sensitivity analysis was done to investigate the effect of the variations of conversion efficiencies. Through this analysis we found that our conclusions remain unchanged within the reported range of conversion efficiencies.

expansion plan of the AESO supports this assumption (AESO, 2009b). We also assume that the cogeneration system produces electricity and steam at rated capacity. The supplementary boiler is used to meet the steam demand not satisfied by the cogeneration system. The bitumen extraction plant is assumed to be in operation 90% of the time of a given year. The fuel demands of the baseline option (Fig. 1a and the cogeneration option (Fig. 1b) are calculated using Eqs. (1)–(5))

$$F_B = \frac{H - H_{fw}}{\eta_B} \tag{1}$$

$$F_T = \frac{3.6E_c}{\eta_T} \tag{2}$$

$$F_G = \frac{H_1 - H_{fw1} - (1-\eta_T)\cdot F_T \cdot \eta_R}{\eta_G} \tag{3}$$

$$F_{cogen} = F_T + F_G \tag{4}$$

$$F_{SB} = \frac{H - H_1 - H_{fw2}}{\eta_B} \tag{5}$$

where F_B is the fuel input to the baseline boiler (GJ/h), F_T the fuel input to the gas turbine (GJ/h), F_G the fuel input to the HRSG (GJ/h), F_{SB} the fuel input to the supplementary boiler (GJ/h), E_C the electricity produced by the cogeneration system (MW h/h), H the enthalpy of the steam produced by baseline boiler (GJ/h), H_1 the steam produced by cogeneration system (GJ/h), H_2 the steam produced by auxiliary boiler (GJ/h), H_{fw} the baseline boiler feed water enthalpy (GJ/h), H_{fw1},H_{fw2} the HRSG/supplementary boiler feed water enthalpy (GJ/h), η_B the baseline/supplementary boiler efficiency, η_T the electricity generation efficiency of the gas turbine, η_G the HRSG supplemental firing efficiency, and η_R the HRSG heat recovery efficiency.

In this analysis, we only consider the CO_2 emissions from direct fuel combustion for steam and electricity production. Upstream life cycle emissions and the other GHG emissions are excluded from the analysis. The CO_2 emissions from steam production in the baseline option are calculated by multiplying F_B by the CO_2 intensity of natural gas (I_{cng}), assuming complete fuel combustion. The same method is used to calculate the CO_2 emissions associated with the supplementary boiler of the cogeneration option. Estimating total CO_2 emissions of the cogeneration system is straightforward. However, determining the CO_2 emissions associated with electricity alone is not a straightforward calculation as the cogeneration system produces two energy products with a single stream of input fuel. In the realm of life cycle assessment (LCA) studies, this accounting complexity that arise in case of processes with multiple inputs and/or outputs is known as the "allocation problem" (Ekvall, 2001; Guinée, 2002). The theoretical details and guidelines to address the allocation problem, including structured approaches to choose a method to allocate process inputs among outputs, are well studied and published, for example Allen et al. (2009), Ekvall (2001), Guinée and Heijungs (2006), Curran (2007), Gnansounou et al. (2009), Suh et al. (2010), Guinée et al. (2009), Rosen (2008), and Frischknecht (2000). However, the fact that there are many methods to address the allocation problem has led to continued debate among LCA practitioners on the choice of allocation method (Curran, 2007; Weidema and Schmidt, 2010). We adhere to the common finding that there is no one best method and consequently, explore the implications of four allocation methods for the cogeneration case, henceforth referred to as M1, M2, M3 and M4. This approach is know as "allocation by physical causal or other relationship" to solve the allocation problem (Guinée, 2002; Ekvall, 2001). The fuel chargeable to electricity (FCE; in GJ/MW h representing the amount of fuel allocated to electricity) under each allocation method is calculated using Eqs. (6)–(9).

Method M1 (Eq. (6)) is based on the additional fuel consumed in the cogeneration case to produce electricity compared to the baseline option. Under this method, fuel that would have been consumed by the boiler in the baseline option—the most likely method to produce steam if a cogeneration system was not employed—to produce an amount of steam equivalent to the HRSG output (i.e. H_1) is allocated to steam. The difference between the total fuel consumed by the cogeneration system and the fuel allocated to steam is assigned to cogenerated electricity. This method is also known as "displacement allocation" in the LCA literature (Guinée, 2002; Allen et al., 2009).

Under the M2 method fuel is allocated in proportion to the amount of energy contained in the two useful products (steam and electricity) of the cogeneration system (Eq. (7)). This "energy allocation" method is simple and straightforward, but focuses only on the quantity of energy, ignoring the fact that electrical energy is higher in quality than steam.

The M3 method takes both the quantity and the quality of the two energy products by allocating fuel in proportion to exergy in each product (Eq. (8)). Exergy of the steam produced is calculated by multiplying the steam enthalpy by the exergetic temperature factor, τ (Rosen, 2008). Since exergy of steam depends on the steam temperature (T) and the reference environment temperature (T_0), FCE_{M3} is linked to the operating conditions.

The M4 method allocates fuel in proportion to the economic value of the products (Eq. (9)). In this analysis, the economic value of electricity (p_e) is set to be equal to the average price of electricity, which is assumed to be \$50/MW h. The economic value of steam (p_h) is assumed to be the average cost of 1 GJ of steam produced by the baseline boiler at natural gas price of \$5/GJ (in this case p_h=\$4.30/GJ). The CO_2 emissions intensity of cogenerated electricity (I_{cogen}) under a given allocation method is calculated by multiplying FCE by I_{cng} (Eq. (10))

$$FCE_{M1} = \frac{F_{cogen} - (H1 - H_{fw1})/\eta_B}{E_c} \tag{6}$$

$$FCE_{M2} = \left(\frac{E_c}{E_c + H_1}\right) \cdot F_{cogen} \cdot \frac{1}{E_c} \tag{7}$$

$$FCE_{M3} = \left(\frac{E_c}{E_c + \tau \cdot H_1}\right) \cdot F_{cogen} \cdot \frac{1}{E_c} \tag{8}$$

where $\tau = 1 - T_0/T$

$$FCE_{M4} = \left(\frac{p_e \cdot E_c}{p_e \cdot E_c + p_h \cdot H_1}\right) \cdot F_{cogen} \cdot \frac{1}{E_c} \tag{9}$$

$$I_{cogen} = FCE_{Mx} \cdot I_{cng} \tag{10}$$

where x=1,2,3,4

$$W_{offset} = (I_{offset} - I_{cogen}) \cdot E_c \cdot u \cdot 8760 \tag{11}$$

The CO_2 emissions offset is calculated using Eq. (11). Here we assume that cogenerated electricity displaces more carbon intensive electricity in the Alberta electric power system. The offset amount is determined by I_{cogen}, and the CO_2 emissions intensity of displaced electricity, I_{offset}. In a "deregulated" electricity market such as in Alberta, determining which electricity generators are being displaced by cogeneration units with a high degree of certainty is not possible, as generation dispatch information is kept confidential. Thus we provide reasonable estimates that can be made using publicly available data. We investigate the implications of four electricity displacement scenarios referred to as S1, S2, S3, and S4.

Scenario S1 assumes I_{offset} to be the average CO_2 emissions intensity of the Alberta electric system. Average CO_2 intensity of the Alberta electric system for the period 2000–2008 was calculated using the data published by the AESO (2009a) and the calculation details are presented in supplementary information.

Scenario S2 assumes that cogenerated electricity, when dispatched, displaces the units operating at the margin of the generator dispatch stack. In a competitive electricity market environment, the system operator dispatches different generators to meet the demand following a cost minimization that takes in bids from participating units. The bid price of the last unit dispatched becomes the system price of that particular hour, thus called the price setting unit. We assume that for every MW h of cogenerated electricity, another MW h is backed off from the unit operating at the margin. The CO_2 emissions intensity of the operating margin for the period from 2000 to 2008 is calculated using the price setting data published by the AESO (2009a).[5]

The third scenario, S3, assumes that cogenerated electricity displaces coal fired base load units. As the cogeneration units follow the thermal load of the host facility, they may very well operate as base load generators, bidding appropriately during peak load and off-peak load hours. Hence it is plausible that they may displace coal fired units. Scenario S4, following the SGER, assumes that cogenerated electricity displaces natural gas fired combined cycle gas turbine (CCGT) generators.

In order to determine the cost of CO_2 mitigation from cogeneration and also to investigate how the cogeneration system economics are affected by CO_2 management policies, an engineering economic analysis is developed. We include only the capital and operating costs to procure energy for bitumen extraction assuming that project development (drilling, land lease, etc.) and non-energy related operating costs are identical for both baseline option and cogeneration option. The main cost parameters assumed for the analysis are listed in Table 3. A pre-tax 12% real discounting rate was used for the engineering economic analysis. This discounting rate over a project life of 20 years corresponds to an annual capital charge factor of 13.3%.

4. Results and discussion

Using the mass and energy balance model we compute the fuel consumption and CO_2 emissions of the two options to satisfy the energy demands of the bitumen extraction project. Results of the

[5] In its "2008 Annual Report" the AESO reports the percentage of the time a certain fuel or generation technology (coal, natural gas, hydro, etc.) set the system price and we assume that the particular fuel or technology operated in the margin for the same amount of time. However, the data are aggregated and do not specify which unit is setting the price due to the proprietary nature of such information. This leads to uncertainties in the calculated emissions intensity as we used a single heat rate value for a given generation technology (see supplementary information for more details).

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engineering economic analysis and an examination of historic electricity and natural gas prices in Alberta were used to assess the economic competitiveness of the cogeneration option.

The onsite CO_2 emissions of the cogeneration option are 42% higher than the baseline option due to the additional fuel consumed to produce electricity. However, as shown in Fig. 2, when the CO_2 emissions from producing electricity in the Alberta electric system (an equivalent amount to the electricity generated in the cogeneration option at an assumed average CO_2 intensity of 0.84 tCO_2/MW h) are added to the baseline option to estimate the total emissions, the net CO_2 emissions of the cogeneration option are 31% lower. However, there is considerable uncertainty in determining which electricity generating units are being displaced by cogenerated electricity. Depending on the emissions intensity of the units assumed to be displaced, the total Provincial emissions of the cogeneration option are estimated to be from 6% to 38% lower than that of the baseline option. This is explored further in Section 4.2.

Table 3
Cost parameters used for engineering economic analysis (all costs are in 2008 Canadian dollars).

Cost parameter	Value
Capital cost	
Boiler	400 $/($GJ_h$/h)
Cogeneration	1400 $/$kW_e$
Fixed O&M cost	
Boiler	4 $/($GJ_h$/h)
Cogeneration	14 $/$kW_e$-year
Variable O & M cost	
Boiler	2 $/$GJ_h$
Cogeneration	2 $/MW h_e
Natural gas price	2–10 $/GJ
Electricity price	0–100 $/MW h

4.1. CO_2 emissions

The CO_2 emissions intensities of cogenerated electricity under different allocation methods are compared to those of other fossil fuel based electricity, Alberta's grid average, and marginal electricity production in Fig. 3. These results show that the carbon intensity of cogenerated electricity calculated using any of the four allocation methods considered is less than the fossil fuel based electricity generation technologies and the two Alberta grid emission intensities (with the exception of the cogenerated electricity under the M4 method compared to the intensity of CCGT).

The choice of allocation method is an important regulatory decision in controlling emissions from multi-product output facilities through facility based or product based regulations. As mentioned in Section 3, there are many alternative methods to allocate emissions among multiple outputs derived from a common stream of energy and resources and most of those methods can be rationalized using sound technical or logical arguments. The allocation method should be chosen considering the context in which allocation is carried out (Frischknecht, 2000). In case of emissions control, the regulatory choice of the allocation method should reflect the way the output products are valued in rational and profit seeking corporate investment decision making. Therefore, an argument can be made that the allocation method based on the economic value (M4) should be used where an allocation method is needed for emissions control regulations. The calculation procedure under M4 method should consider both the capital cost and operating cost allocations as well as the expected revenue form the products. This procedure is information intensive and depends on exogenous parameters. For example in our cogeneration example system, the FCE under M4 method varies with natural gas and electricity prices. The M1 method depends on the operating efficiencies of the cogeneration system and also represents the marginal fuel cost of cogenerated electricity. Hence it can be considered as a close approximate to economic and technical decision making. Of the four allocation methods investigated, only the M2 method is deemed inferior due to its flaws

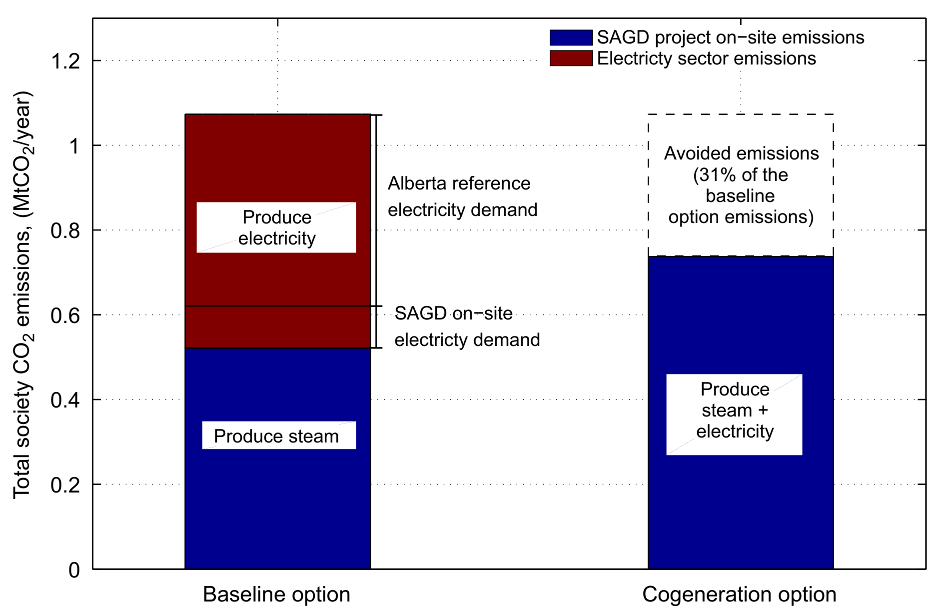

Fig. 2. The total CO_2 emissions in Alberta, to deliver 124,400 TJ (H) of steam and 650 GW h (E_c) of electricity annually under the two energy options, are presented in this figure. The two columns depict the CO_2 emissions associated with an identical amount of steam and electricity. Therefore CO_2 emissions from generating an equivalent amount of electricity as in the case of cogeneration option (including both electricity consumed onsite and exported to the grid) in the Alberta electricity system (which has an average CO_2 intensity of 0.84 tCO2/MW h) is added to the baseline option. No electricity sector emissions are added to the cogeneration option assuming that cogenerated electricity displaces equivalent amount of high carbon intensive electricity in the Alberta grid. As indicated in the figure, the total Alberta emissions of the cogeneration option are 31% lower than that of the baseline option.

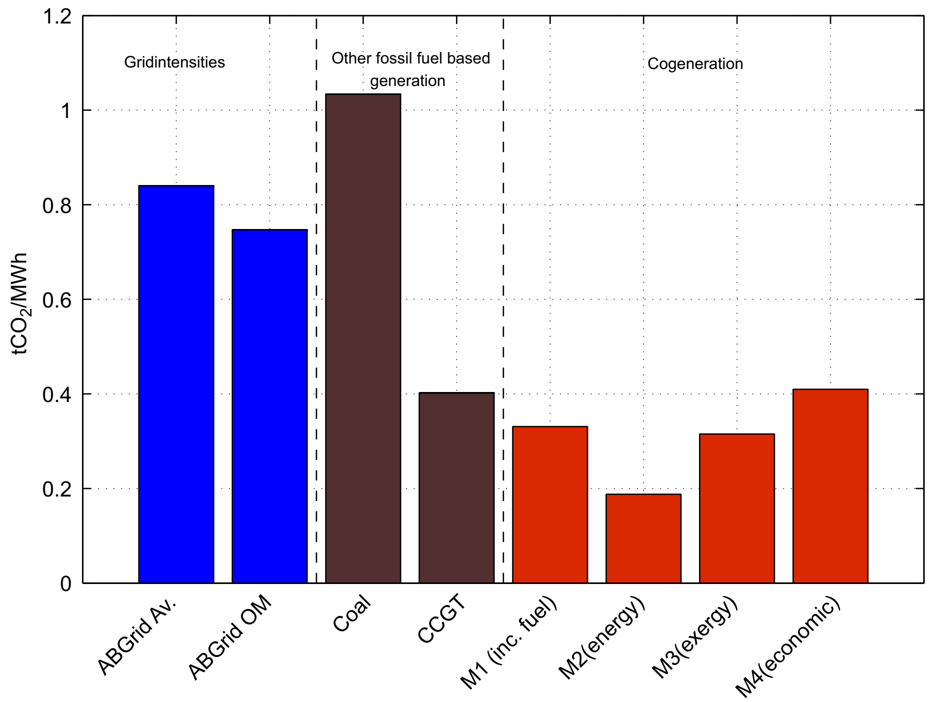

Fig. 3. This figure depicts the CO_2 emissions intensities of the Alberta electric system (average and marginal intensities), coal fired generation, natural gas fired combined cycle generation, and cogeneration under different allocation methods (M1–M4). The grid average intensity calculation considers the energy traded in the Alberta electricity market and excludes the onsite generation that serves behind-the-fence loads (but include the electricity exported to the Alberta grid by behind-the-fence generators such as cogeneration units).

discussed in Section 3.[6] In the remainder of the analysis, where we have to use a single allocation method to retain simplicity, we use the M1 allocation method to calculate FCE.

Fig. 4 depicts a forecast of the CO_2 emissions from electricity generation in Alberta under two scenarios and the corresponding emissions intensities. We focus on the time period up to 2020, which coincides with the Provincial target of 50 MtCO2e of emissions reductions. This forecast considers the present generation fleet, planned generation unit additions and retirements, and the new installed capacity expected to meet the forecasted electricity demand to the year 2020.[7] The generation scenario GS1 assumes new additions that are yet unplanned will be coal fired generators. Scenario GS2 considers an alternative case where these new additions will be cogeneration systems, employed in the oil sands sector. We assume that carbon capture and storage will not be implemented within the time period of this forecast. Both scenarios are plausible given the corporate announcements made by utility companies to build new coal fired power plants and the forecasted growth of oil sands sector combined with the potential to use cogeneration systems to satisfy their energy demands (see supplementary information for details of the forecast). The scenario GS1 is assumed as the business as usual (BAU) scenario due to the existing large reserves of coal in Alberta, the potential to develop brownfield coal fired generation to replace retiring units as well as the ability to expand the generation capacity of existing coal fired generators. The transmission system expansions announced by the AESO can facilitate either of these generation scenarios (AESO, 2009b).

As shown in Fig. 4, a 11–17% reduction of Alberta electricity sector CO_2 emissions below the BAU scenario could be achieved by integrating more cogeneration. However, the use of GS1 as the BAU scenario is subject to challenge. A strict carbon emissions control regulation enacted by the province or the Canadian federal government could constrain the growth of both the oil sands sector and coal fired electricity generation. However, there is significant uncertainty in the timing and stringency of such regulation. We test a third scenario (GS3) by assuming that the new generation additions to replace the retiring units and to serve the forecasted demand growth will be natural gas fired CCGT units (see supplementary information for details). Total CO_2 emissions under the high cogeneration scenario, GS2, is only 2–5% lower than the high CCGT scenario, GS3, demonstrating that the choice of BAU will have an impact on the estimates of the emissions reduction potential of cogeneration. It also suggests that a similar level of emissions reductions is possible through increased deployment of natural gas fired CCGT generators.

There is significant risk in picking a technology winner as opposed to setting a target standard that can be met using a mix or blend of technologies, each keyed to the sub-region or resource base being accessed. Therefore, we estimate the cost of mitigating CO_2 in the Alberta electricity sector using alternative electricity generation technologies compared to a supercritical pulverized coal (SCPC) power plant as shown in Table 4. SCPC was used as the new coal fired electricity generation technology, as it is assumed to be the dominant technology of new coal fired units that will be built before 2020. This is consistent with the new SCPC units that are being built and are planned in Alberta (AESO, 2010). However, the baseline chosen for comparison will greatly affect these results and therefore, care should be taken in selecting and interpreting the baseline for this type of analysis. The estimated carbon mitigation cost of cogeneration compared to SCPC is -14 \$/tCO_2 (a negative abatement cost means that under the assumed conditions, both the average cost and the

[6] This is not a general conclusion. There can be allocation situations where "energy allocation" is suitable. However, in the case of cogeneration, this method is not suitable because the significantly different qualities of the two energy products are not taken into account.

[7] Planned additions are the units that are under active construction and the ones that have received regulatory approval.

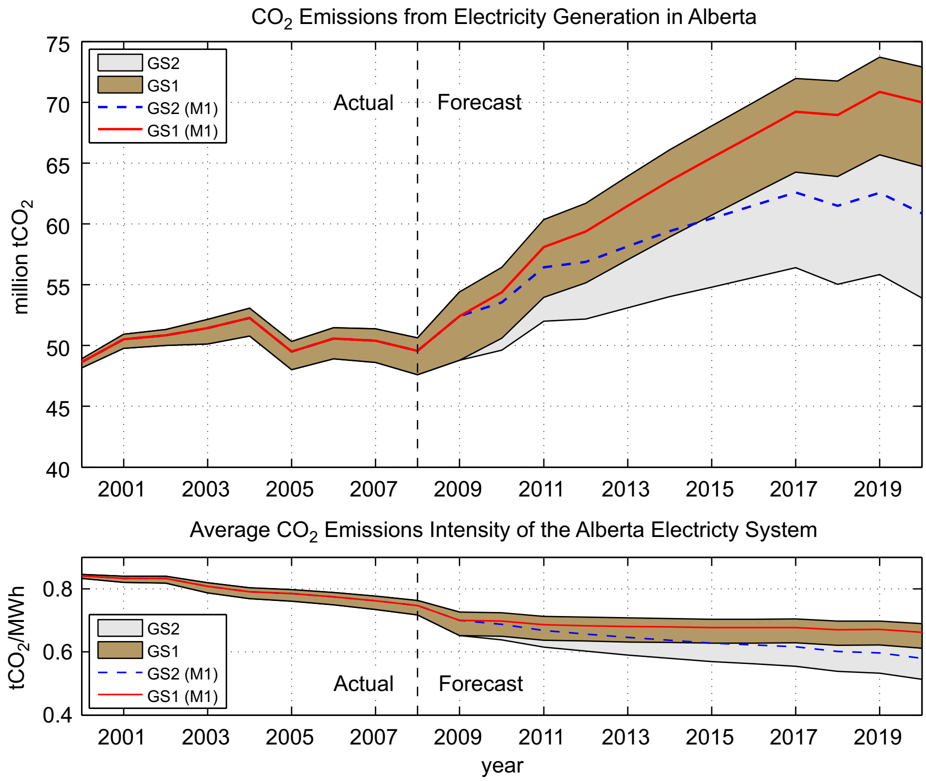

Fig. 4. A forecast of CO_2 emissions from the Alberta electric system to 2020 is presented in this figure. The generation scenario GS1 is a high coal option and GS2 is a high cogeneration option (details of the two generation scenarios are summarized in Section 4 and full details are presented in the supplementary information). The range of emissions under each scenario is due to the different allocation methods used to calculate the emissions intensity of cogenerated electricity. Therefore the range widens with the increasing amount of cogenerated electricity in the mix. If the allocation method M1 (incremental fuel based) is used to divide the fuel between steam and electricity produced by a cogeneration system, the outlook of the total CO_2 emissions (and the average CO_2 intensity) attributable to the electricity generation in Alberta under the scenario GS1 and GS2 are depicted by the lines GS1(M1) and GS2(M1) respectively. Depending on the allocation method, the electricity sector emissions outlook under the scenario GS2 (high cogeneration) is 11–17% lower than that of GS1 (high coal or BAU).

carbon intensity of cogenerated electricity are lower than SCPC), the lowest among the generation technologies considered. This carbon abatement cost is lower than estimates for carbon capture and storage from new coal power plants, which are in the range of \$70–100/tCO_2 (ICON, 2009). Given these results, cogeneration presents an effective option to reduce the CO_2 emissions of the Alberta electricity sector.

Our analysis shows that, in general, the cogeneration option is economically favorable compared to the baseline option. However, the economics of cogeneration are tightly correlated with natural gas and electricity prices. With a natural gas price of \$5/GJ and an electricity price of \$60/MW h, the total cost of energy input per barrel of bitumen produced under the baseline option is \$6.6 and that of the cogeneration option is \$5.5. The market price of electricity varies hour to hour throughout the day because different generation units are dispatched to meet the time varying electricity demand at the minimum cost. On average we expect the hourly electricity price to be equal to the marginal cost of generation, which in turn depends primarily on the fuel cost for thermal electricity generation.

We examine the competitiveness of cogenerated electricity under historic electricity and natural gas prices in Alberta in order to determine the potential value and role of cogeneration in the future. As discussed above we use the M1 allocation method to calculate the marginal fuel consumption for cogenerated electricity. Under the M1 method, the implied heat rate of the cogeneration system in our illustrative example system is 6.7 GJ/MW h. The average annual natural gas price in the years 2007 through 2009 in Alberta was \$6.24/GJ, \$7.81/GJ, and \$3.93/GJ respectively. The hourly electricity prices of the Alberta power market in those years were less than the average fuel cost of cogenerated electricity 44%, 40% and 32% of the time respectively. We can also use the market heat rate[8] to examine the competitiveness of a generation technology under both electricity and natural gas price fluctuations. In general, a generator with a heat rate above the prevailing market heat rate is operating at a loss. The heat rate of the cogeneration system we model (6.7 GJ/MW h; M1 allocation method) is higher than the hourly market heat rate in Alberta in the years 2007 through 2009 47%, 46% and 28% of the time respectively. Conventional thermal generating units such as CCGT can adjust their output in response to these market fluctuations (e.g., reduce output when market price is low and vice versa). However, cogeneration units typically follow the host facility's thermal load and cannot reduce or shut down electricity production following the electricity price. Under these conditions, the economics from the power sold by in situ extraction projects is not always favorable so they may choose to size power generation capacity to meet their own needs rather than sell to the grid.

4.2. Policy implications

In order to determine whether the current Alberta policy is sufficient to incent investments in cogeneration, we calculate the emissions reduction obligations of the two options under SGER according to the guidelines set by Alberta Environment (AENV, 2009). Results of SGER obligations calculations are shown in Fig. 5 (see supplementary information for SGER obligations calculations

[8] Market heat rate = market price of electricity/natural gas price; expressed in GJ/MW h.

Please cite this article as: Doluweera, G.H., et al., Evaluating the role of cogeneration for carbon management in Alberta. Energy Policy (2011), doi:10.1016/j.enpol.2011.09.051

Table 4
Estimates of carbon mitigation costs of alternative electricity generation technologies compared to a super-critical pulverized coal power plant (*Baseline* unit). In each case the transmission costs are equally distributed across the grid and assumed to be built in proportionately to the power supplied. The Province has undertaken a series of transmission upgrade projects sufficient to provide adequate future capacity to meet projected loads including oil sands expansion. Funding for right of way and capital costs will be apportioned initially outside the rate base and charged back to reflect load served in operations.

Parameter/Estimated value	SCPC	CCGT	Cogen	Wind power
Fuel	Coal	NG	NG	Wind
Capital cost ($/kW)[a]	3000	1365	1000	2200
Fixed O&M cost ($/kW-year)	31	13	13	56
Variable O&M cost ($/MW h)	6	4	4	0
Fuel price ($/GJ)	1.5	6	6	0
Fuel carbon intensity (tCO_2/GJ)	0.1	0.05	0.05	0
Heat rate (GJ/MW h)[b]	9.4	7.7	6.7	0
Cost of electricity ($/MW h)	71	87	63	114[c]
Carbon intensity (tCO_2/MW h)	0.94	0.39	0.34	0
Cost of CO_2 reduction ($/$tCO_2$)	**Baseline**	**29**	**−14**	**46**

SCPC—super-critical pulverized coal; all costs are in 2008 Canadian dollars (average conversion rate in 2008 CAD 1=USD 0.94).

[a] The source of capital costs of all generation technologies except cogeneration is AESO (2009b). Capital cost of SCPC is based on a unit size of 450 MW and that of CCGT is based on a unit size of 300 MW. Cogeneration capital cost attributable to electricity generation is assumed to be the difference between the capital cost of a cogeneration system (gas turbine+HRSG) and that of an industrial boiler with identical steam generation capacity.

[b] All heating values are based on higher heating values. Heat rate of the cogeneration unit is based on the allocation method M1.

[c] Cost of wind energy does not includes the cost of new transmission developments required to integrate wind and the cost associated with mitigating the intermittency of wind.

details). The baseline option has an annual emissions reduction obligation of 63,000 tCO_2 and the cogeneration option earns 15,000 tCO_2 of EPCs. As discussed in Section 2.3, the present Alberta GHG emissions reduction policy implicitly caps the price of carbon at $15/$tCO_2$. Therefore, the SGER compliance cost of the baseline option is $0.1/bbl of bitumen. For perspective, if this was factored into energy of this option, the energy cost would increase by 1.5%. In the case of the cogeneration option the EPCs earned under SGER translates to a savings of $0.02/bbl of bitumen, reducing the energy cost only by 0.4%. If the value of EPCs earned under SGER is attributed to electricity, the marginal cost of cogenerated electricity will reduce by $0.34/MW h. As mentioned above, without SGER benefits, the marginal cost[9] of cogenerated electricity was higher than the electricity prices in Alberta in 2008 and 2009 40% and 32% of the time respectively. Lowered marginal cost due to the SGER performance credits of $0.34/MW h reduces the fraction of time where the marginal cost is higher than the electricity price less than 1% point in both years (we consider only 2008 and 2009 because the SGER compliance period started in 2008). Hence, the current Alberta GHG emissions reduction regulation in its present form is not sufficient to considerably increase the competitiveness of cogeneration and influence cogeneration investment decision making.

Another limitation of SGER is the use of CO_2 emissions intensity of a CCGT unit to calculate the "deemed emissions attributed to electricity" as described in Section 2.3. In this case the SGER guidelines assume that in the absence of cogeneration systems, the electricity demand of the host facility will be met by CCGT units. Given the present generation mix in Alberta and new generation additions that either have regulatory approval or are under active construction, this is not a realistic assumption (AESO, 2010). Under the present regulatory environment, coal is still likely to be the dominant generation technology, which will result in a high average electricity emissions intensity. Instead of using the CO_2 intensity of CCGT (to calculate the "deemed emissions attributed to electricity"), one of the allocation methods could be used. However, this would create a worse off situation for cogeneration, either by increasing the emissions reduction obligations (allocation methods M1–M3) or by reducing the amount of EPCs that may be earned compared to EPCs earned under current SGER rules (see Fig. 5).

When there is a significant amount of cogeneration in the electricity generation mix, the emissions intensity of cogenerated electricity, I_{cogen}, is required to calculate both the average and the marginal CO_2 emissions intensity.[10] However, as described in Section 3, I_{cogen} depends on the allocation method (i.e., how the emissions are divided between electricity and heat/steam; see Fig. 3) and therefore, the method employed affects the average and marginal CO_2 emissions intensity. For example, as shown in Fig. 4 the exact value of the total CO_2 emissions and the average emissions intensity of the Alberta electric sector depend on the allocation method used to calculate I_{cogen}. It can also be seen that the range widens with the increasing share of cogenerated electricity (in 2009 the variability in total CO_2 emissions depending on the allocation method employed was 5.6 MtCO2). Therefore, a carbon management policy that uses the average or marginal emissions intensities of the electric system must also set the allocation method that should be used to calculate the emissions intensity of cogeneration units. Furthermore, different cogeneration system configurations (steam turbine based, gas turbine based, etc.) that are/could be employed complicate the estimation of emissions intensities by using aggregated data. For simplicity, when preparing the emissions forecast depicted in Fig. 4, we apply the I_{cogen} values (see Fig. 3) from our model to all the cogeneration units in the Alberta generation mix. Through sensitivity analysis we are confident that the values we use are of the same order of the magnitude of the emissions intensities of the respective cogeneration units under the allocation methods M1–M4. A comprehensive survey of cogeneration units employed in the generation mix is required to make a more accurate estimate of associated emissions intensities.

4.3. Policy options

We explore alternate policy options and their ability to increase the competitiveness of cogeneration. First, we consider a case where the carbon management policy allows the cogeneration systems to earn carbon emissions offset credits for grid electricity displacements. Annual offset credits that our modeled system may earn under different allocation methods (M1–M4) and different electricity offset scenarios (S1–S4) are shown in Fig. 6. These credits are calculated using Eq. (11) as described in Section 3. A comparison of Figs. 5 and 6 shows that all the offset scenarios except S4 with the allocation method M4 provides higher credits for the cogeneration system than SGER EPCs. These offset credits may be used to meet the facility's own emissions reduction obligations or be sold to other parties who have emissions reduction obligations. An Alberta based offset credits market already exists to sell credits for parties who have SGER emissions reduction obligations.

It is also possible to provide more credits to the facilities with cogeneration within the SGER framework by changing the

[9] Marginal cost is assumed to be equal to the sum of fuel cost and variable O&M costs.

[10] In Alberta currently about 30% of the electricity is generated by cogeneration units while they operate in the margin (i.e., set the price) 25% of the time on average (AESO, 2009a; MSA, 2009).

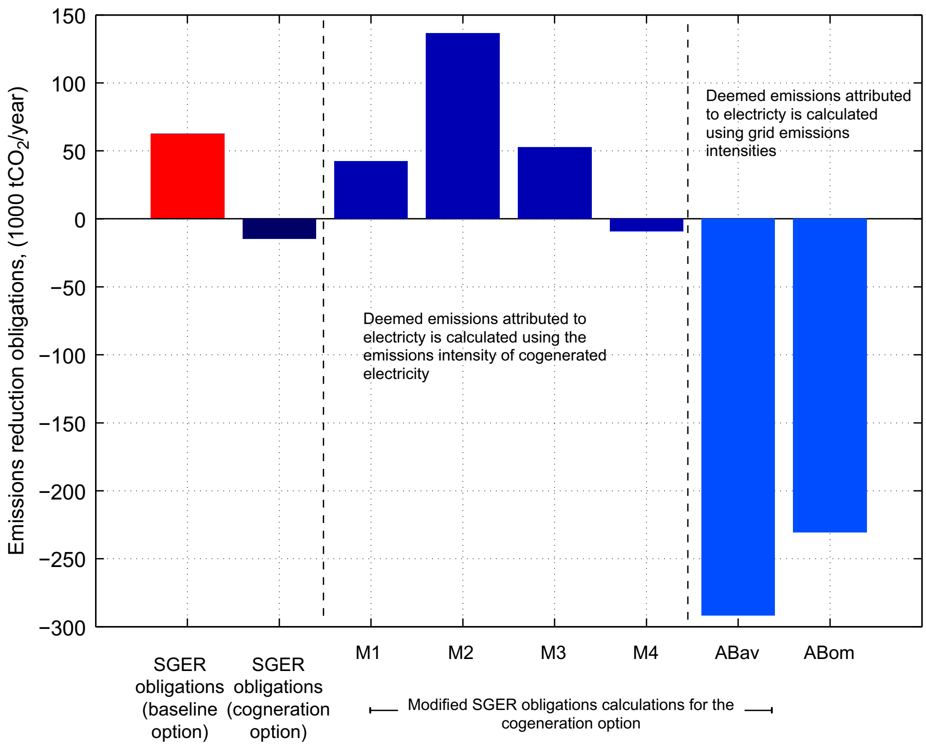

Fig. 5. The first two columns of this chart depict the emissions reduction obligations of the baseline option and the cogeneration option under the current SGER rules. Next four columns depict the emissions reduction obligations calculated with modified SGER guidelines where the emissions intensity of cogenerated electricity under different allocation methods (M1–M4) is used to calculate the deemed emissions from electricity instead of the CCGT emissions intensity. This modification to the present SGER rules creates an unfavorable situation for the cogeneration option either by obligating to reduce emissions or by reducing EPCs. However, under all allocation methods, except M2 method (energy based), the cogeneration option is still the preferred option in terms of emissions reduction obligations. The last two columns depict the amount of EPCs the cogeneration option under SGER if Alberta grid intensities (average and marginal intensities) are used to calculate the deemed emissions attributed to electricity. As can be seen from the figure, such modifications to SGER rules create a favorable environment for cogeneration option.

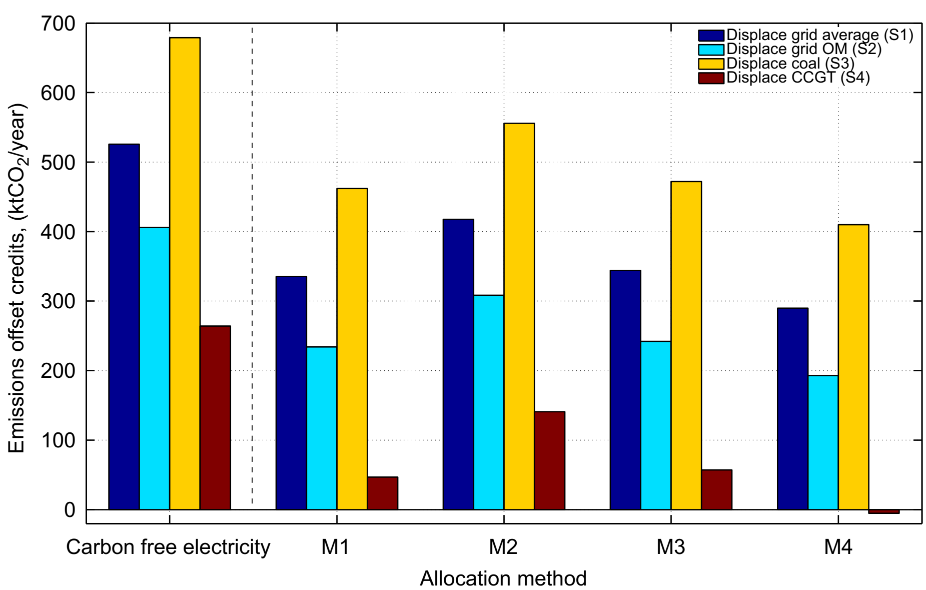

Fig. 6. CO_2 emissions offset credits that may be earned by the cogeneration option are depicted in this figure. The amount of credits depends on two factors: the allocation method used to calculate the emissions intensity of cogenerated electricity and the emissions intensity of displaced electricity. This figure shows the offset credits under the four allocation methods we considered (M1–M4) and four displacement scenarios (S1–S4). The group "carbon free electricity" shows the offset credits earned by a carbon free electricity generation unit (such as wind power, photovoltaics, biomass, etc.) under the four displacement scenarios and is shown for comparison. This may also viewed as the offset credits earned by the cogeneration system if all the emissions are allocated to steam and electricity is considered to be emissions free.

method used to calculate the deemed emissions attributed to electricity. Instead of using the emissions intensity of CCGT, as is the case of the current procedure, the average emissions intensity of the Alberta electricity sector may be used. This would represent the case where cogenerated electricity displaces the average generation mix, which is dominated by coal fired generation. Use of the current average emissions intensity of 0.84 tCO_2/MW h as the basis of calculating the deemed emissions attributed to electricity would increase the EPCs earned by the cogeneration option to 292,000 tCO_2 from 15,000 tCO_2 under the current guidelines (see Fig. 5). Attributing all the EPCs earned under this modified SGER obligation calculation to electricity at $15/$tCO_2$ reduces the marginal cost of cogenerated electricity by $6.7/MW h. Similarly, if a cogeneration system operator participates in the electricity market by following load (instead of following their own thermal demands) the marginal emissions intensity of the Alberta electricity sector could be used to calculate the deemed emissions attributed to electricity. These conditions result in a significant benefit for facilities with cogeneration.

As discussed above when controlling carbon emissions from multi-product facilities such as cogeneration through regulations based on offset credits for lower carbon intensive technologies, or facility based intensity reduction targets such as the SGER, the regulator is faced with the challenge of selecting the appropriate method to allocate a facility's emissions among multiple outputs. Furthermore, in the case of offset credits based systems, particularly electricity offsets, there is significant uncertainty in determining what is being displaced by the low carbon alternative. This fact merit further analysis. For example, if the assumption is that cogenerated electricity displaces a single type of generation technology such as coal or CCGT (Figs. 3 and 6; scenarios S3–S4), the CO_2 intensity of a representative unit of that technology should be determined at the time of policy adoption. That decision should be made considering the existing generating units as well as future generation unit additions. Of the four offset scenarios considered in this analysis, the required information to calculate the grid average emissions (scenario S1) intensity may be already available from various emissions reporting sources. For example, Alberta's "Specified Gas Reporting Regulation" requires the major CO_2 emitters such as electric power producers to report their emissions annually (AENV, 2011). Nevertheless, uncertainty remains as to the accuracy of the assumption the displaced electricity emissions intensity is equal to the average grid intensity. The marginal emissions intensity (scenario S2) is the scenario that is most difficult to calculate with reasonable certainty. In order to calculate the marginal intensity the regulator must know which generating unit was operating at the margin over a given time frame as well as its emissions intensity. In a deregulated market environment such information is privileged and only the independent electric system operator (in Alberta the AESO) has the full knowledge of the marginal unit. Various aggregated data sources are available (for example, AESO, 2009a; MSA, 2009), although the accuracy of the marginal emissions intensity derived from them is debatable.

Figs. 5 and 6 depict the uncertainties in the incentives or obligations for the cogeneration system in our model due to different allocation methods and electricity displacement scenarios. If the regulator chooses to implement carbon pricing by using facility or product based regulations, the emissions accounting methods must be chosen in such a way that they match the intended policy objectives. For example, consider the results presented in Fig. 5. If the objective of the policy is to provide a significant amount of credits for cogeneration to promote investment, the SGER rules may be modified, such that the deemed emissions attributed to electricity is calculated using grid average intensity. Conversely, if the policy maker wishes to promote low carbon emissions intensive operations without giving as many credits as the current SGER rules, the deemed emissions attributed to electricity may be calculated using the emissions intensity of cogenerated electricity under M1 allocation method. In this case no net credits are granted to a bitumen extraction project with cogeneration, yet its emissions reduction obligations are lower than that of a project without cogeneration.

5. Conclusions

Oil sands operations will likely provide a significant share of crude oil deliveries within North America for the next few decades, with corresponding demand for natural gas and delivered electricity to support their operations. Use of cogeneration to satisfy the energy demands of oil sands operations may be an effective strategy for reducing CO_2 emissions of the electricity sector of Alberta. However, this conclusion is likely to be true and most effective in the short run (before 2020) when installed coal generation with limited emissions controls continues to supply a significant fraction of electricity in the province. Beyond this point, it is likely that displacement of electricity generated from natural gas (and other lower emissions intensity sources) may offset or diminish the value of cogeneration for carbon management in Alberta. In the face of this trend, with falling electric sector emissions, long term oil-sand cogeneration benefits may be most effective and sustaining if installed immediately.

Cogeneration can offset a significant and locationally important segment of Alberta's base load electricity demand currently satisfied by coal fired generators. The regulatory system can facilitate the integration of cogeneration systems within oil sands operations through a combination of permits, tax incentives and regulatory credits. The result in the short term will be measurable benefits from emissions reductions associated with the electricity sector. However, since the present carbon management policy of Alberta does not impose a significant marginal carbon price signal there is limited influence on oil sands project operator's decisions to invest in cogeneration. With a strong carbon price signal, cogenerated electricity will be a more competitive base load generation option.

A more efficient solution is available, simply by focusing on a carbon tax. Here, the fuel used can be taxed based on its carbon intensity, resulting in an economy wide, consistent carbon price. Use of lower carbon intensive fuel such as natural gas combined with the inherently high efficiency will make cogeneration competitive compared to other electricity generation technologies (see Table 4). Furthermore, enforcing a price on carbon at the source eliminates the need for down stream carbon accounting that demands significant data collection and complex accounting methods.

When facing a lack of political will for a carbon tax, alternative methods should be chosen to mimic the effect of such a tax. This merits further research. For example with respect to cogeneration, future work could provide guidance on the accounting methods such as co-product allocation that provide the same level of incentives as a carbon tax.

We may draw more general lessons from this analysis. Regulations that attempt to manage emissions on a product and facility basis may become arbitrary and complex as regulators attempt to approximate the effect of an economy-wide carbon price. If one counts only the direct emissions from facilities, then the system is simple, but encourages counterproductive activity as industry might try to move emissions outside their "fence". Though less supported in the current political climate, economy-wide policies would address off-site emissions in a more direct manner. Regulators can attempt to improve the regulations by accounting for indirect emissions on a product basis, in this case emissions from purchased electricity, to avoid such perverse outcomes. But as one adds more complexity the system becomes more arbitrary, and more subject to gaming by industry.

Improvements to the transparency of carbon management policies include clearly stating the methods for accounting procedures and assumptions made. In addition, all the data associated with calculating emissions of a product or a facility should be made easily accessible in the public domain. As demonstrated in this analysis, a number of rational emissions accounting methods are available and they provide different levels of incentives for cogeneration. Therefore, policy makers should select the appropriate accounting methods that reflect the intended policy goals.

Appendix A. Supplementary data

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.enpol.2011.09.051.

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