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CO_2 capture and storage from a bioethanol plant: Carbon and energy footprint and economic assessment

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ABSTRACT

Biomass energy and carbon capture and storage (BECCS) can lead to a net removal of atmospheric CO_2. This paper investigates environmental and economic performances of CCS retrofit applied to two mid-sized refineries producing ethanol from sugar beets. Located in the Region Centre France, each refinery has two major CO_2 sources: fermentation and cogeneration units. "carbon and energy footprint" (CEF) and "discounted cash flow" (DCF) analyses show that such a project could be a good opportunity for CCS early deployment. CCS retrofit on fermentation only with natural gas fired cogeneration improves CEF of ethanol production and consumption by 60% without increasing much the non renewable energy consumption. CCS retrofit on fermentation and natural gas fired cogeneration is even more appealing by decreasing of 115% CO_2 emissions, while increasing non renewable energy consumption by 40%. DCF shows that significant project rates of return can be achieved for such small sources if both a stringent carbon policy and direct subsidies corresponding to 25% of necessary investment are assumed. We also underlined that transport and storage cost dilution can be realistically achieved by clustering emissions from various plants located in the same area. On a single plant basis, increasing ethanol production can also produce strong economies of scale.

1. Introduction

It is now largely accepted by the scientific community that most of the global warming observed over the last 100 years is due to an increase in Greenhouse Gases (GHG) concentration in the atmosphere. In order to respond sufficiently to climate change, CO_2 emissions must decrease by 50–85% before 2050 (IPCC, 2005). To achieve this goal, several available strategies have been identified by Pacala and Socolow (2004), including: demand reduction, efficiency improvements, the use of renewable, nuclear power, and carbon capture and storage (CCS). The latter consists of capturing CO_2 from large stationary sources such as power plants, cement manufactures, refineries, and steel mills, and storing it in the subsurface where it can no longer contribute to global warming (IEA, 2007; IPCC, 2005).

In this study, we focus on a particularly attractive variant of the CCS technology portfolio, where part of stored CO_2 comes from biomass (BECCS: bio-energy with carbon capture and storage) instead of fossil fuel. Considering that carbon from biomass is neutral (because it is included in the natural carbon cycle), BECCS leads to a net removal of atmospheric CO_2, given sustainable biomass harvesting practice and the permanent geological storage of CO_2. According to Obersteiner et al. (2001), this option offers a double benefit of providing low-carbon energy products and removing carbon from the natural carbon cycle. Azar et al. (2010), IEA (2010b) showed that BECCS has also the potential to reduce the mitigation cost of reaching low atmospheric CO_2 concentration level targets. Moreover, according to Read and Lermit (2005) BECCS could even provide the potential for a return to pre-industrial CO_2 levels. Those last results are however somewhat controversial because they do not sufficiently take into account land scarcity as it relates to global biomass production capacities (Jepma, 2008; Rhodes and Keith, 2008).

Several sectors have been identified as apt targets for the biomass mitigation option, such as the heat and pulp mill industries (Hektor and Berntsson, 2007; Möllersten et al., 2006), the electricity sector (Carpentieri et al., 2005; Rhodes, 2007; Uddin and Barreto, 2007) and the biofuel sector (Möllersten et al., 2003; Kheshgi and Prince, 2005; Mathews, 2008; Lindfeldt and Westermark, 2008, 2009). Study results indicate that the relevance of environmental

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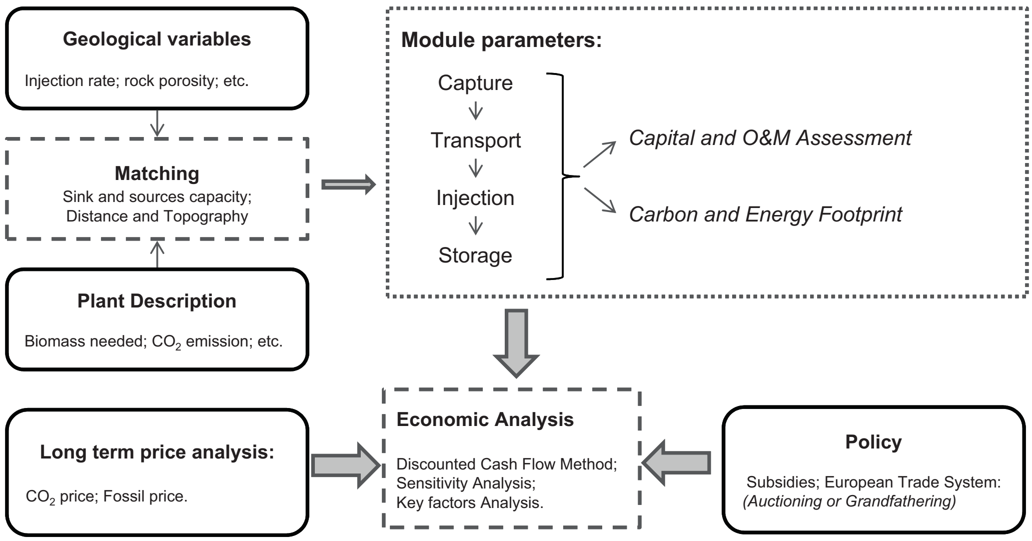

Fig. 1. BECCS chain analysis.

benefits for a BECCS project strongly depends on each individual case. In addition, when analysis methodologies followed are different, results are hardly comparable.

Lastly, a major issue regarding the deployment of BCCS is the economic viability of projects. Biomass sources are usually small scale facilities which have received modest attention in comparison with large fossil fuelled-facilities fitted with CCS technology (Ruben et al., 2007; Jakobsen et al., 2008; Wang and Nakata, 2009). However, the sugarcane ethanol sector has been identified as a niche market for an early implementation of CCS (Möllersten et al., 2003). The CO_2 stream released during the fermentation step is highly concentrated with few impurities compared to fossil fuel sources that generally have lower CO_2 concentrations (IPCC, 2005). As a consequence, only dehydration and compression are needed which significantly lower the cost of the CCS chain.

This study is a part of the CPER Artenay Project in France, which aims at quantifying both environmental benefits and economic feasibility of capturing CO_2 emissions from a medium sized bioethanol plant, and then storing them in a deep saline aquifer within the Paris Basin. An overall description of this project is given in Bonijoly et al. (2009). The ethanol is produced from sugar beets, which is one of the two major bioethanol feedstocks inside the European Union. This article shows the impact of CCS retrofit technology on two existing small sugar beet bioethanol production units. This is done with a "carbon and energy footprint" (CEF) analysis and a "discounted cash flow" (DCF) analysis in order to look at both environmental and economic performances. Moreover, the CCS chain has been designed considering the local surface and subsurface specificities (Fig. 1).

This paper is organized as follows: Section 2 gives a description of the case study (matching between sources and sinks, technical assumptions and scenarios); Section 3 describes the methodology used for both carbon and energy footprint and economic assessments; Section 4 presents the results, which are then discussed in Section 5. Finally, some preliminary conclusions regarding the application of this technology on small to medium sources are drawn in Section 6.

2. Description of the case study

2.1. Location

The study area is located within a 900 km^2 perimeter in south Paris Basin, near Orléans city, in a region that concurrent studies indicate as being favourable to CO_2 geologic storage. Two sugar beet refineries (named Artenay and Toury), producing more than 100,000 m^3 of bio-ethanol per year (around 200,000 tons of CO_2 when including all processes), are located above two well known Paris Basin deep saline formations (Dogger and Keuper aquifers). They could be used for CO_2 storage in this area provided that further local confirmation programs prove their suitability. Saline formations within Keuper sandstones and Dogger carbonates are very different from both structural and lithological points of view. Their characterization is reported in the study of Chapuis et al. (2008). In the present study, we consider storage within Keuper sandstones, which are deeper than Dogger carbonates, at roughly 2250 m below ground level. This choice was made according to a preliminary hydro-geological characterization, which reveals that this aquifer has a higher injectivity within the study area (Martin, 2009). Injectivity is defined as the capacity of a geological formation to receive a given volume of CO_2 during a given time with a good injectivity indicating that large volumes can be injected without generating a significant overpressure in the saline aquifer.

2.2. Technical plant description

The Artenay and Toury refineries process sugar beets to produce sugar and high purity alcohol for the perfume and solvent industries. The proportion of end products varies between those two refineries, even if the quantities of processed sugar beet are equivalent. For the sake of simplicity, and in spite of slightly different processes, we assumed in this study that the plants are identical and produce bioethanol only (carbon emissions linked to bioethanol production only are then considered). The proportion of sugar or bioethanol produced varies each year according to various parameters such as European sugar production permits and demand. However, in average bioethanol production requires 2/3 of the overall energy needs of the refinery. The process of a sugar refinery is described in Fig. 2. Two CO_2 sources are depicted: the natural gas fired cogeneration unit and the fermentation unit. For an ethanol production of 600,000 hl per year, CO_2 emissions are 45,000 tons from the fermentation unit and around 60,500 tons from the cogeneration unit. Although these annual volumes are relatively small, it is important to emphasize that the CO_2 flow rate is not constant during the year. Indeed, during the harvest period, which lasts three months (October–November), the bioethanol production is about 4800 hl/day, leading to a maximum total (fermentation + cogeneration) CO_2 flow rate around

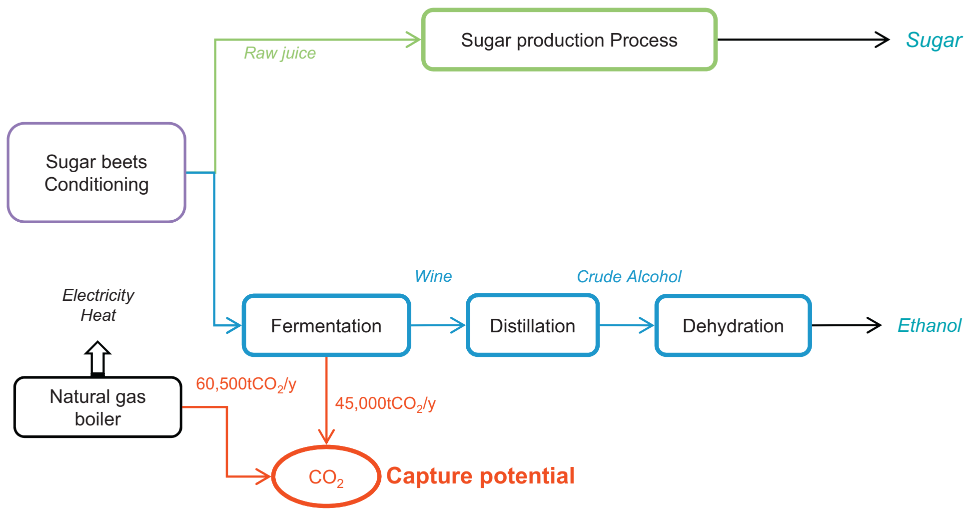

Fig. 2. Description of the sugar refinery process.

50 t/h, while during the rest of the year, the production decreases to 1600 hl/day, leading to a maximum total CO_2 flow rate around 17 t/h.

The current exhaust stream from the fermentation is mainly composed of CO_2 (about 85%), as well as O_2 and N_2. However, in this study, we assumed that it is composed of 100% of CO_2 which is not unrealistic since 95% CO_2 purity can be achieved without major changes to the existing process. Such a high content corresponds to an ideal anaerobic fermentation, where each processed mole of glucose yields one mole of ethanol and one mole of CO_2. Thus, as CO_2 from the fermentation process is considered to be pure, only a compression unit is necessary to condition CO_2 prior to transport: no capture process is required.

Although the specific composition of the stream coming from the cogeneration unit was not known, it was reasonable to follow generic assumptions: the CO_2 is diluted, making up around 8% of the mostly nitrogen exhaust stream volume. Therefore, a CO_2 separation process is required for CO_2 emitted by the cogeneration unit.

2.3. Design of the CCS units

The conditioning, transport, and injection units were designed and analysed using commercial process modelling software: Hysys® v.2004.2 (Aspen Technology, Inc., Cambridge, USA). The design takes into account the maximum CO_2 flow rate in order to capture all produced CO_2. However, the energy consumption takes into account the CO_2 flow rate variability along the year.

2.3.1. Capture and compression

Because the exhaust stream from the fermentation step is assumed to be pure CO_2, only the cogeneration unit requires a capture process. In this case, an amine-based post-combustion capture process with an assumed capture rate of 90% has been supposed. In order to condition CO_2 to dense phase for transport and storage, it requires the installation of a four-stage compression unit followed by one pump before the pipeline inlet. The gas is pressurized to over 80 bar, which is actually slightly higher than the critical pressure, and then pumped to reach 150 bar at the pipeline inlet. Conditioning CO_2 at this pressure is common practice for CO_2 pipeline transport and injection. Using Hysys® (v.2004.2), the resulting energy requirements for capture and compression were assessed and the analysis revealed that the energy needed for capture represents 85% of the total energy required by this stage.

2.3.2. Pipeline transport

Because of the short distance (roughly 30 km) and the absence of elevation differentials between the pipeline inlet and the injection well location, there is no need for any intermediate pumping station for the CO_2 to reach the appropriate injection pressure at the wellhead. The maximum pressure at the inlet of the pipeline is 150 bar and the diameter and thickness of the pipe are in accordance with the API5L standard (American Petroleum Institute, 2010). Additionally, there are no major obstacles to pipeline layout in this rural area (neither highways nor rivers).

2.3.3. Injection

The required pressure at the wellhead was calculated considering a 4-in. diameter injection tubing, a thermal gradient of 3.5 °C/100 m, and a depth of 2250 m below ground level for the target aquifer (Keuper sandstones). The initial pressure (in a first approximation i.e. before injection) was assumed to be uniform through the aquifer and equal to the calculated hydrostatic pressure of 225 bar.

As described by Le Gallo in order to avoid geomechanical damage to the reservoir and caprock, it is recommended that the injection pressure not surpass a level 30% above the original hydrostatic pressure. Consequently, with regard to the maximum flow rate, during the injection the pressure at the outlet of the injection tubing within the reservoir must remain lower than 292.5 bar.

For this study, we consider one vertical well to be sufficient to achieve the maximum possible CO_2 flow rate, which is anticipated during the harvest period and described below in the 4th case. Due to the lack of geological data in the studied area, a great uncertainty remains as to the effective local injectivity of Keuper sandstones.

Considering those assumptions, a conceptual project development design and schedule have been performed.

2.3.4. Common infrastructure for two sugar beet refineries

The study also investigated the effect of pooling emissions from the two sugar beet refineries mentioned above so as to reduce transport and storage costs through economies of scale. A shared pipeline and storage site have been designed using the same methodology as previously described.

2.4. Description of the studied scenarios

In order to cover a wide range of possibilities, the Carbon and Energy Footprint (CEF) and Discounted Cash Flow (DCF) assessments were calculated for the following scenarios:

Base case: Ethanol production without CCS (one plant – comparison with Cases 1 and 2, two plants – comparison with Cases 3 and 4)
Case 1: CO_2 capture implemented on the fermentation unit for one plant (yearly average of 45,000 ton of CO_2) with the length of the transport pipeline being 31 km.
Case 2: CO_2 capture implemented on the fermentation and cogeneration units for one plant (yearly average of 100,000 ton of CO_2). "Case 2 bis" (a variant of this case) takes into account the possible improvement of the capture process in the carbon and energy footprint calculation (Rao et al., 2005; MacKinsey Company, 2008). The transport specifications for all of Case 2 remain the same as those in Case 1.
Case 3: CO_2 capture implemented on the fermentation units for two plants (yearly average of 90,000 ton of CO_2), with shared transport facility. The merging point for the two individual pipelines is calculated as 13 km from the first plant (Artenay) and 15.5 km from the second one (Toury).
Case 4: CO_2 capture implemented on the fermentation and cogeneration units for the two plants (yearly average of 200,000 ton of CO_2). The transport specifications for Case 4 remain the same as those in Case 3.

As explained in the previous section only one injection well is needed for those 4 cases, and two monitoring wells are supposed (see Section 3.2.2).

3. Methodology

3.1. Carbon and energy footprint calculation

The goal of our analysis was to quantify the environmental benefits of the implementation of the infrastructure required for the entire CCS chain on a sugar refinery for the different cases described above. In order to achieve this goal, the categories of impacts studied are greenhouse gases production and non-renewable energy consumption. The present study was structured and carried out according to following standards: ISO 14040:2006 (Life Cycle Assessment, Principles & Framework) and ISO 14044:2006 (Life Cycle Assessment, Requirements & Guidelines) up to the point where expert external review of the assessments was required. The Impact 2002+ methodology was used to assess the impacts (Jolliet et al., 2003). This methodology provided equivalence tables relating impacts and substances. The functional unit used in this study is one hectoliter (hl) of ethanol (i.e. 100 l). The general design of the carbon and energy footprint (CEF) calculation is given in Fig. 3.

To estimate the impact of the whole BECCS chain, we first considered the different steps of bioethanol production:

- Cultivation and Harvest of the sugar beets;
- Transportation of the sugar beets to the refinery;
- Operation of the sugar refinery;
- Distribution of bioethanol;
- Consumption of bioethanol.

The data concerning this process were taken from a study conducted by the French Environment and Energy Management Agency (ADEME, 2002), which was updated at the end of 2009. This study assessed the energy and greenhouse gas balances of biofuel production in France.

In order to assess the implementation of a complete CCS chain on a bioethanol refinery, the following facilities were considered by the CEF:

- The CO_2 capture equipment for the cogeneration unit(s);
- The CO_2 conditioning system (compression before transport) for the total amount of CO_2 from the fermentation unit(s) and when applicable the CO_2 captured from the cogeneration unit(s);
- The pipeline transport system (onshore);
- The Keuper reservoir CO_2 injection/storage site(s).

The CEF estimate considers the construction, operation, and dismantling phases of all these facilities. The construction phase consists of steel/cement production and supply, pipeline laying, injection tubing/casing production, and drilling of injection and monitoring well bores, etc. Similarly, the operation phase represents the steam and electricity production required for the capture and conditioning units respectively. Data used in this study were taken in most cases from the "Professional Database" provided within the GaBi4^{TM} commercial software.

3.2. Economic study

3.2.1. Framework

The boundary of the studied system for the economic analysis differs from the CEF's one. It only includes the CCS chain and related utilities but it does not include the different steps of bioethanol production and consumption. The idea here is to analyse the addition

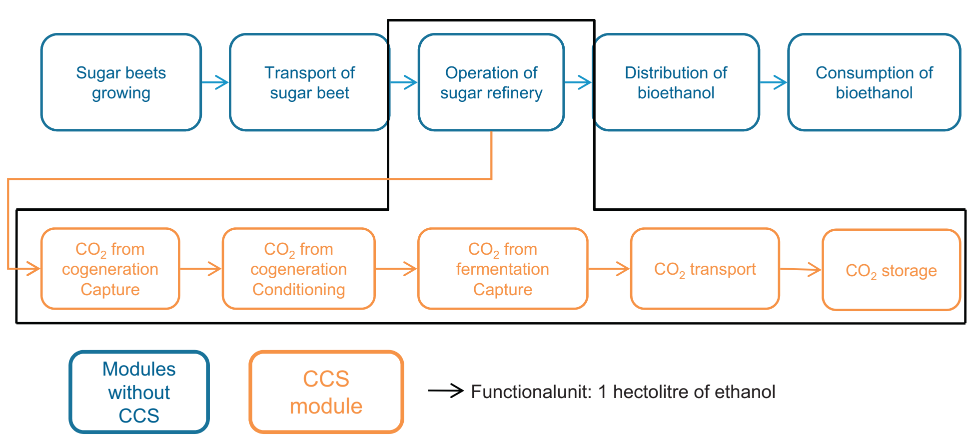

Fig. 3. Scope of the CEF study.

of a CCS chain to existing small bioethanol production facilities. In other words, we want to compare the cost of emitting CO_2 from the cogeneration unit in the business as usual case to the cost of adding the CCS chain on the fermentation unit and/or the cogeneration unit. The aim of this economic analysis was to compute the deterministic net present value (NPV) of the CCS process under different assumptions and scenarios. These NPVs were calculated using the estimated cost of implementing the full CCS chain technology per ton of carbon abated for each case. The net present value is the sum of the discounted cash flows over the lifetime of the project minus the initial investment cost. The NPV of the project can be calculated using the following equation:

$$NPV = \sum_{t=2015}^{2050} \frac{(q_{avoided}(t) - q_{ETS}(t)) \times P_c(t) - O\&M}{(1+r)^{t-2015}} - K$$

where $q_{avoided}(t)$ is the annual quantity of emissions avoided from fermentation (Cases 1 and 3) or from fermentation and cogeneration (Cases 2 and 4), $q_{ETS}(t)$ is the annual quantity of emissions from the cogeneration unit without CCS that are required to be auctioned under the European Emissions Trading System (EU ETS hereafter ETS), $P_c(t)$ is the average annual carbon price on this market, *O&M* are operation and maintenance costs, K is the capital, and r is the discount rate.

Furthermore, the quantities of CO_2 avoided are determined from the quantities of sequestered CO_2 minus the CO_2 emitted as a result of implementing CCS such that:

$$q_{avoided}(t) = q_{seq}(t) - q_{CCS}(t)$$

$q_{ccs}(t)$ includes the annual surplus of emissions due to the CCS chain for each of the cases studied. Table 1 gives the quantity of CO_2 avoided used in the NPV calculation.

The discount rate chosen for the analysis is equal to 4%, which is adapted to long-term investments from the public sector in France (Lebègue report, 2005). The search for high profitability is not necessarily compatible with the main objective of BECCS, because investments aimed at achieving quicker returns might not take into account the potential long term environmental benefits. Nevertheless, a sensitivity analysis has been conducted using a discount rate of 8%, which is more common for the economic evaluation of industrial projects.

Scheduling investments is fundamental for the economic analysis, because they come upfront in the cost schedule, and therefore impact the NPV calculation. Given the time necessary for the site confirmation program (e.g. acquisition of new data locally using seismic acquisitions and drilling investigation wells), and the construction period, the injection is estimated to start in 2020 and continue for 30 years of operation, with an additional 20 years given for post-closure monitoring. Based on this schedule, confirmation investments are assumed as starting in 2015.

3.2.2. The capital and O&M assessment

The purpose of this article is not to provide full detail of the capture, transport and storage engineering. However, cost estimates for transport and storage are based on real conceptual engineering design from CCS industry service provider Geogreen.

Capture: The capture step is only required for the cogeneration unit. The current cost of capital is calculated to be 19 M€$_{2009}$ for the capture equipment needed for one plant's cogeneration unit and designed for the peak flow rate (190,000 ton/year corresponding to an average of 55,000 ton/year). This result is adapted from European study Castor (Abu-Zahra et al., 2007) and brought up to date using Nelson Farrar cost indexes. Given the expected learning curve and technological breakthroughs, this technology should improve both in terms of capital costs and energy saving (natural gas in this case). This cost is assumed to decrease in the range of 12% each time the summed capacity of plants where capture technology is doubles, which is likely to happen by 2013 (MacKinsey Company, 2008). With these learning curves, capture CAPEX are estimated in the range of 12 M€$_{2015}$. However, as the capture O&M fixed costs are not expected to change significantly, we estimated a cost of 0.45 M€/year over the project's lifetime. This includes MEA solvent costs, maintenance (1% of capital) and manpower (1/3 of operating hours at 45€/h charges included).

Compression: The compression investment cost is assumed to be fixed because it is a mature technology. The cost of capital is 5.3 M€ when compression is performed on the fermentation step only and 9 M€ when the boiler emissions are added (from Chauvel (2000) brought up to date by Nelson Farrar indexes). As for capture O&M, the maintenance cost is fixed as 1% of capital.

Transport: Transportation investment costs depend on wellhead pressure, flow rate, compression power, and the distance from the emitter to the storage site. In the cases that consider one plant only, the capital costs are lower because there is less CO_2 carried, with Case 1 (capture on fermentation unit) costing 8.2 M€ and Case 2 10.2 M€. When there are two plants, the cost of capital in Case 3 is 13.1 M€ and 17.7 M€ in Case 4. The cost of O&M is the same for Cases 1 and 2 (0.17 M€), and for Cases 3 and 4 (0.21 M€). Those costs are derived from a MIT study (Heddle et al., 2003) and were adapted to the European context using an in-house factor considering costs from a recently laid pipeline in France and updated to 2009.

As explained in Section 2.3, capture, compression and transport are designed for the maximal flow rate and used only at full capacity during 3 months. This leads to an extra CAPEX of 13 M€ for Case 2 (26 M€ for Case 4).

Storage: As previously mentioned, only one vertical injection well needs to be drilled. In addition, there would be two monitoring wells: one down to the injection reservoir level and one to the sensitive drinking-water aquifer level (500 m depth). Under these assumptions, the cost of capital is 29 M€ and the cost of O&M is 1.3 M€/year. These costs have been calculated following the storage conceptual engineering and design performed during this study (see Section 2.3.3). These costs include exploration/characterization phase (prefeasibility study, seismic acquisitions, drilling of injection and monitoring wells, data logs, production tests, injection tests, administrative engineering and impact and risk studies), operational phase (monitoring wells, surface facilities, operational costs, periodic seismic acquisitions and well work-overs), the post-injection monitoring phase (monitoring, periodic seismic acquisitions and work-overs), and the dismantling phase. Costs are based on European 2009 service rates for seismic acquisition and drilling rigs. The operational, post monitoring and dismantling phase costs are estimates, based on the CCS European directive requirements (Directive2009/31/EC).

3.2.3. Market values modelling and policy

To calculate the NPV, we need to estimate the cash flow and also to make some assumptions about the evolution of natural gas and carbon prices throughout the project's lifetime, as well as to describe the European Union Emission Trading Scheme (EU ETS).

The two main market values taken into account for this economic model are:

Carbon price: The carbon price is strongly influenced by policy and it is very difficult to forecast its evolution for the next

Table 1
Quantities of CO_2 avoided depending on the case study.

	Case 1	Case 2	Case 3	Case 4
Stored CO_2 per year (ton)	45,000	100,000	90,000	200,000
Avoided CO_2 per year (ton)	42,500	80,666	85,000	161,333

four decades. This is particularly true for the European Emissions Trading System (EU-ETS) which has only given details on its rules for its third phase (2013–2020) with some insights up to 2027 (Directive2009/29/EC). In order to be able to use a carbon price model consistent with project host country policy target, we decided to use a recognised French based carbon model (Quinet et al., 2009). This report ordered by the French Prime Minister provides an analysis of the needed carbon price to achieve French environmental policy goals up to 2050.

This model defines a carbon price of 56€/ton in 2020, 100€/ton in 2030 and proposes 3 variations for 2050: a low case scenario at 150€/ton (Low carbon price scenario), a base case scenario at 200€/ton (Base carbon price scenario) and a higher scenario corresponding to stringent target at 350€/ton (High carbon price scenario). Fig. 4 gives an overview of those scenarios.

In order to compare with international carbon price model, this figure also displays the 450 ppm carbon price scenario for OECD countries from the World Energy Outlook 2010 (IEA, 2010a). It corresponds to the price needed worldwide to achieve the 450 ppm maximum CO_2 content in the atmosphere by 2100. One can see that Quinet et al.'s report argues for higher prices than IEA. This can be explained by the regional differences between OECD countries for the carbon price. Indeed, expected ETS in many OECD countries differ widely in terms of offset rules and reduction targets. This is likely to create different carbon prices worldwide. EU-ETS is recognised as the strictest one, which justifies a higher price than for the world average (Türk et al., 2009).

The (EU-ETS) defined a new rule for the distribution of quotas through auctioning for different types of emitters. Power producers will have to buy all their emissions from 2013, while other industrial emitters like in our case study will be subject to a progressive scheme. They will have to buy 20% of their emissions by 2013 on the EU-ETS market, increasing progressively to 70% by 2020 and 100% by 2027.

It is important to point out that biomass CCS is currently not included in the EU-ETS and so related projects cannot benefit from emissions credits. Within the Kyoto framework, CO_2 emissions are accounted differently depending on their origin (e.g. biomass vs. fossil). The regulation that provides guidance for GHG accounting does not consider BECCS as eligible for the first commitment period of the protocol (2008–2012) (Grönkvist et al., 2006). However, to ensure the viability of this project, negative carbon emissions from BECCS must be integrated into new GHG accounting protocols so that BECCS projects can be awarded emissions credit benefits for the technology to be successful (Gronenberg and Dixon, 2010).

Natural gas price: In order to remain consistent with our carbon price approach, we adopted a natural gas price model based on the 450 ppm natural gas price scenario (IEA, 2010a). However, as natural gas prices are not unified worldwide and in order to take into account local specifics, we applied the 450 ppm natural gas price scenario trend to French based retail price for industrial from Eurostat (Goerten, 2009). This base price is 36€/MWh in 2009. This price undergoes then an annual increase of 10% in 2010 down to 6.6% in 2015. Natural gas price rises then at a lower annual rate of around 2.5% up to 2035. We extrapolated this model up to 2050 using the same annual increase.

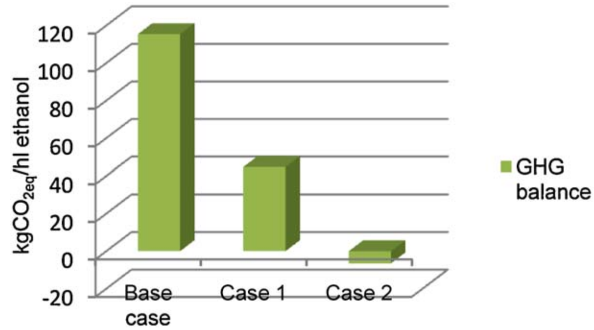

Fig. 5. BECCS GHG balance ($kgCO_2eq$/hl ethanol).

In order to analyse the impact of the implementation of the CCS chain, the NPV project is compared to the NPV of the base case (Business As Usual – BAU) scenario, where nothing is done and where the firm will have to buy CO_2 permits on the EU-ETS market. We make the assumption that a ton of stored carbon is not emitted and so accounts for a carbon credit, whether it comes from the fermentation process or natural gas combustion. Therefore the project is considered economically viable when it allows a reduction of the losses due to permit buying.

4. Results

The results from both the CEF and DCF analyses for the scenarios are summarized in Tables 2 and 3. A comparison of the different cases is reported in Figs. 5–7.

4.1. Base case: ethanol production without CCS

4.1.1. CEF results

The ethanol from sugar beet production process without CCS results in global GHG emissions of 115.4 $kgCO_2$/hl ethanol produced. The non-renewable energy consumption reaches 1683 MJ/hl ethanol. These two major results are notably different from those included in the ADEME-DIREM (2002) study because process efficiency is assumed to be lower in our case (being an existing facility retrofit as compared to a new facility).

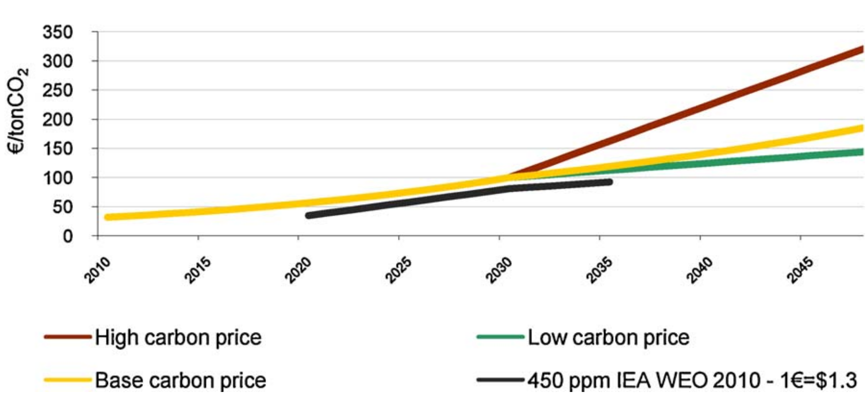

Fig. 4. Carbon prices evolution up to 2050.

Table 2
Carbon and energy footprint main results.

Cases	GHG balance on CCS chain ($kgCO_2eq$/hl ethanol)	Total GHG balance ($kgCO_2eq$/hl ethanol)	Energy balance on CCS chain (MJ/hl ethanol)	Total Energy balance on BECCS path (MJ/hl ethanol)
Base case	X	115.41	X	1683.20
Case 1	4.25	44.66	65.21	1748.41
Case 2	43.85	−6.49	673.85	2357.13
Case 2 with improvement on capture	31.53	−18.81	484.83	2167.63
Case 3	4.28	44.69	65.72	1748.92
Case 4	43.93	−6.41	675.05	2358.25

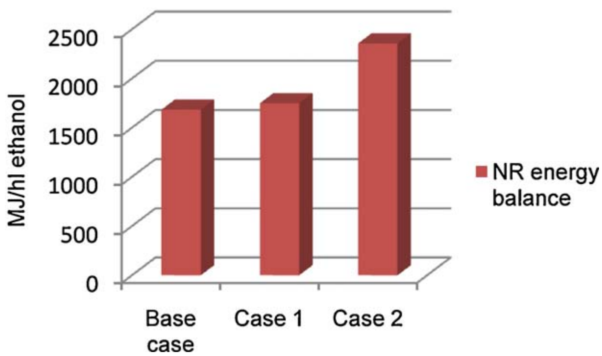

Fig. 6. BECCS non renewable energy balance (MJ/hl ethanol).

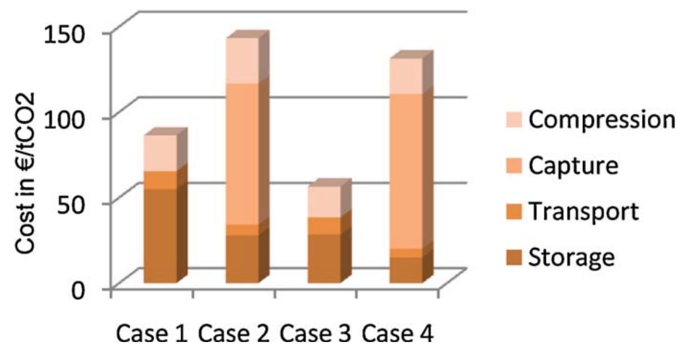

Fig. 7. Cost per ton of CO_2 abated (€/t).

4.1.2. DCF results

In our scenarios, the refinery will have to pay progressively for carbon permits (because of the cogeneration unit) between 2015 and 2027 through progressive auctioning (future EU-ETS regulation). In the BAU scenario, the cost of buying carbon permits depends on our carbon price model. In Cases 1 and 2 (one plant only), the NPV corresponding to permit purchases is −99 M€ in the base carbon price scenario (−92 M€ – Low scenario/−131 M€ – High scenario). In Cases 3 and 4, the results double: −198 M€ for Base scenario (−184 M€ – Low scenario/−262 M€ – High scenario).

Under a stringent policy (High scenario) the project is profitable, since it yields 23 M€. It reduces the losses due to permits purchases from −131 M€ (in the BAU case) to −108 M€. Considering Base carbon price path, implementing the project on the fermentation has no impact on the NPV. However, with Low carbon price scenario the implementation of the CCS chain seems slightly less interesting than not capturing the CO_2 from fermentation (additional loss of 6 M€, from −92 M€ to −98 M€).

4.2. Case 1: capture on fermentation from Artenay

4.2.1. CEF results

The capture process on the fermentation is assumed to be 100% efficient. The net emissions of the BECCS process are reduced by 71 $kgCO_2$/hl (from 115.41 to 44.66 $kgCO_2$/hl), which represents a reduction of 62%. During the 30 years of project operations 1.28 $MtCO_2$ will be abated. The amount of non-renewable energy consumed increases by 4%.

4.2.2. DCF results

The cost per ton abated for the CCS chain with the above economic parameters is equal to 88€/tCO_2: 67% of the cost is due to storage, the compression step accounts for 20%, and the transport for 12% of the total cost.

Table 3
Economic evaluation.

Cases	Cost per ton abated (€/tCO_2)	NPV Low carbon price (M€)	NPV Base carbon price (M€)	NPV High carbon price (M€)
BAU[a] (one plant)	X	−92	−99	−131
Case 1	86	−98	−100	−108
Case 2	143	−164	−162	−151
BAU[a] (two plants)	X	−184	−198	−262
Case 3	56	−149	−153	−169
Case 4	131	−290	−285	−264

[a] The BAU scenario corresponds to the permit buying on cogeneration.

4.3. Case 2: capture on fermentation and on cogeneration from Artenay

4.3.1. CEF results

Capturing CO_2 from the combustion flue gas stream multiplies the GHG emissions addressed by the project ten-fold. Thus, the non-renewable energy consumption due to implementing the CCS chain for most of the plant's CO_2 output also increases by ten, compared to capturing on the fermentation unit alone, which is due to the energy intensive capture process. Nevertheless, this scenario results in the creation of a carbon sink (net removal of CO_2 from the atmosphere) with the whole process resulting in 6.49 $kgCO_2$ being removed from the atmosphere per hectoliter of biofuel produced, which means roughly 3900 ton of CO_2 removed per year. It is important to understand though that this CO_2 removal entails a 40% increase in non-renewable energy consumption. Therefore, a sensitivity analysis of how improvements to the capture process could impact the carbon and energy balance was conducted. These improvements were calculated as reducing the overall heat requirement from 145 kWh/hl to 91 kWh/hl. Ultimately, as the GHG emissions relate directly to the amount of power required, these anticipated improvements to the capture process result in a nearly three-fold increase of CO_2 removed from the atmosphere (18.8 $kgCO_2$/hl net or 11,300 ton/year). This represents more than 10% of overall stored emissions (i.e. 100,000 ton/year). Moreover, this improvement results in an 8% decrease in this scenario's non-renewable energy consumption.

4.3.2. DCF results

The costs per ton avoided are higher than in the first case at 143 €/tCO_2. The main cost here is the cost of implementing capture on the boiler (58%), with compression accounting for 19%, transport 4%, and storage representing 19% of the total cost.

As a result, under these conditions this scenario cannot be justified economically. Compared to the base case (BAU) and even considering the High scenario the losses are around 20 M€, from −131 M€ to −151 M€ (loss of 63 M€ – Base scenario/loss of 72 M€ – Low scenario).

4.4. Case 3: capture on fermentation from two plants

4.4.1. CEF results

In the third case, the volume of CO_2 considered is doubled compared to Case 1. As the construction phase has a low impact on the CEF, in the end implementing capture technology on one or two fermentation units does not change the carbon balance of the project. In terms of GHGs, the net emissions are reduced by 71 kgCO_2/hl ethanol (from 115.41 to 44.69 kgCO_2/hl) while the amount of non-renewable energy consumed is almost the same as in Case 1.

4.4.2. DCF results

Pooling the emissions of the two plants allows for a decrease in the transportation and storage costs resulting in a cost per ton abated of 57€/tCO_2. The storage part accounts for 50% of the total cost, while transport makes up 18% and compression 32% of that cost.

In this case, the project becomes profitable regardless of the studied carbon scenario. When considering the Low scenario, the savings due to implementing CCS are around 35 M€, compared to the BAU scenario (−149 M€ vs. −184 M€). If the Base or High scenarios are taken into account, the savings are even higher respectively 45 M€ and 93 M€ (−153 M€ vs. −198 M€ – Base scenario/−169 M€ vs. −262 M€ – High scenario).

4.5. Case 4: capture on fermentation and cogeneration from the two units

4.5.1. CEF results

As the operation phase has much more impact on the balance than the construction phase, the GHG balances for BECCS in this case are similar to those found in Case 2 because increasing the production volume does not have any real effect on the balance.

4.5.2. DCF results

As many costs relating to storage are not depending on the stored volume, the cost per ton abated is lower in this scenario than in Case 2 (131€/tCO_2), due to the larger volume of CO_2 sequestered. Here capture and compression account for around 85% of the cost, while storage is responsible for only 11% and transport comprises 4% of the total cost.

The decrease of transportation and storage costs per ton due to economies of scale results in an equivalence of the BAU and the CCS scenario when considering the High carbon price (−262 M€ – BAU and −264 M€ – Case 4). However, the losses increase respectively of 87 M€ and 106 M€ in the Base and Low price scenarios.

4.6. Sensitivity analysis on natural gas price

A sensitivity analysis was performed on the natural gas price for the case where gas is used the most, that is to say Case 4: CCS implementation on fermentation and cogeneration on Artenay and Toury. For this case the NPV is equal to the BAU's one only if High carbon price scenario is considered. If the natural gas price following the IEA 450 ppm gas scenario increases by 20%, the total NPV decreases by 17% and the project is no longer viable on the economic standpoint (Natural gas price 450 ppm – Case 4: −264 M€ compared to −306 M€ when the natural gas price is increased by 20%).

4.7. Sensitivity analysis on the discount rate

As was discussed previously, the cases were all recalculated using a discount rate of 8% instead of 4%, which is more typical for general industrial projects. A higher discount rate largely penalizes this kind of project and the end results have shown that with this kind of economic assumption, it is more difficult to achieve an economically viable CCS chain implementation on small retrofitted bioethanol production units. Indeed, the CCS chain implementation presents an interest only when CCS is added to the fermentation units of both sugar beet refineries (Case 3) and considering high carbon prices (10 M€ in favour of Case 3 as compared to BAU).

This highlights the fact that, in the Artenay case where small volumes are captured, the pooling of emissions is a key element to achieve sufficient cost dilution and economic return.

Moreover, considering the CCS chain investment as public (4% discount rate) allows the project to be viable. As the volume implied is not able to dilute sufficiently investment in capture and storage (share of storage in total cost can reach as far as 50% – see above), one can wonder about the impact of government subsidies on the economics of the project.

4.8. Public funding effect on the economics

Here we considered the impact of direct public investment into the project corresponding to 25% up to 50% of initial CAPEX. This level of funding is in the range of EU investment in project. For example, maximum 50% of eligible costs are funded under the European funding mechanism NER 300 (EU – NER 300, 2010). Table 4 shows the Internal Rate of Return (IRR) for the CCS chain implementation. This corresponds to the discount rate when both BAU and CCS project lead to the same NPV result.

When the Base carbon price scenario is considered, taking into account a public funding reaching 25% of the initial investment corresponding to 10 M€ for Case 1 and 15 M€ for Case 3 enhances the robustness of the project (greater IRR from 4% to 5.5% for Case 1 and from 7.5% to 9% for Case 3). However, even with 50% of public funding, the equivalence in losses is never reached when implementing CCS on the fermentation and on the cogeneration units (Cases 2 and 4). What is also important to point out is that, if the High scenario is applied, Cases 2 and 4 can reach an internal rate of return of respectively 3.5 and 5% with 25% of public funding (that is to say 14 M€ for Case 2 – 22 M€ for Case 4).

5. Discussion

5.1. Discussion on the CEF results

One notable result from the CEF analysis in this case study was that the operation phase (capture and conditioning) has the highest environmental impacts. Therefore, if the biofuel production volume considered is increased (e.g. in this study doubled for Cases 3 and 4 with two units instead of one), the end results for the carbon and energy footprints are approximately the same (varying less than 1.5%) per hectolitre of ethanol produced.

On the other hand, CEF was demonstrated to be very sensitive to what capture solution is implemented. While Cases 1 and 2 differ in terms of CO_2 volumes, the important distinguishing factor is more precisely that Case 2 implements capture on the cogeneration unit. When we consider the CEF of the CCS chain for these two scenarios, the CO_2 emissions and the non-renewable energy consumption are

Table 4
Internal rate of return of the CCS implementation (i.e. Equivalent NPV between BAU and CCS project).

Carbon price	% public funding	Case 1 CCS on fermentation – one unit	Case 2 CCS on fermentation and cogeneration – one unit	Case 3 CCS on fermentation – two units	Case 4 CCS on fermentation and cogeneration – two units
Base carbon price	0%	4%	–	7.5%	–
	25%	5.5%	–	9%	–
	50%	7.5%	–	11.5%	–
High carbon price	0%	6%	2.5%	9%	4%
	25%	7.5%	3.5%	11%	5%
	50%	10%	5%	13%	6%

ten times higher in Case 2 than in Case 1, largely due to the added capture process. Specifically, the CO_2 is separated from other gases using an amine solvent, which needs to be regenerated by heat to release the captured CO_2. This energy consumption results in GHG emissions. The compression step also requires more energy as there is more CO_2.

Ultimately, capturing, transporting, and storing CO_2 from the cogeneration unit increases non-renewable energy consumption in the case we use fossil fuel energy to generate the heat necessary for amine regeneration. However, the stored volume of CO_2 is more important. The whole lifecycle for bioethanol production/consumption coupled with CCS must be examined for each case so as to establish, in terms of CEF, whether it is interesting to implement capture on the cogeneration unit or not.

If the CO_2 from the fermentation process only is captured (for one or two units), the GHG emissions are reduced by 62% from BAU (bioethanol production and consumption), with the CCS chain representing only 3.8% of the total non-renewable energy consumption during the biofuel production/consumption lifecycle. If the CO_2 from both the fermentation and cogeneration processes is captured (for one or two units), the net result is a negative balance of GHG in the atmosphere. It means the project removes CO_2 from the atmosphere. Moreover, when technological improvements on the capture process are considered, for each hectolitre of ethanol produced, 18.8 kg of CO_2 is removed from the atmosphere as compared to business as usual bioethanol production consumption which in this case emits 115.4 kg of CO_2. In other words, more than 130 kg of CO_2 are not emitted per hectolitre of bioethanol produced. However, a 30% increase of total non-renewable energy consumption is required to reach this "carbon negative" option.

To deepen this analysis, it was important to compare our results with the CEF (i.e. the GHG and non-renewable energy balances) of regular oil production and consumption required to produce/consume the typical petroleum fuel (gasoline). For this purpose, we used the ADEME (2002) study and the results of the comparison are reported in Table 5.

First, it is important to note that even with CCS implemented on both the cogeneration and fermentation processes, the non-renewable energy balance is still in favour of bioethanol production/consumption compared to regular gasoline. Second, it becomes clear that although the capture of CO_2 on fermentation unit alone is not a "carbon negative" option, it is still interesting in terms of its climate implications as it allows a GHG emissions reduction of 61% for the plant. Finally, the results from the GHG balance analysis underline that given the studied BECCS system, biofuels are demonstrated to be an effective means for achieving GHG reductions and this should help assuage the controversy regarding their carbon neutrality. This is further emphasized as the entire process, when properly implemented under the right conditions, can remove CO_2 from the atmosphere Nevertheless, the GHG balance should not be the only parameter taken into account. For each case study, the optimal solution is a balance between the GHG reduction efficiency and the resulting non-renewable energy consumption. On a side note, it is important to remember that this study considered the cogeneration unit to be natural gas-fed. However, if biomass were to replace the natural gas feedstock for this process, the non-renewable energy balance will significantly be improved (First rough calculations show a decrease between 12 and 18% of the non renewable energy balance for the complete bioethanol cycle when CCS is applied on fermentation and cogeneration) and the created sink will be larger than when the cogeneration is fed with natural gas as the emissions coming from the cogeneration will be included in the neutral cycle of the biomass. An additional study should be performed to look thoroughly at the benefits in terms of GHG emissions reduction but a first assessment leads to a removal from the atmosphere of 80,000 tCO_2/year for Case 2 all other factors being unchanged (calculation made with data from Sebastiàn et al., 2010 and Gasol et al., 2007 using *Brassica carinata* for biomass). Firing the cogeneration with biomass leads if the CCS chain is implemented on fermentation only (Case 1) to a net removal of CO_2 from the atmosphere of about 28,000 tCO_2/year.

5.2. Discussion on the economic results

One of the main advantages of this study is that it highlights the low capture cost for the biomass fermentation process (Cases 1 and 3), as capture only consists of compression. This high CO_2 concentration source could represent an early opportunity for the implementation of CCS. In Case 1, the cost of compression is equal to18€/tCO_2 abated and accounts for less than 25% of the total cost compared to Case 2 where the capture on the boiler and the

Table 5
Comparison between oil, bioethanol and bioethanol with CCS – energy and carbon balance.

Cases	Regular oil production and consumption	Bioethanol production and consumption	Bioethanol production and consumption CCS on fermentation unit	Bioethanol production and consumption CCS on fermentation and cogeneration unit
GHG balance (gCO_2eq/MJ)	85.9	54.5	21.25	−9
Non renewable energy balance (MJ/MJ)	1.15	0.79	0.83	1.04

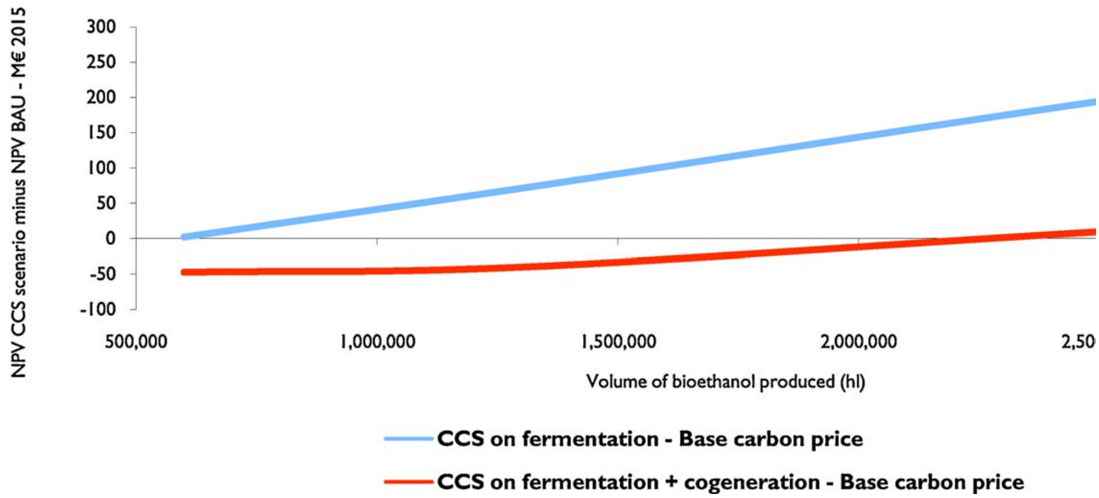

Fig. 8. Sensitivity of the economics to the volume.

compression account for 76% of the total cost (about 109€$_{2009}$[1]). However, the costs presented in this study remain significant, notably when compared to those obtained by Möllersten et al. (2003) from their analysis of the sugarcane ethanol production (which calculated a price of around 50$/t$CO_2$ for the capture and compression of CO_2 from both the fermentation and cogeneration steps). However, this discrepancy is largely due to the specificity of this study, which is focused on very small retrofitted biofuel operations. In the Möllersten study, they deal with a mean annual production of 3 million/hl as compared to the 600,000 hl in this study. A key problem for this study is that the investment costs (e.g. a large, fixed storage cost) are adversely affected by poor economies of scales. Furthermore, the significant variability in the CO_2 emission volumes during one year (due to the production peak during the sugar beet harvest) requires the CCS units to be built at sufficient scale so as to handle the maximum expected production volume.

The transport and storage CAPEX does not vary significantly between the different cases studied (because of high injectivity supposed in the considered reservoir and the short distance pipeline). This is a major burden for the project economics. Thus, in order to enhance economies of scale, one solution was envisioned in this study. We considered in Cases 3 and 4 the pooling of emissions from two small local emitters. This highlights the advantage of a trunk pipeline system and common storage site connecting the sources. Indeed Cases 3 and 4 present lower cost per ton of CO_2 abated than Cases 1 and 2. If we follow on the pooling track, we could consider other emitters in the vicinity of those refineries. There are some small nearby emitters that could be interested in storage opportunities but they do not present the early opportunity capture profile. However, many big industrial emitters like oil refineries are present at the north of the plants. This has to be further studied in order to be certain of the real benefit that it could represent.

Another key factor that was highlighted by the study is the importance of environmental policy. First, the CO_2 from fermentation must be regulated in order to create the incentive needed to inspire the deployment of this type of project. We believe that in terms of short-term policy considerations, one ton of avoided carbon via BECCS should be considered as not emitted and count for one carbon credit unit, just as with fossil fuel-based CCS.

Secondly, the long-term carbon policy trend is also an important factor for this type of project. We have demonstrated that the project can be profitable only if a strong political agreement constraining GHG emissions is applied with BECCS technology clearly being more attractive under Base and High carbon price scenarios which consider stricter emission reduction target for France. This result is in line with a significant amount of literature that arguing that BECCS is one of the key possible mitigation solutions that need to be implemented in order to reach such a low stabilisation target (Azar et al., 2010; IEA, 2010b).

The selection of the discount rate is a key driver to determine whether the project should be implemented or not. Using the 4% discount rate that is attributable to French public investment, the project is able to achieve economic success when CO_2 is captured on fermentation. When considering capture on fermentation and cogeneration with sufficient volume (Case 4), equilibrium could be reached for the project.

On the other hand, the 8% discount rate employed for the sensitivity analysis indicates that the project is viable only when the capture is performed on fermentation (low cost capture) on both refineries (higher volume).

In any case, investments in BECCS projects need to be evaluated also from a public perspective in order to take into account the potentially implied mid- and long-term environmental effects that could result from not engaging in this type of project.

When pointing out the need to evaluate the project from a public perspective (low discount rate), we can imagine also a direct investment from public authorities into the project. This is particularly justified by the fact that small emitters may not have the financial strength to carry out such an heavy investment with long return. With direct public funding corresponding to 25% of investment and in Base carbon price scenario the economic performances of capturing CO_2 on fermentation (Cases 1 and 3) are enhanced from an Internal Rate of Return of 4% without funding up to 9% when 2 fermentation units are considered.

Only when there is a stringent policy resulting in high carbon prices and a public funding of at least 25%, capturing on fermentation and cogeneration could reach the 4% Internal Rate of Return.

This public investment is quite limited (up to 20 M€ for Case 4) if we compare to the recent award of 45 M€ by French environmental agency Ademe for four 6–8 years projects.

[1] The corresponding deflated cost in 2003 is 97€ with an average exchange rate 1€= 1.1392US$ in 2003 the cost in US$ is 110US$.

Finally the last key point to enhance the economics of this project lies in the increase of the volume of bioethanol produced by each unit. This is easily achievable by switching the sugar proportion produced by the refineries but also by increasing the plant capacity. In order to look at the impact of such a capacity increase, we performed a preliminary sensitivity analysis on the volume from Artenay current capacity 600,000 hl/year to the capacity of a similar existing bioethanol refinery located in the western part of France and producing 3,000,000 hl/year (Fig. 8).

This short analysis highlights that while increasing the volume of bioethanol produced, the economics for CCS on fermentation on one refinery becomes stronger. Furthermore, we can reach economic equilibrium when capturing on fermentation and cogeneration for volumes of bioethanol produced greater than 2,500,000 hl/year. It further stressed the interest of BECCS on bioethanol from sugar beet with higher production capacities.

6. Conclusion

Even with small volume concerned and considering the retrofit of an existing facility (less possible process optimization), the Artenay BECCS project showed that capturing CO_2 on sugar beet bioethanol production is a good early opportunity for CCS deployment under certain circumstances. Among them, National and European Authorities have to seriously consider the possibility to monetize stored carbon credit from biomass, and assure a high enough long-term carbon price through clear political signal(s).

Capturing and storing CO_2 from fermentation only with cogeneration fired with natural gas improves the carbon footprint of bioethanol production and consumption by 60% without increasing much the non renewable energy consumption. Additionally the overcost due to capture, transport and storage is almost always smaller than overcost due to quotas purchase, in a public investment context and with the carbon price scenarios considered in this article. Firing the cogeneration unit with biomass can even generate a net removal of atmospheric CO_2 (27,000 ton of CO_2/year for one plant considered), while also massively decreasing the consumption of non renewable energy.

Capturing and storing CO_2 from fermentation and cogeneration is even more appealing from a carbon footprint stand point and creates an artificial CO_2 sink: it removes CO_2 from the atmosphere (as demonstrated in Cases 2 and 4 of the CEF study). The carbon footprint of bioethanol production and consumption is improved by 115%. However, it increases non renewable energy consumption by 40%. This could be easily reduced by using biomass as fuel for the heat and electricity generation. The net removal of CO_2 from the atmosphere in this case is about 80,000 tCO_2/year for one plant. On the economic standpoint, the only way to achieve economic equilibrium with Business As Usual scenario for such small sources is to be in a public investment context (4% discount rate) with a stringent carbon policy (High carbon price scenario) and direct subsidies corresponding to 25% of CAPEX.

This article stressed out the fact that public authorities have to be involved into these types of early opportunities projects by providing financing support to small emitters, so enabling significant projects rates of return. We also underlined that transport and storage cost dilution can be realistically achieved by clustering emissions from various plants located in same region. On a single plant project basis, increasing bioethanol production can also produce strong economies of scale.

As there are many bioethanol refineries in Europe similar to the Artenay case, the positive results of this article encourage additional research to investigate the synergies and benefits of BECCS with current European CCS strategies.

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