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From Geology to Economics: Technico-economic feasibility of a biofuel-CCS system.

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Abstract

This paper presents a method to estimate the technical and economic feasibility of capturing and geologically storing CO_2 resulting from biomass fermentation. The methodology is applied to the case of bio-refineries in the Paris Basin, France. The first step is to build a 3D geological model of the area studied and to choose the optimal injection location from geological and environmental constraints. Then, based on this information, the design of the CCS system (pipeline length, number and type of wellbores, surface equipment …) and the estimation of the technical feasibility (sufficient storage capacity, risk analysis and management …) can be performed. The last step is the estimation of the environmental benefits of this system (through a carbon and energy footprint) and its economic long term feasibility thanks to a discounted cash flow analysis. The impact of geological constraints on the economic feasibility of the system is estimated through a sensitivity assessment on the number of required injection wellbores.

Keyword : CO2 ; Biomass ; Site selection ; Carbon and Energy Footprint ; Storage Design ; Economics

1. Introduction

The Biomass-CCS systems consists in capturing and storing CO_2 stemming from biomass transformation or exploitation. Several industrial sectors could be investigated like the paper industry, the electric sector, or the biofuel sector. According to Kheshgi and Prince [1], this last option called BECCS (Bio-Energy Carbon Capture and Storage) can potentially contribute to a net greenhouse gas (GHG) emission reduction, given that CO_2 from biomass is considered neutral. Moreover the IEA CCS Roadmap [2] emphasizes that this system has the global potential to store about 2 Gt of CO_2 by 2050, assuming that biofuels could account for 26% of the total transport fuel demand.

As previously mentioned in Bonijoly *et al*, [3], the general scope of the CPER Artenay project is to identify the geological and technical factors that lead to a profitable and GHG efficient Biomass-CCS project.

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Within the scope of the project, the purpose of this paper is to present a methodology to assess the technical and economic feasibility of the capture and storage of CO_2 emitted from biomass fermentation. The study is based on real data coming from a sugar beet ethanol plant located in France.

2. System description

2.1. Study area location

The study area is located within an area of 900 km² in the southern portion of the Paris Basin, close to Orléans. It is a highly attractive region thanks to its favorable capability to match sources and sinks. Indeed, two sugar beet refineries are located at short distance from two major deep saline aquifers (the Dogger and Keuper formations) that could be suitable for CO_2 storage.

2.2. Refinery description

For the purpose of the study, only carbon emissions linked to bio-ethanol production are considered. Then the simplified sugar refinery scheme shown on Figure 1 depicts the two considered CO_2 sources for capture: the cogeneration unit fed with natural gas (“fossil” CO_2) and the fermentation unit (“biomass” CO_2). However, all CO_2 sources, including emissions related to sugar beet harvesting and transport, and so on, are taken into account in the carbon balance of the system.

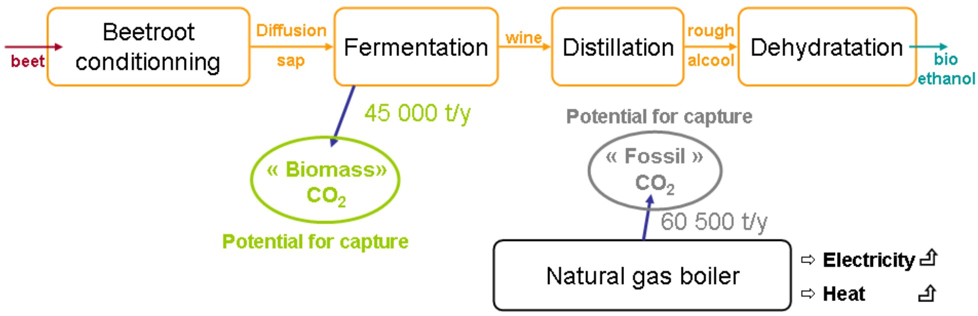

Figure 1: Schematic representation of the items considered in this study to describe the bio-ethanol production.

Each of the two refineries considered in this study produce 600,000 hl of bio-ethanol per year. For this production, the volumes of CO_2 emitted per source are: 45,000 t from the fermentation unit and 60,500 t from the cogeneration unit. These yearly volumes are quite small, but the CO_2 emission rate is not constant during the year. As illustrated in Figure 2, during the three months of the harvest period (October to December), the production of bio-ethanol and thus CO_2 emissions are about three times higher than for the rest of the year (two fermentation tanks are used during the campaign, while only a smaller one is used otherwise).

2.3. Capture strategy

The stream coming from the fermentation unit is mainly composed of CO_2 (about 85%), O_2 and N_2. However, in this preliminary study, we assume it is composed of 100 % CO_2. This corresponds to an ideal anaerobic fermentation where each mole of glucose creates one mole of ethanol and one mole of carbon dioxide. Consequently, only compression is needed before transport and storage.

No specific measurement has been made to determine the composition of the stream coming from the co-generation unit (fired with natural gas). However it seems reasonable to follow the generic assumption that CO_2 is diluted (around 8 vol%) in mostly nitrogen.

Under these assumptions, the study from Laude *et al,* [4] emphasizes that, due to the small volume considered here, the capture of CO_2 from the cogeneration unit ("fossil" source) is not economically profitable. Consequently, only the capture of CO_2 from the fermentation unit is considered in the following parts of the study.

Moreover, we only consider here the most economically efficient scenario, which consists in gathering CO_2 coming from the two close distilleries with similar feature, which leads to the capture of 90,000 t per year of CO_2 from biomass fermentation.

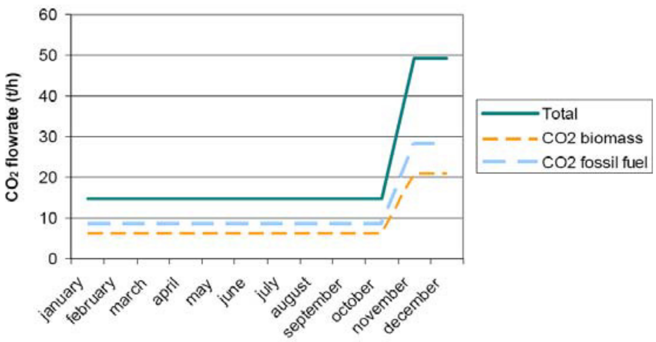

Figure 2. CO_2 emission rate variation for the refinery considered in this study.

3. Technical issues

3.1. Step 1 : Geological characterization

The first step of the methodology is to build up a conceptual geological model with a particular challenge for 'deep aquifer' storage due to the scarcity of available data. The approach used is based on the interpretation of 300km of seismic lines combined with an integrated study (sedimentology, sequence stratigraphy and geostatistic simulations) of more than 50 wellbores data. Three major normal faults crossing the area were identified, among which the Sennely fault affects all formations from the basement to the Lower Cretaceous. The layers are nearly sub-horizontal, except close to the faults where bends (drag folds) are observed. The overall description of the geological characterization methodology is reported in [5].

This study emphasizes that the Dogger aquifer is either not deep enough for CO_2 storage, or exhibits poor/average reservoir properties within the study area. On the opposite, the Triassic aquifer located at the South-East of the Artenay refinery should be an interesting storage location, with a high average permeability (around 500 mD i.e. 5.10^{-13} m²) and effective thickness (i.e. thickness times Net-to-Gross) higher than 20 m.

However this work is a pre-feasibility study and significant uncertainty remains with regards to the petrophysical characteristics of the studied reservoir.

3.2. Step 2 : Injection point selection

The next step of the study is the determination of the optimal injection point. This determination is made following the methodology initially developed by Grataloup *et al.*, [6]. It starts with the combination of "killer criteria" to exclude areas where CO_2 injection should not be possible: the vicinity of potential leakage pathways (existing wellbores, faults), permit areas for hydrocarbon or geothermal exploration and exploitation, environmental restriction areas, populated areas or the spatial footprint of major surface facilities such as roads or railways. Then, the optimal injection point(s) is (are) identified from the remaining zones through the combination of "site qualification criteria" (better storage capacity and injectivity, cheaper CO_2 transportation…). The combination of some of the criteria (killer criteria or site qualification criteria) in a Geographical Information System (GIS) is reported in Figure 3.

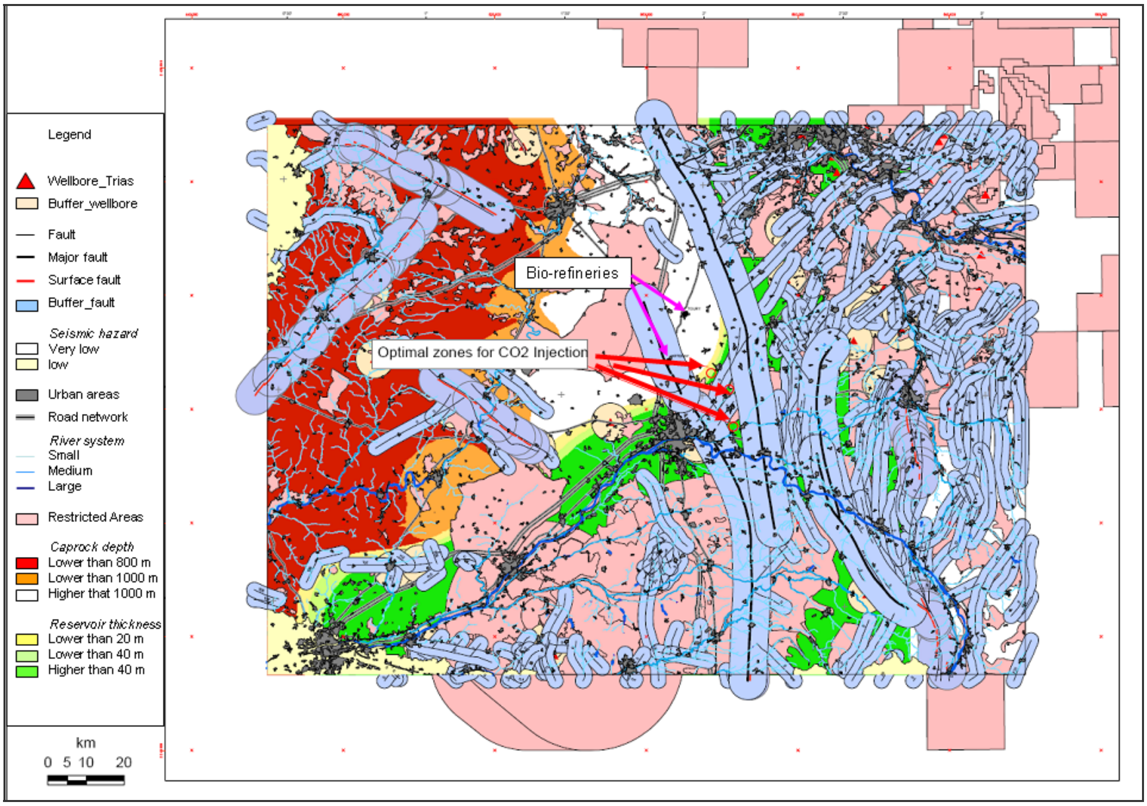

Figure 3 : Determination of the optimal injection zones from a GIS analysis

For this study, the buffer distance around potential leakage pathways was fixed by an expert panel in the light of preliminary flow simulations. These resulted in an order of magnitude plume extent lower than 10 km^2 for dissolved CO_2 within the Triassic sandstone aquifer after 30 years injection and 30 years post-injection. To ensure an optimal injection site selection, the width of buffer zones around potential leakage pathways should be re-evaluated for each project, depending on the amount and flow rate of CO_2 injected and considering the geological and hydrogeological characteristics of the target formation.

3.3. Step 3 : Transport and Storage design

After determining optimal injection zones, more detailed flow simulations can be run to estimate injectivity, the extent of the CO_2 plume and the overpressure within the open aquifer after 30 years injection. Based on these results, the choice of the most suitable injection point within the zones (selected during step 2) is optimized according to the site qualification criteria in order to ensure the safest operational conditions.

The next step is to design the pipeline network, the wellbores (injection/monitoring), and the surface facilities.

The transport is realized by pipeline, with CO_2 in a dense phase. Because of the short distance (around 30 km) and of the absence of elevation differentials, there is no need for any intermediate pumping stations for the CO_2 to reach the wellhead at an appropriate pressure for injection. Furthermore, the injection location is determined in a way to avoid the crossing of significant obstacles such as highways or important rivers. The pipeline outlet pressure at the injection well is equal to the injection pressure required at the wellhead. The maximum pressure at the inlet of the pipeline is 150bar. The diameter and thickness of the pipe are in accordance with the API5L standard.

For the injection step, the pressure at the wellhead was calculated considering a 4” tubing (with a thickness of 5.7 mm) and a thermal gradient of 3.5°C/100m. The Keuper aquifer is 2250m deep, and in a first approximation, its initial pressure (i.e. before injection) is supposed to be homogeneous and equal to 225 bar (hydrostatic pressure).

To avoid any mechanical damage, the maximum injection pressure is estimated to be 30% higher than the hydrostatic pressure. Consequently, for the maximal flow rate, the pressure at the wellbore shoe during injection should be 292.5 bar. Under the assumption of this preliminary study, one sole injection wellbore was found sufficient for injecting the 90,000 t of CO_2 per year, which corresponds to a maximum flow rate close to 350,000 t/y during the harvesting period.

However, as written previously, significant uncertainty pervades the geological characterization of the site. In particular, from wellbore data analysis, the permeability of the Triassic aquifer can vary, from 10 mD (10^{-14} m²) to 1D (10^{-12} m²) within the study area. For lower values in this permeability range, additional injection wellbores may be needed to inject the same flow rate of CO_2. Then a sensitivity test on the required number of wells was performed and the economic profitability of the system was scanned considering either one or two injection wellbore(s).

3.4. Step 4 : Risk management

The selection of the injection point realized during step 2 is not sufficient to ensure permanence and safety of the storage. An assessment of relevant risks should be carried out and a risk management plan developed for the site. The methodology established within the CRISCO2 project [7] was used here. It is based on the assessment of the potential effects of risk events, judged relevant by an expert panel, given the results of the previous geological characterization, the results of the dynamic simulations and the analysis of a number of maps of the site showing the vulnerability of the environment, external hazards, etc. The potential exposure of vulnerable assets resulting from these risk events is estimated and safety requirements are deduced from its comparison to critical thresholds. This methodology focuses on simple, but realistic physically-based modeling and addresses uncertainty management. It is worth underlining that risk assessment for a BECCS system needs to take into account the associated compounds in the flue gas, which are significantly different from the case of fossil fuels CCS, i.e. Volatile Organic Compounds, acetaldehydes, and oxygen.

Considering the localization of the injection point, a few risk scenarios like leakage through an abandoned wellbore or fault reactivation were examined, while others such as fracturation induced by a natural seism were not. A more extensive description of this step and of the results obtained for several case studies should be developed in a further publication.

4. Economic and environmental assessment

To quantitatively assess the interest of BECCS, a carbon and energy footprint and an economic analysis were performed from the technical results from the previous steps. The overall description of the method used here is reported in [4].

4.1. Step 5: Carbon and Energy Footprint (CEF)

The CEF analysis aims at quantifying the environmental benefit when implementing the entire infrastructure required for CCS on a sugar refinery. To this end, the studied indicators are greenhouse gas production and non-renewable energy consumption.

The whole system is considered for this CEF, from the sugar beet growing to fuel consumption, as well as considering a construction, an operation and a dismantling phase for the facilities.

The CEF was structured and carried out following the current standards [8, 9]. The external expertise required by these standards has however not been conducted. The impacts were assessed using the Impact 2002+ methodology. It gives tables of equivalence between impacts and substances.

The data for bioethanol production and consumption come from the ADEME/DIREM 2002 study and from data provided by a local sugar and ethanol producer located in Artenay.

The streams coming from the fermentation unit and from bio-ethanol consumption are assumed to be pure and carbon neutral. Indeed all of the carbon dioxide produced during these steps corresponds to carbon dioxide that was previously absorbed by the sugar beets during photosynthesis. It is thus included in the natural carbon cycle and does not contribute to the greenhouse effect (for a larger description of the carbon and energy balance see Laude et al [4]).

Results reported in Table 1 emphasized the great environmental benefits of this system. Indeed, CO_2 emissions for fuel production and consumption can be cut by 75 % when compared to regular fuel and by 61% when compared to classical bio-ethanol. Moreover, only a slight increase of non renewable energy is needed to implement the CCS chain on the bio-refinery (+5%). This system then allows reducing demand in non renewable energy by 28% in comparison to the use of regular fuel.

As previously discussed by Laude *et al.* [4], capturing and storing both CO_2 from biomass and from the cogeneration unit would be needed to achieve negative emission. However this system was found to be hardly economically viable for the small volume considered here.

Table 1. Results of the CEF analysis and comparison with the production and consumption of 1 MJ of either bioethanol without CCS, or of regular fuel.

	Regular fuel production and consumption	**Bioethanol production without CCS and consumption**	**Bioethanol production and consumption with CCS on fermentation**
GHG Emissions (gCO_2eq/MJ)	85.9	54.5	21.25
Non renewable energy consumption (MJ/MJ)	1.15	0.79	0.83

4.2. Step 6: Economic analysis

Based on the environmental results from the previous steps, the economic analysis aimed at deciding if the BECCS project must be undertaken. The decision rule used for comparing the costs and benefices of the project is the net present value (NPV). The NPV is the difference between the sum of the discounted cash flows which are expected and the amount which is initially invested. If the NPV results in a positive amount, the project should be adopted.

Consequently, an estimate of the cash flow is needed as well as assumptions on the evolution of gas and carbon prices throughout the project's lifetime. As previously underlined by the IEA outlook in 2008 [10], carbon price should be strongly influenced by policy. To scan this effect, we chose two scenarios based on the two major political targets: 550ppm or 450ppm maximum CO_2 content in the atmosphere in 2100. In the first scenario, the price per ton of CO_2, as foreseen by the IEA, is assumed to be 30€ by 2020 and 65€ by 2030. In the second case, the measures taken after 2020 are more restrictive, so that, while the price per ton remains 30€ in 2020, it is projected to increase to 130€ by 2030. After 2030, marginal abatement costs are supposed to decrease thanks to new technologies so that carbon prices tend to slowly decrease (see [11]).

To ensure the viability of this project, biomass avoided emissions with CCS need to be integrated into new GHG accounting protocols so that BECCS projects can be awarded emissions credit benefits for the technology to be successful. Therefore we assume that a ton of avoided CO_2 thanks to BECCS accounts for a carbon credit in the European Trading System.

For the case considered in this study, the cost per ton of CO_2 abated is 57.4 €/tCO_2, where, as reported in Table 2A, storage accounts for 50% of the total cost, transport for 13% and capture for 37%. This uncommon cost repartition can be explained by the fact that, in this BECCS system, the CO_2 stream is almost pure and the distance between the refineries and the storage location is relatively short (lower than 30 km).

Table 2. Repartition of the cost of CCS applied on the fermentation unit only and considering the match of the Toury and Artenay sources. (A) stands for the base injectivity case and (B) for a lower aquifer injectivity that leads to an additional injection wellbore.

Cost per ton of abated carbon	Capture (%)	Transport (%)	Storage (%)	Total€/tCO2eq
One injection well (A)	37	13	50	57
Two injections wells (B)	22	11	66	91

The profitability evaluation, reported in Figure 4, emphasizes the importance on the environmental policy stringency. In the 450 ppm policy the investment yields 60 M€ in profits after 30 years injection. However in the 550 ppm policy it only yields 3M€

The impact of an additional wellbore on the cost per ton of carbon abated is shown in Table 2B. With a 60% increase in this cost, the influence of the number of injection wells required, and thus of transmissivity (i.e. permeability times effective thickness) of the target reservoir, on the project cost structure can be easily seen. In this case, as sketched in Figure 4, the project profitability is drastically reduced and even becomes strongly negative for a 550 ppm policy.

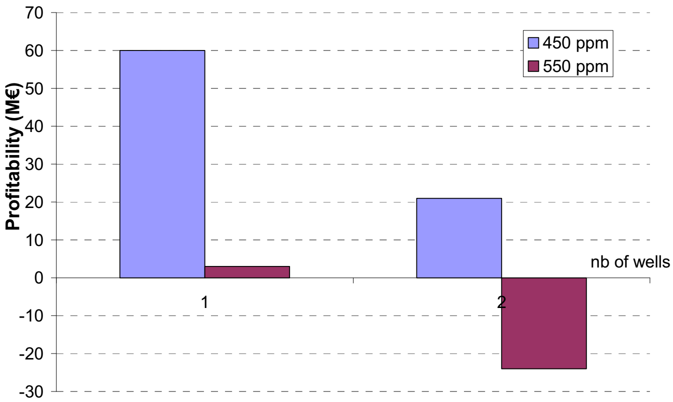

Figure 4: Estimation of the economic viability after 30 years of injection of the studied BECCS systems as a function of the number of injection wells and of the policy.

5. Concluding remarks

In this paper, we have presented a step-by-step methodology to estimate the technical and economic feasibility of capturing and storing CO_2 resulting from biomass fermentation. The steps identified are:

- Step 1: Geological characterization and 3D modeling.
- Step 2: Preliminary flow modeling and injection point selection
- Step 3: CCS chain design
- Step 4: Risk assessment, risk mitigation and monitoring plan design
- Step 5: Environmental balance (carbon and energy footprint)
- Step 6: Economic evaluation (Discounted Cash Flow analysis).

Then environmental and economic calculations are based on realistic input data from a geological site characterization and technical sizing of the CCS plant.

The calculation was made assuming that all stored tons of CO_2 lead to carbon credit, whatever the carbon origin (fossil or biomass). It is important to point out that it is not currently the case in the European Trading Scheme [12].

Within the Kyoto framework, CO_2 emissions are accounted differently depending on their origin (e.g biomass vs. fossil). The regulation providing guidance for GHG accounting does not consider BECCS as eligible for the first commitment period of the protocol (2008-2012) [13]. However, to ensure viability of this project, emissions from biomass must be integrated into new GHG accounting protocols so that BECCS projects can be awarded emissions credit benefits.

Moreover, research should be further developed in order to store CO_2 coming from biomass. The influence of the presence of organic compounds in the CO_2 stream has indeed to be assessed, especially with respect to the interaction of such compounds with the deep biosphere [14].

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